CHESAPEAKE UTILITIES CORP
Form 10-K
March 05, 2015

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended: December 31, 2014
Commission File Number: 001-11590

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

State of Delaware (State or other jurisdiction of incorporation or organization)	51-0064146 (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)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock—par value per share $0.4867	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:
8.25% Convertible Debentures Due 2014
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨. No ý.
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨. No ý.
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 ý. 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 ý. No ¨.
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. ¨
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 the definitions of "accelerated filer," "large accelerated filer" and "smaller reporting

company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	¨	Accelerated filer	ý
Non-accelerated filer	¨	Smaller Reporting Company	¨

Indicate by a check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨. No ý.

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2014, the last business day of its most recently completed second fiscal quarter, based on the last trade price on that date, as reported by the New York Stock Exchange, was approximately $660.2 million.

The number of shares of Chesapeake Utilities Corporation Inc.'s common stock outstanding as of February 28, 2015 was 14,594,949.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

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GLOSSARY OF DEFINITIONS

401(k) SERP: Supplemental Executive Retirement Savings Plan
AFUDC: Allowance for funds used during construction
ASC: Accounting Standards Codification
Aspire Energy: Aspire Energy of Ohio, LLC, a newly formed, wholly-owned subsidiary of Chesapeake
ASU: Accounting Standards Update
Austin Cox: Austin Cox Home Services, Inc., a wholly-owned subsidiary of Chesapeake, providing heating, ventilation and air conditioning, plumbing and electrical services
BravePoint: BravePoint, Inc., our advanced information services subsidiary, headquartered in Norcross, Georgia, which was sold on October 1, 2014
CDD: Cooling degree-days, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit
Chesapeake: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
Chesapeake Service Company: Chesapeake Service Company, a subsidiary of Chesapeake and the parent company of Skipjack, CIC and ESRE
Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake
Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake
Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake
CHP: A combined heat and power plant being constructed by Eight Flags in Nassau County, Florida
CIC: Chesapeake Investment Company is an investment company incorporated in Delaware, which is wholly owned by Chesapeake Service Company
Columbia: Columbia Gas Transmission, LLC
Company: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
CP: Certificate of Public Convenience and Necessity
Deferred Compensation Plan: A non-qualified, deferred compensation arrangement under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers and fees
Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia
Dodd-Frank Act: The Dodd-Frank Wall Street Reform and Consumer Protection Act
DNREC: Delaware Department of Natural Resources and Environmental Control
DPA: Delaware Division of the Public Advocate
DSCP: Directors Stock Compensation Plan
Dt: Dekatherm, which is a natural gas unit of measurement that includes a standard measure for heating value
Dts/d: Dekatherms per day
Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned natural gas transmission subsidiary of Chesapeake
EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of Eastern Shore Gas Company

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Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake Onsight Services, LLC
EPA: United States Environmental Protection Agency
ESG: Eastern Shore Gas Company and its affiliates
ESRE: Eastern Shore Real Estate, Inc., a subsidiary that owns and leases office buildings in Delaware and Maryland to affiliates of Chesapeake.
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
Flo-gas: Flo-gas Corporation, a subsidiary of FPU
Fort Meade: The natural gas system purchased by FPU from the City of Fort Meade, Florida
FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake as of October 28, 2009, the date we acquired FPU
FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake
FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake
FRP: Fuel Retention Percentage
GAAP: Accounting principles generally accepted in the United States of America
Gatherco: Gatherco, Inc.
Glades: Glades Gas Co., Inc.
GRIP: Gas Reliability Infrastructure Program, which is a surcharge to natural gas customers designed to recover capital and other program-related costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services in Florida
GSR: Gas Service Rates
Gulf: Columbia Gulf Transmission Company
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
IRS: Internal Revenue Service
MDE: Maryland Department of Environment
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
MWH: Megawatt hour, which is a unit of measurement for electricity
NAM: Natural Attenuation Monitoring

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Note Agreement: Note Purchase Agreement entered into by Chesapeake with Note Holders on September 5, 2013
Note Holders: PAR U Hartford Life & Annuity Comfort Trust, The Prudential Insurance Company of America, The Gibraltar Life Insurance Co., Ltd., The Penn Mutual Life Insurance Company, Thrivent Financial for Lutherans, United of Omaha Life Insurance Company, and Companion Life Insurance Company, which are collectively the lenders that entered into the Note Agreement with Chesapeake on September 5, 2013
Notes: Series A and B unsecured Senior Notes that have been or will be entered into with the Note Holders
NYSE: New York Stock Exchange
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a new tariff associated with Eastern Shore's firm transportation service that allows Eastern Shore not to schedule service for up to 90 days during the peak months of November through April each year
OTC: Over-the-counter
PBF Energy: PBF Energy Inc.
Peninsula Pipeline: Peninsula Pipeline Company, Inc., our wholly-owned Florida intrastate pipeline subsidiary
Peoples Gas: The Peoples Gas System division of Tampa Electric Company
PESCO: Peninsula Energy Services Company, Inc., our wholly-owned natural gas marketing subsidiary
PIP: Performance Incentive Plan
PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake’s natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida
Rayonier: Rayonier Performance Fibers, LLC
Sandpiper: Sandpiper Energy, Inc., a wholly-owned subsidiary of Chesapeake, providing a tariff-based distribution service to customers in Worcester County, Maryland
Sanford Group: FPU and other responsible parties involved with the Sanford environmental site
SEC: Securities and Exchange Commission
Series A Notes: Series A of the unsecured Senior Notes issued on December 16, 2013 pursuant to the Note Agreement
Series B Notes: Series B of the unsecured Senior Notes to be issued on May 15, 2014 pursuant to the Note Agreement
Sharp: Sharp Energy, Inc., our wholly-owned propane distribution subsidiary
Sharpgas: Sharpgas, Inc., a subsidiary of Sharp
SICP: 2013 Stock and Incentive Compensation Plan, which replaced DSCP and PIP effective May 2, 2013

Skipjack: Skipjack, Inc. a subsidiary that owns and leases office buildings in Delaware and Maryland to affiliates of Chesapeake
S&P 500 Index: Standard & Poor’s 500 Index
TETLP: Texas Eastern Transmission, LP
Transco: Transcontinental Gas Pipe Line Company, LLC
Xeron: Xeron, Inc., our propane wholesale marketing subsidiary, based in Houston, Texas

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PART I

References in this document to “Chesapeake,” the “Company,” “we,” “us” and “our” mean Chesapeake Utilities Corporation, i divisions and/or its wholly-owned subsidiaries, as appropriate in the context of the disclosure.

Safe Harbor for Forward-Looking Statements

We make statements in this Annual Report on Form 10-K that do not directly or exclusively relate to historical facts. Such statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as “project,” “believe,” “expect,” “anticipate,” “intend,” “plan,” “estimate,” “continue,” “potential,” “forecast” or other similar words, or fut 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 and uncertainties. In addition to the risk factors described under Item 1A “Risk Factors,” the following important factors, among others, could cause actual future results to differ materially from those expressed in the forward-looking statements:

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and the degree to which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recovered in rates;
- the loss of customers due to 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;
- the impact to the asset values and resulting higher costs and funding obligations of the Company's pension and other postretirement benefit plans as a result of potential downturns in the financial markets, lower discount rates or impacts associated with the Patient Protection and Affordable Care Act;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to establish and maintain new key supply sources;
- the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs; and
- risks related to cyber-attack or failure of information technology systems.

ITEM 1. BUSINESS.

CORPORATE OVERVIEW

Chesapeake Utilities Corporation is a Delaware corporation formed in 1947. We are a diversified energy company engaged, through our operating divisions and subsidiaries, in various energy and other businesses. We operate primarily on the Delmarva Peninsula and throughout Florida, providing natural gas distribution and transmission, electric distribution and propane distribution service. The core of our business is regulated energy services, which provides stable earnings through our utility operations. Our unregulated businesses provide opportunities to achieve returns greater than those of a traditional utility. The following charts present operating income by type of energy served and geographic area for the year ended December 31, 2014 and average investment by type of energy served and geographic area as of December 31, 2014.

OPERATING SEGMENTS

We operate within three reportable segments: Regulated Energy, Unregulated Energy and Other.

The Regulated Energy segment includes our natural gas distribution, natural gas transmission and electric distribution operations. All operations in this segment are regulated, as to their rates and service, by the PSC having jurisdiction in each state in which we operate or by the FERC in the case of Eastern Shore.

The Unregulated Energy segment includes our propane distribution, propane wholesale marketing and natural gas marketing operations, which are unregulated as to their rates and services. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

Prior to September 30, 2014, our “Other” segment consisted primarily of BravePoint, our advanced information services subsidiary. On October 1, 2014, we sold BravePoint; consequently, the Other segment now solely consists of unregulated subsidiaries that own real estate leased to Chesapeake, as well as certain corporate costs not allocated to other operations.

The following chart shows our principal business structure by segment:

The following table shows the size of each of our operating segments based on operating income for the year ended December 31, 2014 and total assets as of December 31, 2014:

(dollars in thousands)	Operating Income			Total Assets		
Regulated Energy	$50,451	81	%	$796,021	88	%
Unregulated Energy	11,723	19	%	84,732	9	%
Other	105	—	%	23,716	3	%
Total	$62,279	100	%	$904,469	100	%

Additional financial information by business segment is set forth in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, and Item 8, Financial Statements and Supplementary Data (see Note 5, Segment Information, in the Consolidated Financial Statements).

REGULATED ENERGY

Overview of Business

Regulated Energy is our largest segment and consists of our natural gas distribution operations in Delaware, Maryland and Florida; our electric distribution operation in Florida; and our natural gas transmission operations on the Delmarva Peninsula and in Florida. Our natural gas and electric distribution operations, which are local distribution utilities, generate revenues based on tariff rates approved by the PSC of each state in which we operate. The PSCs have also authorized our utilities to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. Some of our customers in Maryland are currently served with propane under PSC-approved tariff rates as we evaluate the potential conversion to natural gas of some of the underground propane distribution system customers acquired in 2013. These customers are included in the Delmarva natural gas distribution operation.

Eastern Shore, our interstate natural gas transmission subsidiary, bills its customers based upon the FERC-approved tariff rates, and the FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved tariff rates. Peninsula

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Pipeline, our Florida intrastate pipeline subsidiary subject to regulation by the Florida PSC, has negotiated contracts with third-party customers and with certain affiliates. Our rates are designed to provide the opportunity to generate revenues to recover all prudently incurred costs and provide a return on rate base sufficient to pay interest on debt and a reasonable return for our shareholders. Rate base generally consists of the original cost of utility plant less accumulated depreciation on utility plant in service, working capital and certain other assets and depending upon the particular regulatory jurisdiction, may also include deferred income tax liabilities and other additions or deletions.
The natural gas commodity market for Chesapeake’s Florida division and FPU’s Indiantown division has been deregulated. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in those jurisdictions. For all of our other local distribution utilities, we have fuel cost recovery mechanisms authorized by the PSCs that allow us to periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers.

Weather

Revenues from our residential and commercial sales are affected by seasonal variations in weather conditions, which directly influence the volume of natural gas and electricity sold and delivered. Specifically, customer demand substantially increases during the winter months, when natural gas and electricity are used for heating. For electricity, customer demand also increases during the summer months, when electricity is used for cooling. Accordingly, the volumes sold for these purposes are directly affected by the severity of summer and winter weather and can vary substantially from year to year. We measure the relative impact of weather by using an accepted degree-day methodology. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day’s average temperature. 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 below 65 degrees Fahrenheit is counted as one heating degree-day. Each degree of temperature above 65 degrees Fahrenheit is counted as one cooling degree-day. Normal heating degree-days are based on the most recent 10-year average.

In an effort to stabilize the level of net revenues collected from customers in Maryland regardless of weather conditions, Chesapeake’s Maryland division implemented a weather normalization adjustment for our residential heating and smaller commercial heating customers. A weather normalization adjustment is a billing adjustment mechanism that is designed to eliminate the effect of deviations from average seasonal temperatures on utility net revenues. We do not currently have any weather normalization or “decoupled” rate mechanisms for our other local distribution utilities.

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Operational Highlights

The following table presents operating revenues, volume and average customers by customer class for our natural gas and electric distribution operations for the year ended December 31, 2014:

(in thousands)	Delmarva Natural Gas Distribution[2]		Florida Natural Gas Distribution [3]		FPU Electric Distribution	
Operating Revenues						
Residential	$65,958	60 %	$29,346	34 %	$43,023	57 %
Commercial	36,452	33 %	37,567	43 %	37,553	50 %
Industrial	6,912	6 %	17,880	20 %	3,569	5 %
Other [1]	1,244	1 %	2,578	3 %	(8,611)	(12)%
Total Operating Revenues	$110,566	100 %	$87,371	100 %	$75,534	100 %
Volume (in Dts for natural gas/MWHs for electric)						
Residential	3,761,034	31 %	1,624,303	7 %	310,218	47 %
Commercial	3,783,741	31 %	4,313,658	19 %	312,557	49 %
Industrial	4,453,053	37 %	16,460,443	74 %	29,090	5 %
Other	75,117	1 %	34,450	— %	(8,533)	(1)%
Total	12,072,945	100 %	22,432,854	100 %	643,332	100 %
Average Customers						
Residential	62,216	90 %	65,247	90 %	23,865	76 %
Commercial	6,534	9 %	5,731	8 %	7,405	24 %
Industrial	111	— %	1,381	2 %	2	— %
Other	7	1 %	—	— %	—	— %
Total	68,868	100 %	72,359	100 %	31,272	100 %

[1] Operating Revenues from "Other" sources include unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges, fees for billing services provided to third parties, and adjustments for pass-through taxes.

[2] Delmarva natural gas distribution operation includes Chesapeake's Delaware and Maryland divisions in addition to Sandpiper.

[3] Florida natural gas distribution operation includes Chesapeake's Florida Division, FPU and FPU's Indiantown and Fort Meade divisions.

The following table presents operating revenues and design day capacity for Eastern Shore for the year ended December 31, 2014 and contracted firm transportation capacity at December 31, 2014:

(in thousands)	Eastern Shore	
Operating Revenues		
Local distribution companies - affiliated [1]	$15,249	36 %
Local distribution companies - non-affiliated	11,379	27 %
Commercial and industrial	15,561	37 %
Other [2]	47	— %
Total Operating Revenues	$42,235	100 %

Contracted firm transportation capacity (in Dts/d)

Local distribution companies - affiliated	101,152	43	%
Local distribution companies - non-affiliated	67,293	28	%
Commercial and industrial	67,748	29	%
Total	236,193	100	%
Designed day capacity (in Dts/d)	236,193	100	%

(1) Eastern Shore's service to our local distribution affiliates is based on FERC-approved rates and is an integral component of the cost associated with providing natural gas supplies for those affiliates. We eliminate operating revenues of Eastern Shore against the cost of sales of those affiliates; however, our local distribution affiliates include this amount in their purchased fuel cost and recover it through fuel cost recovery mechanisms.
(2) Operating revenues from "Other" sources are from the rental of gas properties.

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Peninsula Pipeline has six contracts with both affiliated and non-affiliated customers to provide firm transportation service. All of the contracts provide a fixed annual transportation fee. For the year ended December 31, 2014, operating revenues of Peninsula Pipeline were $3.5 million, $2.3 million of which were related to service to FPU under a contract with FPU, which has been approved by the Florida PSC. Peninsula Pipeline's operating revenue from FPU is eliminated against the cost of sales in consolidation; however, FPU includes this amount in its purchased fuel cost and recovers it through the fuel cost recovery mechanism.

Regulatory Matters

The following table highlights the key regulatory structure and the most recent base rate proceeding information for each of our major utilities:

	Chesapeake - Delaware Division	Chesapeake - Florida Division	FPU Natural Gas	FPU Electric	Chesapeake - Maryland Division	Eastern Shore
Commission Structure:	5 commissioners Part-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Presidential Appointment
Regulatory Jurisdiction:	Delaware PSC	Florida PSC	Florida PSC	Florida PSC	Maryland PSC	FERC
Base Rate Proceeding:						
Delay in collection of rates subsequent to filing application	60 days	90 days	90 days	90 days	180 days	Up to 180 days
Date of most recent application	7/6/2007	7/14/2009	12/17/2008	4/28/2014	5/1/2006	12/30/2010
Effective date of permanent rates	9/30/2008	1/14/2010	1/14/2010(1)	11/1/2014	12/1/2007	7/29/2011
Rate increase (decrease) approved	$325,000	$2,536,300	$7,969,000	$3,750,000	$648,000	$805,000
Rate of return approved	10.25%(2)	10.80%(2)	10.85%(2)	10.25%(2)	10.75%(2)	13.90%(3)

(1) Effective date of the Order approving settlement agreement, which adjusted rates originally approved on June 4, 2009.

(2) Allowed return on equity.

(3) Allowed pre-tax, pre-interest rate of return

As of December 31, 2014, we had invested the following in our regulated operations: $111.4 million for Delmarva natural gas distribution; $211.1 million for Florida natural gas and electric distribution; and $157.1 million for natural gas transmission.

The terms of the settlement agreement for the FPU electric division rate case prescribe an authorized return on equity range of 9.25 to 11.25 percent, with a mid-point of 10.25 percent. In addition, the FPU electric division cannot file for a base rate increase prior to December 2016, unless its allowed return on equity falls below the authorized range. If the allowed return on equity exceeds the authorized range, the Office of the Public Counsel can seek a rate decrease.

The terms of the settlement agreement in Eastern Shore's most recent base rate proceeding provide a five-year moratorium on Eastern Shore's right to file a base rate increase and other parties' rights to challenge Eastern Shore's rates. It allows Eastern Shore to file for rate adjustments during those five years in the event certain costs related to government-mandated obligations are incurred and Eastern Shore's pre-tax earnings do not equal or exceed 13.9 percent. Eastern Shore is also required to file a base rate proceeding by January 2017.

In May 2013, the Maryland PSC approved our application for approval of the acquisition of the ESG operating assets and the transfer of the ESG franchises to Sandpiper. In this application, the Maryland PSC also approved a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, Maryland. Sandpiper is required to file a base rate proceeding by November 2015, two and a half years after Sandpiper commenced service in Worcester County, Maryland (May 2013).

In addition to the base rates approved by the PSCs, certain of our local distribution utilities have additional surcharge mechanisms, which were separately approved by their respective PSCs. The most notable surcharge mechanisms include Delaware's surcharge to increase the availability of natural gas in portions of eastern Sussex County, Delaware; Maryland's surcharge designed to recover the costs associated with conversions to natural gas in Worcester County, Maryland, and Florida's GRIP surcharge designed to

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recover capital and other costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains.

See Item 8, Financial Statements and Supplementary Data (Note 18, Rates and Other Regulatory Activities, in the Consolidated Financial Statements) for more information.

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 industrial customers that are able to use fuel oil or propane as an alternative to natural gas. When oil or propane prices decline, these interruptible customers may convert to an alternative fuel source to satisfy their fuel requirements, and our sales volumes may decline. To address the uncertainty of alternative fuel prices, we use flexible pricing arrangements on both the supply and sales sides of our business to compete with alternative fuel price fluctuations.

Large industrial natural gas customers may be able to bypass our distribution and transmission systems and make direct connections with “upstream” interstate transmission pipelines when such connections are economically feasible. Certain large industrial electric customers may be capable of generating electricity for their own consumption. Although the risk of bypassing our systems is not considered significant, we may adjust services and rates for these customers to retain their business in certain situations.

Supplies, Transmission and Storage

We believe that the availability of supply and transmission of natural gas and electricity is adequate under existing arrangements to meet the anticipated needs of customers.

Chesapeake’s Delaware and Maryland divisions use their firm transportation resources to meet a significant percentage of their projected demand requirements. They purchase firm natural gas supplies to meet those projected requirements with purchases of base load, daily spot supplies and storage service. They have both firm and interruptible transportation service contracts with five interstate “open access” pipeline companies (Eastern Shore, Transco, Columbia, Gulf and TETLP) in order to meet customer demand. Their distribution system is directly interconnected with Eastern Shore’s pipeline, which is directly interconnected with the upstream pipelines of Transco, Columbia and TETLP. The Gulf pipeline is directly interconnected with Columbia and indirectly interconnected with Eastern Shore’s pipeline. Chesapeake’s Delaware division has 72,254 Dts of maximum daily firm transportation capacity with Eastern Shore through contracts expiring on various dates between 2015 and 2028. It also has a total of 66,483 Dts of maximum daily firm transportation capacity with four upstream pipelines through contracts expiring between 2015 and 2028. Chesapeake’s Maryland division has 26,448 Dts of maximum daily firm transportation capacity with Eastern Shore through contracts expiring on various dates between 2015 and 2027 and a total of 26,228 Dts of maximum daily firm transportation capacity with four upstream pipelines through contracts expiring between 2015 and 2027. The Delaware and Maryland divisions also have the capability to use propane-air peak-shaving equipment to supplement or displace natural gas purchases.

Chesapeake's Delaware and Maryland divisions contract with an unaffiliated energy marketing and risk management company through an asset management agreement to optimize their transportation and storage capacity and secure an adequate supply of natural gas. The asset manager pays our divisions a fee, which our divisions share with their customers. The current asset management agreement expires in March 2017.

Sandpiper has a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term, with approximately five years remaining under this contract. Sandpiper's current annual commitment is estimated at approximately 6.5 million gallons. Sandpiper also has 2,450 Dts of maximum daily firm transportation capacity available on Eastern Shore through a contract expiring in 2027.

Chesapeake’s Florida division has firm transportation service agreements with FGT and Gulfstream for daily firm transportation capacity ranging from 26,092 to 28,639 Dts expiring on various dates between 2020 and 2025. As a result of the deregulation of the natural gas sales market in Florida, the Florida PSC approved a program permitting the release of all of the capacity under these agreements to various third parties, including PESCO, our natural gas marketing subsidiary. We are contingently liable to FGT and Gulfstream if any party that acquired the capacity through release fails to pay the capacity charge.

FPU has firm transportation service agreements with FGT, Florida City Gas and Peninsula Pipeline, totaling 28,203 to 54,257 Dts of daily firm transportation capacity expiring on various dates between 2015 and 2033. FPU uses gas marketers and producers to procure all of its gas supplies to meet projected requirements. FPU also uses Peoples Gas to provide wholesale gas sales service in areas far from its interconnections with FGT.

Eastern Shore has three contracts with Transco for a total of 7,292 Dts of firm daily storage injection and withdrawal entitlements and total storage capacity of 288,003 Dts expiring on various dates between 2018 and 2023. Eastern Shore retains these firm

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storage services in order to provide swing transportation service and firm storage service to customers requesting such services.

FPU currently purchases its wholesale electricity primarily from two suppliers, JEA and Gulf Power, under full requirements contracts expiring in December 2017 and 2019, respectively. The JEA contract provides generation and transmission service to northeast Florida. The Gulf Power contract provides generation and transmission service to northwest Florida. FPU also has a renewable energy purchase agreement with Rayonier to purchase between 1.7 MWH and 3.0 MWH of electricity annually that expires in 2036. In September 2014, FPU entered into an agreement with its affiliate, Eight Flags, to purchase up to 20 MWH of electricity from a CHP plant, once construction of the plant is completed, which is projected to be in the third quarter of 2016. Both agreements with Rayonier and Eight Flags will serve a portion of FPU's customer load in northeast Florida.

UNREGULATED ENERGY

Overview of Business

Our Unregulated Energy segment provides propane distribution, propane wholesale marketing, natural gas marketing services and other unregulated energy-related services to customers. Revenues generated from the Unregulated Energy segment are not subject to any federal, state or local pricing regulations. Our businesses in the Unregulated Energy segment typically complement our regulated businesses by offering propane as a fuel source where natural gas is not readily available or providing natural gas marketing service to customers who are able to procure their own supplies. Through competitive pricing and supply management, these businesses provide the opportunity to generate returns greater than those of a traditional utility.

Propane Distribution - Overview of Business

Our propane distribution operations sell propane primarily to residential, commercial/industrial and wholesale customers on the Delmarva Peninsula and in southeastern Pennsylvania through Sharp and Sharpgas and in Florida through FPU and Flo-gas. Many of our propane distribution customers are “bulk delivery” customers. We make deliveries of propane to the bulk delivery customers as needed, based on the level of propane remaining in the tank located at the customer’s premises. We invoice and record revenues for our bulk delivery service customers at the time of delivery, rather than upon customers’ actual usage, since the customers typically own the propane gas in the tanks on their premises. We also have underground propane distribution systems serving various neighborhoods and communities and have installed meters on customer premises to measure consumption and bill them monthly.

Propane Distribution - Weather

Revenues from our propane distribution sales activities are affected by seasonal variations in weather conditions. Weather conditions directly influence the volume of propane sold and delivered to customers; specifically, their demand substantially increases during the winter months when propane is used for heating. The timing of deliveries to the bulk delivery customers can also vary significantly from year to year depending on weather variation. Accordingly, the propane volumes sold for heating are directly affected by the severity of winter weather and can vary substantially from year to year. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption.

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Propane Distribution - Operational Highlights

For the year ended December 31, 2014, operating revenues, total gallons sold and average customers by customer class for our Delmarva and Florida propane distribution operations were as follows:

(in thousands)	Delmarva Peninsula and Pennsylvania			Florida		
Operating Revenues						
Residential bulk	$28,564	30	%	$6,187	28	%
Residential metered	9,874	10	%	5,148	23	%
Commercial bulk	22,082	23	%	6,886	31	%
Commercial metered	—	—	%	2,138	10	%
Wholesale	31,620	33	%	1,281	6	%
Other [(1)]	4,662	4	%	560	2	%
Total Operating Revenues	$96,802	100	%	$22,200	100	%
Volume (in gallons)						
Residential bulk	10,003	21	%	1,410	21	%
Residential metered	3,783	8	%	1,018	15	%
Commercial bulk	11,554	25	%	2,746	41	%
Commercial metered	—	—	%	702	10	%
Wholesale	21,454	46	%	844	13	%
Other	—	—	%	10	—	%
Total	46,794	100	%	6,730	100	%
Average customers						
Residential bulk	24,824	67	%	8,698	53	%
Residential metered	7,477	20	%	6,395	39	%
Commercial bulk	3,929	11	%	1,055	6	%
Commercial metered	—	—	%	277	2	%
Wholesale	33	—	%	6	—	%
Other	578	2	%	—	—	%
Total	36,841	100	%	16,431	100	%

(1) Operating revenues from "Other" sources include revenues from customer loyalty programs; delivery, service and appliance fees; and unbilled revenues.

Propane Distribution - Competition

We compete with several other propane distributors in our geographic markets, primarily on the basis of price and service. Our competitors generally include local outlets of national distributors and local independent distributors, whose proximity to customers entails lower costs to provide service. As an energy source, propane competes with home heating oil and electricity, which are typically more expensive (based on equivalent unit of heat value). 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.

Propane Distribution - Supplies, Transportation and Storage

We purchase propane for our propane distribution operations primarily from suppliers, including major oil companies, independent producers of natural gas liquids and from Xeron. Although supplies of propane from these and other sources are generally readily available for purchase, extreme market conditions, such as significant fluctuation in weather, closing of refineries and disruption in supply chains, could result in a reduction in available supplies.

Propane is transported by trucks and railroad cars from refineries, natural gas processing plants or pipeline terminals to our bulk storage facilities. We own various bulk propane storage facilities with an aggregate capacity of approximately 3.8 million gallons in Delaware, Maryland, Pennsylvania, Virginia and Florida. From these storage facilities, propane is delivered by “bobtail” trucks, owned and operated by us, to tanks located at the customers’ premises.

Propane Wholesale Marketing

Through Xeron, we market propane to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States. Xeron enters into forward contracts with various counterparties to commit to purchase or sell an agreed-upon quantity of propane at an agreed-upon price at a specified future date, which typically ranges from one to six months from the execution of the contract. At the expiration of the forward contracts, Xeron typically settles its purchases and sales financially, without taking physical delivery of the propane. Xeron also enters into futures and other option contracts that are traded on the InterContinentalExchange, Inc. The level and profitability of the propane wholesale marketing activity is affected by both propane wholesale price volatility and liquidity in the wholesale market. In 2014, Xeron had operating revenues, net of the associated cost of propane sold totaling approximately $1.5 million. For further discussion of Xeron's wholesale marketing activities, market risks and controls that monitor Xeron's risks, refer to Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Risk. Xeron does not own physical storage facilities or equipment to transport propane; however, it contracts for storage and pipeline capacity to facilitate the sale of propane on a wholesale basis.

Natural Gas Marketing

We provide natural gas supply and supply management services through PESCO to 3,053 customers in Florida and 24 customers located primarily on the Delmarva Peninsula. In 2014, PESCO had operating revenues of $51.1 million in Florida and $8.6 million from customers located primarily on the Delmarva Peninsula. PESCO competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to commercial and industrial customers through competitively-priced contracts. PESCO does not own or operate any natural gas transmission or distribution assets. The gas that PESCO sells is delivered to retail customers through affiliated and non-affiliated local distribution company systems and transmission pipelines. PESCO bills its customers directly or through the billing services of the regulated utilities that deliver the gas.

Other Unregulated Businesses

We provide heating, ventilation and air conditioning, plumbing and electrical services through Austin Cox to residential, commercial and industrial customers throughout the lower Delmarva Peninsula. FPU sells energy-related merchandise in Florida. Operating revenues in 2014 from these other unregulated businesses totaled $4.8 million.

On January 30, 2015, we entered into a merger agreement to acquire Gatherco. Upon consummation of the transaction, Gatherco will merge into Aspire Energy, a newly formed, wholly-owned subsidiary of Chesapeake. At closing, we expect to issue 593,005 shares of our common stock, valued at $29.9 million, pay $27.6 million in cash and assume Gatherco's debt, estimated to be $1.7 million. We expect to pay off this debt shortly after closing. Gatherco is a natural gas infrastructure company providing natural gas midstream services. Gatherco's assets include 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Gatherco provides natural gas gathering services and natural gas liquid processing services to over 300 producers, and supplies natural gas to over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity which Gatherco manages under an operating agreement. The transaction is subject to approval by Gatherco's shareholders and is expected to close in the second quarter of 2015.

OTHER

Overview of Business

The "Other" segment consists primarily of other unregulated subsidiaries, including Skipjack and ESRE that own real estate leased to affiliates; and certain unallocated corporate costs, which are not directly attributable to a specific business unit. Skipjack and ESRE own and lease office buildings in Delaware and Maryland to affiliates of Chesapeake. CIC is an investment company incorporated in Delaware.

ENVIRONMENTAL COMPLIANCE

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate the effect on the environment of the disposal or release of specified substances at current and former operating sites. We have participated in the investigation, assessment or remediation, and have exposures at six former MGP sites. At December 31, 2014, we had $10.5 million in environmental liabilities, representing our estimate of such future costs principally related to two of the six former MGP sites. The most significant site is located in West Palm Beach, Florida, where FPU previously operated an MGP and is currently implementing a remedial plan approved by the FDEP. The estimated cost of remediation for the West Palm Beach site ranges from approximately $4.5 million to $15.4 million. Chesapeake is also currently assessing a remediation plan and actively remediating a former MGP site in Winter Haven, Florida. The estimated cost of remediation for the Winter Haven site is expected not to exceed $443,000. In addition to the six former MGP sites, we received a report from DNREC in January 2015 regarding groundwater contamination at a different MGP site in Delaware. We estimate a remedial cost ranging from $273,000 to $465,000 for this site. We are also in discussion with the MDE regarding another former MGP site in Maryland. For additional information on each site, refer to Item 8, Financial Statements and Supplementary Data (see Note 19, Environmental Commitments and Contingencies in the Consolidated Financial Statements).

Base rates of our local distribution utilities include, or are expected to include, recovery of environmental remediation costs adequate to fully recover our current estimate of remediation costs. We continue to expect that any costs related to environmental remediation and related activities beyond our current estimate will also be recoverable from customers through rates.

EMPLOYEES

As of December 31, 2014, we had a total of 753 employees, 118 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers and Commercial Workers Union, whose collective bargaining agreements expire in 2016.

FINANCIAL INFORMATION ABOUT GEOGRAPHICAL AREAS

All of our material operations, customers and assets are located in the United States.

AVAILABLE INFORMATION AND CORPORATE GOVERNANCE DOCUMENTS

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments to these reports that we file with or furnish to the SEC are available free of charge at our website, www.chpk.com, as soon as reasonably practicable after we electronically file these reports with, or furnish these reports to, the SEC. The content of this website is not part of this report. These reports, and amendments to these reports, that we file with or furnish to the SEC are also available on the SEC's website, www.sec.gov. The public may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room, 100 F Street, N.E., Washington, DC 20549-5546. The public may obtain information from the Public Reference Room by calling the SEC at 1-800-SEC-0330.

In addition, the following documents are available free of charge on our website, www.chpk.com:

- Business Code of Ethics and Conduct applicable to all employees, officers and directors;
- Code of Ethics for Financial Officers;
- Corporate Governance Guidelines;
- Charters for the Audit Committee, Compensation Committee and Corporate Governance Committee of the Board of Directors; and
- Corporate Governance Guidelines on Director Independence.

Any of these reports or documents may also be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, DE 19904.

If we make any amendment to, or grant a waiver of, any provision of the Business Code of Ethics and Conduct or the Code of Ethics for Financial Officers applicable to our principal executive officer, president, principal financial officer, principal accounting officer or controller, the amendment or waiver will be disclosed within four business days in a press release, by website disclosure, or by filing a current report on Form 8-K with the SEC.

CERTIFICATION TO THE NYSE

Our Chief Executive Officer certified to the NYSE on June 4, 2014, that as of that date, he was unaware of any violation by Chesapeake of the NYSE's corporate governance listing standards.

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ITEM 1A. RISK FACTORS.

The following is a discussion of the primary factors that may affect the operations or financial performance of our regulated and unregulated businesses. Refer to the section entitled Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this report for an additional discussion of these and other related factors that affect our operations and/or financial performance.

FINANCIAL RISKS

Instability and volatility in the financial markets could negatively impact our ability to access capital at competitive rates and affect our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth.

Our business strategy includes the continued pursuit of growth, both organically and through acquisitions. To the extent that we do not generate sufficient cash flow from operations, we may incur additional indebtedness to finance our growth. We rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flows from our operations. 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. However, if we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

A downgrade in our credit rating could adversely affect our access to capital markets and our cost of capital.

Our ability to obtain adequate and cost-effective capital depends on our credit ratings, which are greatly affected by our financial performance and the liquidity of financial markets. A downgrade in our current credit ratings could adversely affect our access to capital markets, as well as our cost of capital.

If we fail to comply with our debt covenant obligations, we could experience adverse financial consequences that could affect our liquidity and ability to borrow funds.

Our long-term debt obligations and committed short-term lines of credit contain financial covenants related to debt-to-capital ratios and interest-coverage ratios. Failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration could cause a material adverse change in our financial condition.

An increase in interest rates may adversely affect our results of operations and cash flows.

An increase in interest rates, without the recovery of the higher cost of debt in the sales and/or transportation rates we charge our utility customers, could adversely affect future earnings. An increase in short-term interest rates could negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories and to temporarily finance capital expenditures.

Inflation may impact our results of operations, cash flows and financial position.

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for regulated operations and closely monitor the returns of our unregulated operations. There can be no assurance that we will be able to obtain adequate and timely rate increases to offset the effects of inflation.

Fluctuations in propane gas could negatively affect results or operations.

To compensate for fluctuations in propane gas prices, we adjust our propane selling prices to the extent allowed by the market. There can be no assurance, however, that we will be able to increase propane sales prices sufficiently to compensate fully for such fluctuations in the cost of propane gas to us. If we are unable to increase propane sales prices sufficiently to compensate fully for such fluctuations, our earnings could be negatively affected, which would adversely impact our results of operations.

Our energy marketing subsidiaries are exposed to market risks beyond our control, which could adversely affect our financial results and capital requirements.

Our energy marketing subsidiaries are subject to market risks beyond our control, including market liquidity and commodity price volatility. Although we maintain risk management policies, we may not be able to offset completely the price risk associated with volatile commodity prices, which could lead to volatility in earnings. Physical trading also has price risk on any net open positions at the end of each trading day, as well as volatility resulting from: (i) intra-day fluctuations of natural gas and/or propane prices, and (ii) daily price movements between the time natural gas and/or propane is purchased or sold for future delivery and the time the related purchase or sale is economically hedged. The determination of our net open position at the end of any trading day requires us to make assumptions as to future circumstances, including the use of natural gas and/or propane by our customers in relation to anticipated market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions daily. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner, because the changes in fair value of trading contracts are immediately recognized as profits or losses for financial accounting purposes. This volatility may occur, with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated.

Our energy marketing subsidiaries are exposed to credit risk of their counterparties.

Our energy marketing subsidiaries extend credit to counterparties and continually monitor and manage collections aggressively. Each of these subsidiaries is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform, and any underlying collateral is inadequate, we could experience financial losses.

Our energy marketing subsidiaries are dependent upon the availability of credit to successfully operate their businesses.

Our energy marketing subsidiaries are dependent upon the availability of credit to buy propane and natural gas for resale or to trade. If financial market conditions decline generally, or the financial condition of these subsidiaries or of our Company declines, then the cost of credit available to these subsidiaries could increase. If credit is not available, or if credit is more costly, our results of operations, cash flows and financial condition may be adversely affected.

Current market conditions could adversely impact the return on plan assets for our pension plans, which may require significant additional funding.

Our pension plans are closed to new employees, and the future benefits are frozen. The costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans and the discount rates used to estimate the pension benefit obligations. As a result of the extreme volatility and disruption in the domestic and international equity, bond and interest rate markets in recent years, the asset values and benefit obligations of Chesapeake's and FPU's Pension Plans have fluctuated significantly since 2008. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values and further declines in discount rates may necessitate accelerated funding of the plans in the future to meet minimum federal government requirements as well as higher pension expense to be recorded in future years. Adverse changes in the asset values and benefit obligations of our pension plans may require us to record higher pension expense and fund obligations earlier than originally planned, which would have an adverse impact on our cash flows from operations, decrease borrowing capacity and increase interest expense.

OPERATIONAL RISKS

Fluctuations in weather may cause a significant variance in our earnings.

Our natural gas and propane distribution operations are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we sell and deliver to our customers. A significant portion of our natural gas and propane distribution revenues is derived from the sales and deliveries to residential and commercial heating customers during the five-month peak heating season (November through March). If the weather is warmer than normal, we sell and deliver less natural gas and propane to customers, and earn less revenue, which could adversely affect our results of operations, cash flows and financial condition.

Our electric operation is also affected by variations in weather conditions generally and unusually severe weather conditions. However, electricity consumption is generally less seasonal than natural gas and propane because it is used for both heating and cooling in our service areas.

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The amount and availability of natural gas, propane and electricity supplies are difficult to predict; a substantial reduction in available supplies could reduce our earnings in those segments.

Natural gas, propane and electricity production can be affected by factors beyond our control, such as weather and disruptions or closings of energy facilities. If we are unable to obtain sufficient natural gas, electricity and propane supplies to meet demand, results in those businesses may be adversely affected. Any substantial decrease in the availability of supplies of natural gas, propane and electricity could result in increased supply costs and higher prices for customers, which could also adversely affect our financial condition and results of operations.

We rely on a limited number of natural gas, propane and electricity suppliers, the loss of which could have a material adverse effect on our financial condition and results of operations.

We have entered into various agreements with suppliers to purchase natural gas, propane and electricity to serve our customers. The loss of any significant suppliers or our inability to renew these contracts at favorable terms upon their expiration could significantly affect our ability to serve our customers and have a material adverse impact on our financial condition and results of operations.

A substantial disruption or lack of growth in interstate natural gas pipeline transmission and storage capacity or electric transmission capacity may impair our ability to meet customers' existing and future requirements.

In order to meet existing and future customer demands for natural gas and electricity, we must acquire sufficient supplies of natural gas and electricity, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate upstream transmission capacity for our distribution systems while considering the dynamics of the interstate pipeline and storage and electric transmission markets, our own on-system resources, as well as the characteristics of our markets. Our financial condition and results of operations would be materially and adversely affected if the future availability of these capacities were insufficient to meet future customer demands for natural gas and electricity. Currently, our Florida natural gas operation relies primarily on one pipeline system, FGT, for most of its natural gas supply and transmission. Our Florida electric operation relies primarily on two suppliers, Gulf Power for the northwest service territory and JEA for the northeast service territory. Any interruption to these systems could adversely affect our ability to meet the demands of FPU's customers and our earnings.

Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane distribution operations, which may adversely affect our results of operations, cash flows and financial condition.

Natural Gas/Electricity. Higher natural gas prices can significantly increase the cost of gas billed to our natural gas customers. Increases in the cost of coal, natural gas and other fuels used to generate electricity can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, which decreases their supply of natural gas and electricity, could result in increased supply costs and higher prices for our customers. Such cost increases generally have no immediate effect on our revenues and net income because of our regulated fuel cost recovery mechanisms. However, our net income may be reduced by higher expenses that we may incur for uncollectible customer accounts and by lower volumes of natural gas and electricity deliveries when customers reduce their consumption. Therefore, increases in the price of natural gas, coal and other fuels can affect our operating cash flows and the competitiveness of natural gas and electricity as energy sources.

Propane. Propane costs are subject to volatile changes as a result of product supply or other market conditions, including weather, economic and political factors affecting crude oil and natural gas supply or pricing. For example, weather conditions could damage production or transportation facilities, which could result in decreased supplies of propane, increased supply costs and higher prices for customers. Such cost changes can occur rapidly and can affect profitability. There is no assurance that we will be able to pass on propane cost increases fully or immediately, particularly when propane costs increase rapidly. Therefore, average retail sales prices can vary significantly from year to year as product costs fluctuate in response to propane, fuel oil, crude oil and natural gas commodity market conditions. In addition, in periods of sustained higher commodity prices, declines in retail sales volumes due to

reduced consumption and increased amounts of uncollectible accounts may adversely affect net income.
Our propane inventory is subject to inventory valuation risk, which may result in a write-down of inventory.
Our propane distribution operations own bulk propane storage facilities, with an aggregate capacity of approximately 3.8 million gallons. We purchase and store propane based on several factors, including inventory levels and the price outlook. We may purchase large volumes of propane at current market prices during periods of low demand and low prices, which generally occur during the summer months. Propane is a commodity, and as such, its price is subject to volatile fluctuations in response to changes in supply or other market conditions. We have no control over these market conditions. Consequently, the wholesale purchase price can change rapidly over a short period of time. The retail market price for propane could fall below the price at which we made

the purchases, which would adversely affect our profits or cause sales from that inventory to be unprofitable. In addition, falling propane prices may result in inventory write-downs, as required by GAAP, if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

Operating events affecting public safety and the reliability of our natural gas and electric distribution and transmission systems could adversely affect our operations and increase our costs.

Our natural gas and electric operations are exposed to operational events and risks, such as major leaks, outages, mechanical failures and breakdown, operations below the expected level of performance or efficiency, and accidents that could affect public safety and the reliability of our distribution and transmission systems, significantly increase costs and cause loss of customer confidence. If we are unable to recover all or some of these costs from customers through the regulatory process, our authorized rate of return, our results of operations, financial condition and cash flows could be adversely affected.

We operate in a competitive environment, and we may lose customers to competitors.

Natural Gas. Our natural gas marketing operations compete with third-party suppliers to sell natural gas to commercial and industrial customers. Our natural gas transmission and distribution operations compete with interstate pipelines when our transmission and/or distribution customers are located close enough to a competing pipeline to make direct connections economically feasible. Failure to retain and grow our natural gas customer base would have an adverse effect on our financial condition, cash flows and results of operations.

Electric. While there is active wholesale power sales competition in Florida, our retail electric business through FPU has remained substantially free from direct competition from other electric service providers. Generally, however, our retail electric business through FPU remains subject to competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions, or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect our results of operations, cash flows and financial condition.

Propane. Our propane distribution operations compete with other propane distributors, primarily on the basis of service and price. Some of our competitors have significantly greater resources. Our ability to grow the propane distribution business is contingent upon capturing additional market share, expanding into new markets, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane distribution operations would have an adverse effect on our results of operations, cash flows and financial condition.

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

Energy conservation could lower energy consumption, which would adversely affect our earnings.

We have seen various legislative and regulatory initiatives to promote energy efficiency and conservation at both the federal and state levels. In response to the initiatives in the states in which we operate, we have implemented programs to promote energy efficiency by our current and potential customers. To the extent a PSC allows us to recover the cost of such energy efficiency programs, funding for such programs is recovered through the rates we charge to our regulated customers. However, lower energy consumption as a result of energy efficiency and conservation by current and potential customers may adversely affect our results of operations, cash flows and financial condition.

Our use of derivative instruments may adversely affect our results of operations.

Fluctuating commodity prices may affect our earnings and financing costs because our propane distribution and wholesale marketing operations use derivative instruments, including forwards, futures, swaps, puts, and calls, to hedge price risk. While we have risk management policies and operating procedures in place to control our exposure to risk, if we purchase derivative instruments that are not properly matched to our exposure, our results of operations, cash flows, and financial condition may be adversely affected.

Slowdowns in customer growth may adversely affect earnings and cash flows.

Our ability to increase gross margins in our regulated energy and unregulated propane distribution businesses is dependent upon growth in the residential construction market, adding new commercial and industrial customers and conversion of customers to natural gas, electricity or propane from other energy sources. Slowdowns in growth may adversely affect our gross margin, earnings and cash flows.

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Our businesses are capital intensive, and the increased costs and/or delays of capital projects may adversely affect our future earnings.

Our businesses are capital intensive and require significant investments in on-going infrastructure projects. Our ability to complete our infrastructure projects on a timely basis and manage the overall cost of those projects may be affected by the limited availability of the necessary materials and qualified vendors. Our future earnings could be adversely affected if we are unable to manage such capital projects effectively, or if full recovery of such capital costs is not permitted in future regulatory proceedings.

Our regulated energy business may be at risk if franchise agreements are not renewed.

Our regulated natural gas and electric distribution operations hold franchises in each of the incorporated municipalities that require franchise agreements in order to provide natural gas and electricity. Our natural gas and electric distribution operations are currently in negotiations for franchises with certain municipalities for new service areas and renewal of some existing franchises. Ongoing financial results would be adversely impacted from the loss of service to certain operating areas within our electric or natural gas territories in the event that franchise agreements were not renewed.

A strike, work stoppage or a labor dispute could adversely affect our operations.

We are party to collective bargaining agreements with labor unions at some of our Florida operations. A strike, work stoppage or a labor dispute with a union or employees represented by a union could cause interruption to our operations. If a strike, work stoppage or other labor dispute were to occur, our results could be adversely affected.

Accidents, natural disasters, severe weather (such as a major hurricane) and acts of terrorism could adversely impact earnings.

Inherent in energy transmission and distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions, sabotage and mechanical problems. Natural disasters and severe weather may damage our assets, cause operational interruptions and result in the loss of human life. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas, electricity and propane that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. The insurance industry may also be affected by natural disasters, severe weather and acts of terrorism, and as a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms, which could adversely affect our results of operations, financial condition and cash flows.

A security breach disrupting our operating systems and facilities or exposing confidential information may adversely affect our reputation, disrupt our operations and increase our costs.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions or generate facility shutdowns. If such an attack or security breach were to occur, our business, results of operations and financial condition could be adversely affected. Additionally, the protection of customer, employee and Company data is crucial to our operational security. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and have an adverse effect on our reputation, results of operations and financial condition. A breakdown or breach could also materially increase our costs of maintaining our system and protecting it against future breakdowns or breaches. We take reasonable precautions to safeguard our information systems from cyber-attacks and security breaches; however, there is no guarantee that the procedures implemented to protect against unauthorized access to our information systems are adequate to safeguard against all attacks and breaches.

REGULATORY, LEGAL AND ENVIRONMENTAL RISKS

Regulation of our businesses, including changes in the regulatory environment, may adversely affect our results of operations, cash flows and financial condition.

The Delaware, Maryland and Florida PSCs regulate our utility operations in those states. Eastern Shore is regulated by the FERC. The PSCs and the FERC set the rates that we can charge customers for services subject to their regulatory jurisdiction. Our ability to obtain timely future rate increases and rate supplements to maintain current rates of return depends on regulatory approvals, and there can be no assurance that our regulated operations will be able to obtain such approvals or maintain currently authorized rates of return. When our earnings from the regulated utilities exceed the authorized rate of return, the respective PSC, or the FERC in the case of Eastern Shore, may require us to reduce our rates charged to customers in the future.

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We are dependent upon construction of new facilities to support future growth in earnings in our natural gas and electric distribution and natural gas transmission operations.

Construction of new facilities required to support future growth is subject to various regulatory and developmental risks, including but not limited to: (i) our ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on terms that are acceptable to us; (ii) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (iii) inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (iv) lack of anticipated future growth in available natural gas and electricity supply; and (v) insufficient customer throughput commitments.

We are subject to operating and litigation risks that may not be fully covered by insurance.

Our operations are subject to the operating hazards and risks normally incidental to handling, storing, transporting, transmitting and delivering natural gas, electricity and propane to end users. From time to time, we are a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance coverage for our general liabilities in the amount of $51 million, which we believe is reasonable and prudent. However, there can be no assurance that such insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices.

We may face certain regulatory and financial risks related to pipeline safety legislation.

A number of legislative proposals to implement increased oversight over natural gas pipeline operations and facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities are pending at the federal level. Additional operating expenses and capital expenditures may be necessary to remain in compliance with the increased federal oversight that may result from such proposals. If such legislation is adopted and we incur additional expenses and expenditures, our financial condition, results of operations and cash flows could be adversely affected, particularly if we are not authorized through the regulatory process to recover from customers some or all of these costs and our authorized rate of return.

Costs of compliance with environmental laws may be significant.

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These evolving laws and regulations may require expenditures over a long period of time to control environmental effects at our current and former operating sites, especially former MGP sites. Compliance with these legal obligations requires us to commit capital. If we fail to comply with environmental laws and regulations, even if such failure is caused by factors beyond our control, we may be assessed civil or criminal penalties and fines.

To date, we have been able to recover, through regulatory rate mechanisms, the costs associated with the remediation of former MGP sites. However, there is no guarantee that we will be able to recover future remediation costs in the same manner or at all. A change in our approved rate mechanisms for recovery of environmental remediation costs at former MGP sites could adversely affect our results of operations, cash flows and financial condition.

Further, existing environmental laws and regulations may be revised, or new laws and regulations seeking to protect the environment may be adopted and be applicable to us. Revised or additional laws and regulations could result in additional operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable.

Derivatives legislation and the implementation of related rules could have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Act regulates derivative transactions, which include certain instruments used in our risk management activities. The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, subject to certain exceptions for entities that use swaps to hedge or mitigate commercial risk. Although the Dodd-Frank Act includes significant new provisions regarding the regulation of derivatives, the impact of those requirements will not be known definitively until regulations have been adopted and fully implemented by both the SEC and the Commodities Futures Trading Commission, and market participants establish registered clearing facilities under those regulations. Although we may qualify for exceptions, its derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase our transaction costs, make it more difficult for us to enter into hedging transactions on favorable terms or affect the number and/or creditworthiness of available counterparties. Our inability to enter into hedging transactions on favorable terms, or at all, could increase operating expenses and increase exposure to risks of adverse changes in commodity prices, which could adversely affect the predictability of cash flows.

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Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.
There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress, or similar legislation by states, or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas and propane or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

ITEM 1B. UNRESOLVED STAFF COMMENTS.
None.

ITEM 2. PROPERTIES.
Key Properties
We own approximately 1,299 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in New Castle, Kent and Sussex Counties, Delaware; and Cecil, Caroline, Dorchester, Wicomico and Worcester Counties, Maryland. We own 2,717 miles of natural gas distribution mains (and related equipment) in Nassau, Polk, Osceola, Citrus, DeSoto, Liberty, Hillsborough, Holmes, Jackson, Gadsden, Gilchrist, Union, Washington, Pasco, Suwannee, Palm Beach, Broward, Martin, Marion, Seminole and Volusia Counties, Florida. In addition, we have adequate gate stations to handle receipt of the gas into each of the distribution systems. We also own facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.
Through Eastern Shore, we own and operate approximately 442 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Daleville and Honey Brook, Pennsylvania; and Hockessin, Delaware, to 92 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland. Through Peninsula Pipeline, we own and operate approximately 31 miles of transmission pipeline in Suwannee, Indian River and Palm Beach counties, Florida. We also own approximately 45 percent of the 16-mile pipeline extending from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The remaining 55 percent of the pipeline is owned by Peoples Gas.
Through FPU, we own and operate 20 miles of electric transmission line located in Nassau County, Florida and 879 miles of electric distribution line in Jackson, Liberty, Calhoun and Nassau Counties, Florida.
We own 417 miles of underground propane distribution mains in Delaware; Dorchester, Princess Ann, Queen Anne's, Somerset, Talbot, Wicomico and Worcester Counties, Maryland; Chester and Delaware Counties, Pennsylvania; and Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.
We own bulk propane storage facilities, with an aggregate capacity of approximately 3.0 million gallons, at 33 plant facilities in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by us. In Florida, we own bulk propane storage facilities with an aggregate capacity of approximately 870,000 gallons at 17 plant facilities. Xeron does not own physical storage facilities or equipment to transport propane; however, it leases propane storage and pipeline capacity from non-affiliated third parties.
We own offices and operate facilities in the following locations: Worcester, Wicomico, Dorchester, Talbot, Cecil and Somerset Counties, Maryland; Kent and Sussex Counties, Delaware; Accomack County, Virginia; and Palm Beach, Volusia, Levy, Martin, Jackson, Broward, Nassau, Brevard, Alachua, Hendry, Okeechobee, and Polk Counties, Florida.
Lien

All of the assets owned by FPU are subject to a lien in favor of the holders of its first mortgage bond securing its indebtedness under its Mortgage Indenture and Deed of Trust. FPU owns offices and operates facilities in the following locations: Palm Beach, Volusia, Levy, Martin, Jackson, Broward, Nassau, Brevard, Alachua, Hendry and Okeechobee Counties, Florida. The FPU assets subject to the lien also include: 1,865 miles of natural gas distribution mains (and related equipment) in its service areas; 20 miles of electric transmission line located in Nassau County, Florida; 879 miles of electric distribution line located in Jackson, Liberty, Calhoun and Nassau Counties in Florida; 17 plant facilities with a total capacity of 870,000 gallons, located in south and central

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Florida; and 59 miles of underground propane distribution mains in Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

ITEM 3. LEGAL PROCEEDINGS.

LEGAL PROCEEDINGS

As disclosed in Item 8, Financial Statements and Supplementary Data (see Note 20, Other Commitments and Contingencies, in the Consolidated Financial Statements), we are involved in various legal actions and claims arising in the normal course of business. We are also involved in certain administrative proceedings before various governmental or regulatory agencies concerning rates. In the opinion of management, the ultimate disposition of these current proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT.

Set forth below are the names, ages, and positions of our executive officers with their recent business experience. The age of each officer is as of the filing date of this report.

Name	Age	Position
Michael P. McMasters	56	President (March 2010 - present) Chief Executive Officer (January 2011 - present) Director (March 2010 - present) Executive Vice President (September 2008 - February 2010) Chief Operating Officer (September 2008 - December 2010) Chief Financial Officer (January 1997 - September 2008) Mr. McMasters also previously served as Senior Vice President, Vice President, Treasurer, Director of Accounting and Rates, and Controller.
Beth W. Cooper	48	Senior Vice President (September 2008 - present) Chief Financial Officer (September 2008 - present) Corporate Secretary (June 2005 - March 2015) Vice President (June 2005 - September 2008) Treasurer (March 2003 - May 2012) Ms. Cooper also previously served as Assistant Vice President, Assistant Treasurer, Assistant Secretary, Director of Internal Audit, and Director of Strategic Planning.
Elaine B. Bittner	45	Senior Vice President of Strategic Development (May 2013 - present) Vice President of Strategic Development (June 2010 - May 2013) Vice President, Eastern Shore (May 2005 - June 2010) Ms. Bittner also previously served as Director of Eastern Shore; Director of Customer Services and Regulatory Affairs for Eastern Shore; Director of Environmental Affairs and Environmental Engineer.
Stephen C. Thompson	54	Senior Vice President (September 2004 - present) President, Eastern Shore (January 1997 - present) Vice President (May 1997 - September 2004)

		Mr. Thompson also previously served as Director of Gas Supply and Marketing for Eastern Shore; Superintendent of Eastern Shore; and Regional Manager for Florida distribution operations. President of Florida Public Utilities Company (June 2010 - present)
Jeffry M. Householder	57	Prior to joining Chesapeake, Mr. Householder operated a consulting practice that provided business development and regulatory services to utilities, propane retailers and industrial clients.

PART II

ITEM 5. MARKET FOR THE REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

COMMON STOCK PRICE RANGES, COMMON STOCK DIVIDENDS AND SHAREHOLDER INFORMATION:

At February 28, 2015, there were 2,341 holders of record of Chesapeake common stock. Our common stock is listed on the NYSE under the symbol “CPK.” The high, low and closing prices of our common stock and dividends declared per share for each calendar quarter during 2014 and 2013, adjusted for the three-for-two stock split effected as a stock dividend on September 9, 2014, were as follows:

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2014					
	March 31	$43.01	$37.49	$42.11	$0.257
	June 30	$47.69	$39.77	$47.55	$0.270
	September 30	$48.73	$39.28	$41.66	$0.270
	December 31	$52.66	$40.88	$49.66	$0.270
2013					
	March 31	$33.59	$30.56	$32.70	$0.243
	June 30	$37.24	$32.17	$34.33	$0.257
	September 30	$40.05	$33.89	$34.99	$0.257
	December 31	$40.78	$33.69	$40.01	$0.257

We have paid a cash dividend to common stock shareholders for 54 consecutive years. Dividends are payable at the discretion of our Board of Directors. Future payment of dividends, and the amount of these dividends, will depend on our financial condition, results of operations, capital requirements, and other factors. We declared quarterly cash dividends on our common stock in 2014 and 2013, totaling $1.067 per share and $1.013 per share, respectively.

Indentures to our long-term debt contain various restrictions which limit our ability to pay dividends. Each of our unsecured senior notes contains a “Restricted Payments” covenant. The most restrictive covenants of this type are included within the 5.68 percent and 6.43 percent Senior Notes, due June 30, 2026 and May 2, 2028, respectively. The covenant provides that we cannot pay or declare any dividends or make any other Restricted Payments (such as dividends) in excess of the sum of $10.0 million plus consolidated net income of the Company accrued on and after January 1, 2003. As of December 31, 2014, our cumulative consolidated net income base was $243.8 million, offset by Restricted Payments of $80.9 million, leaving $162.9 million of cumulative net income free of restrictions.

FPU’s first mortgage bonds due in 2022 contain a similar restriction that limits the payment of dividends by FPU. The bonds provide that FPU cannot make dividend or other restricted payments in excess of the sum of $2.5 million plus FPU’s consolidated net income accrued on and after January 1, 1992. As of December 31, 2014, FPU had a cumulative net income base of $104.1 million, offset by restricted payments of $37.6 million, leaving $66.5 million of cumulative net income of FPU free of restrictions based on this covenant.

No securities were sold during the year 2014 that were not registered under the Securities Act of 1933, as amended.

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PURCHASES OF EQUITY SECURITIES BY THE ISSUER

The following table sets forth information on purchases by or on behalf of Chesapeake of shares of its common stock during the quarter ended December 31, 2014.

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]
October 1, 2014 through October 31, 2014 [1]	365	$41.76	—	—
November 1, 2014 through November 30, 2014	—	—	—	—
December 1, 2014 through December 31, 2014	—	—	—	—
Total	365	$41.76	—	—

(1) In October, Chesapeake purchased shares of common stock on the open market for the purpose of reinvesting the dividend on shares held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Non-Qualified Deferred Compensation Plan. The Non-Qualified Deferred Compensation Plan is discussed in detail in Item 8, Financial Statements and Supplementary Data (see Note 16, Employee Benefit Plans, in the Consolidated Financial Statements). During the quarter, 365 shares were purchased through the reinvestment of dividends.

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

Discussion of our compensation plans, for which shares of Chesapeake common stock are authorized for issuance, is included in the portion of the Proxy Statement captioned “Equity Compensation Plan Information” to be filed no later than March 31, 2015, in connection with our Annual Meeting to be held on or about May 6, 2015, and is incorporated herein by reference.

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COMMON STOCK PERFORMANCE GRAPH

The stock performance graph and table below compares cumulative total stockholder return on our common stock during the five fiscal years ended December 31, 2014, with the cumulative total stockholder return of the S&P 500 Index and the cumulative total stockholder return of select peers, which include the following companies: AGL Resources, Inc., Atmos Energy Corporation, Delta Natural Gas Company, Inc., The Laclede Group, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc., RGC Resources, Inc., South Jersey Industries, Inc., and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2009 in our common stock and in each of the foregoing indices and assumes reinvested dividends. The comparisons in the graph below are based on historical data and are not intended to forecast the possible future performance of our common stock.

	2009	2010	2011	2012	2013	2014
Chesapeake	$100	$134	$144	$155	$211	$267
Industry Index	$100	$117	$136	$133	$159	$224
S&P 500	$100	$115	$117	$136	$179	$204

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ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,		
	2014	2013	2012
Operating [(1)]			
(in thousands)			
Revenues			
Regulated Energy	$300,442	$264,637	$246,208
Unregulated Energy	184,961	166,723	133,049
Other	13,431	12,946	13,245
Total revenues	$498,834	$444,306	$392,502
Operating income			
Regulated Energy	$50,451	$50,084	$46,999
Unregulated Energy	11,723	12,353	8,355
Other	105	297	1,281
Total operating income	$62,279	$62,734	$56,635
Net income from continuing operations	$36,092	$32,787	$28,863
Assets			
(in thousands)			
Gross property, plant and equipment	$883,131	$805,394	$697,159
Net property, plant and equipment	$689,762	$631,246	$541,781
Total assets	$904,469	$837,522	$733,746
Capital expenditures [(1)]	$98,057	$108,039	$78,210
Capitalization			
(in thousands)			
Stockholders' equity	$300,322	$278,773	$256,598
Long-term debt, net of current maturities	158,486	117,592	101,907
Total capitalization	$458,808	$396,365	$358,505
Current portion of long-term debt	9,109	11,353	8,196
Short-term debt	88,231	105,666	61,199
Total capitalization and short-term financing	$556,148	$513,384	$427,900

(1) These amounts exclude the results of distributed energy and water services due to their reclassification to discontinued operations. We closed our distributed energy operation in 2007. All assets of the water businesses were sold in 2004 and 2003. These amounts also include accruals for capital expenditures that we have incurred for each reporting period.

(2) These amounts include the financial position and results of operation of FPU for the period from the merger (October 28, 2009) to December 31, 2009. These amounts also include the effects of acquisition accounting and issuance of Chesapeake common shares as a result of the merger.

(3) ASC 718, Compensation—Stock Compensation, and ASC 715, Compensation—Retirement Plans, were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

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2011	2010	2009[2]	2008	2007	2006 [3]	2005
$256,226	$269,438	$138,671	$116,123	$128,566	$124,438	$124,445
149,586	146,793	119,973	161,290	115,190	94,320	90,995
12,215	11,315	10,141	14,030	14,530	12,442	14,045
$418,027	$427,546	$268,785	$291,443	$258,286	$231,200	$229,485
$43,911	$43,267	$26,668	$23,833	$21,739	$18,618	$16,278
9,619	8,150	8,390	3,600	5,244	3,650	4,167
175	513	(1,322)	1,046	1,131	1,064	1,476
$53,705	$51,930	$33,736	$28,479	$28,114	$23,332	$21,921
$27,622	$26,056	$15,897	$13,607	$13,218	$10,748	$10,699
$625,488	$584,385	$543,905	$381,689	$352,838	$325,836	$280,345
$487,704	$462,757	$436,587	$280,671	$260,423	$240,825	$201,504
$709,066	$670,993	$615,811	$385,795	$381,557	$325,585	$295,980
$44,431	$46,955	$26,294	$30,844	$30,142	$49,154	$33,423
$240,780	$226,239	$209,781	$123,073	$119,576	$111,152	$84,757
110,285	89,642	98,814	86,422	63,256	71,050	58,991
$351,065	$315,881	$308,595	$209,495	$182,832	$182,202	$143,748
8,196	9,216	35,299	6,656	7,656	7,656	4,929
34,707	63,958	30,023	33,000	45,664	27,554	35,482
$393,968	$389,055	$373,917	$249,151	$236,152	$217,412	$184,159

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	For the Year Ended December 31,		
	2014	2013	2012
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [(1) (6)]	$2.48	$2.27	$2.01
Diluted earnings per share from continuing operations [(1) (6)]	$2.47	$2.26	$1.99
Return on average equity from continuing operations [(1)]	12.2 %	12.2 %	11.6 %
Common equity / total capitalization	65.5 %	70.3 %	71.6 %
Common equity / total capitalization and short-term financing	54.0 %	54.3 %	60.0 %
Book value per share [(6)]	$20.59	$19.28	$17.82
Market price:			
High	$52.660	$40.780	$32.613
Low	$37.493	$30.560	$26.593
Close	$49.660	$40.013	$30.267
Average number of shares outstanding [(6)]	14,551,308	14,430,962	14,379,216
Shares outstanding at year-end [(6)]	14,588,711	14,457,345	14,396,248
Registered common shareholders	2,329	2,345	2,396
Cash dividends declared per share	$1.07	$1.01	$0.96
Dividend yield (annualized) [(4)]	2.2 %	2.6 %	3.2 %
Payout ratio from continuing operations [(1) (5)]	43.0 %	44.6 %	47.8 %
Additional Data			
Customers			
Natural gas distribution	141,227	138,210	124,015
Electric distribution	31,272	31,151	31,066
Propane distribution	53,272	51,988	49,312
Volumes			
Natural gas deliveries (in Dts)	77,623,201	74,117,121	66,784,690
Electric Distribution (in MWHs)	643,332	649,025	670,998
Propane distribution (in thousands of gallons)	53,525	48,511	37,438
Heating degree-days (Delmarva Peninsula)			
Actual HDD	4,826	4,638	3,936
10-year average HDD (normal)	4,483	4,454	4,491
Heating degree-days (Florida)			
Actual HDD	888	671	633
10-year average HDD (normal)	856	885	915
Cooling degree-days (Florida)			
Actual CDD	2,705	2,750	2,871
10-year average CDD (normal)	2,768	2,750	2,756
Propane bulk storage capacity (in thousands of gallons)	3,833	3,566	3,400
Total employees [(1)]	753	842	738

(1) These amounts exclude the results of distributed energy and water services due to their reclassification to discontinued operations. We closed our distributed energy operation in 2007. All assets of the water businesses were sold in 2004 and 2003.

(2) These amounts include the financial position and results of operation of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009.

(3) ASC Topic 718, Compensation—Stock Compensation, and ASC Topic 715, Compensation—Retirement Plans, were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

(4)

Dividend yield (annualized) is calculated by multiplying the fourth quarter dividend by four (4), then dividing that amount by the closing common stock price at December 31.

(5) The payout ratio from continuing operations is calculated by dividing cash dividends declared per share (for the year) by basic earnings per share from continuing operations.

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

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2011	2010	2009[2]	2008	2007	2006 [3]	2005
$1.93	$1.83	$1.45	$1.33	$1.31	$1.19	$1.22
$1.91	$1.82	$1.43	$1.32	$1.29	$1.17	$1.21
11.6 %	11.6 %	11.2 %	11.2 %	11.5 %	11.0 %	13.2 %
68.6 %	71.6 %	68.0 %	58.7 %	65.4 %	61.0 %	59.0 %
61.1 %	58.2 %	56.1 %	49.4 %	50.6 %	51.1 %	46.0 %
$16.78	$15.84	$14.89	$12.02	$11.76	$11.08	$9.60
$29.687	$28.133	$23.333	$23.227	$24.833	$23.767	$23.853
$24.000	$18.673	$14.680	$14.620	$18.667	$18.600	$15.733
$28.900	$27.680	$21.367	$20.987	$21.233	$20.433	$20.533
14,333,699	14,211,831	10,969,980	10,217,772	10,114,562	9,048,693	8,754,695
14,350,959	14,286,293	14,091,471	10,240,682	10,166,115	10,032,126	8,824,649
2,481	2,482	2,670	1,914	1,920	1,978	2,026
$0.91	$0.87	$0.83	$0.81	$0.78	$0.77	$0.76
3.2 %	3.2 %	3.9 %	3.9 %	3.7 %	3.8 %	3.7 %
47.4 %	47.6 %	57.6 %	60.5 %	60.2 %	65.2 %	62.3 %
121,934	120,230	117,887	65,201	62,884	59,132	54,786
30,986	30,966	31,030	—	—	—	—
48,824	48,100	48,680	34,981	34,143	33,282	32,117
57,493,022	49,310,314	50,159,227	46,539,142	42,910,964	41,826,357	43,716,921
694,653	751,507	105,739	—	—	—	—
37,387	39,807	32,546	27,956	29,785	24,243	26,178
4,221	4,831	4,729	4,431	4,504	3,931	4,792
4,499	4,528	4,462	4,401	4,376	4,372	4,436
753	1,501	911	—	—	—	—
920	863	849	—	—	—	—
2,858	2,859	2,770	—	—	—	—
2,718	2,695	2,687	—	—	—	—
3,351	3,041	3,042	2,471	2,441	2,315	2,315
711	734	757	448	445	437	423

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This section provides management's discussion of Chesapeake and its consolidated subsidiaries, with specific information on results of operations, liquidity and capital resources, as well as discussion of how certain accounting principles affect our financial statements. It includes management's interpretation of our financial results and our operating segments, the factors affecting these results, the major factors expected to affect future operating results as well as investment and financing plans. This discussion should be read in conjunction with our Consolidated Financial Statements and notes thereto in Item 8, Financial Statements and Supplementary Data.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A, Risk Factors. They should be considered in connection with forward-looking statements contained in this report, or otherwise made by or on behalf of us, since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

The following discussions and those later 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 us under our allowed rates for regulated energy operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring our business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Shares and per share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, which was effected in the form of a stock dividend and distributed on September 8, 2014. Unless otherwise noted, earnings per share information is presented on a diluted basis.

INTRODUCTION

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

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

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through leveraging our community gas system services and our bulk delivery capabilities;
- expanding both our regulated energy and unregulated energy businesses through strategic acquisitions;
- utilizing our expertise across our various businesses to improve overall performance;
- pursuing and entering new unregulated energy markets and business lines that will complement our existing strategy and operating units;
- enhancing marketing channels to attract new customers;
- providing reliable and responsive customer service to existing customers so they become our best promoters;
- engaging our customers through a distinctive service excellence initiative;
- developing and retaining a high performing team that advances our goals;
- empowering and engaging our employees at all levels to live our brand and vision;

- demonstrating community leadership and engaging our local communities and governments in a cooperative and mutually beneficial way;
- maintaining a capital structure that enables us to access capital as needed;

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- maintaining a consistent and competitive dividend for shareholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

CRITICAL ACCOUNTING POLICIES

We prepare our financial statements in accordance with GAAP. Application of these accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingencies during the reporting period. We base our estimates on historical experience and on various assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Since most of our businesses are regulated and the accounting methods used by these businesses must comply with the requirements of the regulatory bodies, the choices available are limited by these regulatory requirements. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from estimates. Management believes that the following policies require significant estimates or other judgments of matters that are inherently uncertain. These policies and their application have been reviewed by our Audit Committee.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with FASB ASC Topic 980, Regulated Operations, and consequently, the accounting principles applied by our regulated energy businesses differ in certain respects from those applied by the unregulated businesses. Costs are deferred when there is a probable expectation that they will be recovered in future revenues as a result of the regulatory process. As more fully described in Item 8, Financial Statements and Supplementary Data (see Note 2, Summary of Significant Accounting Policies, in the Consolidated Financial Statements), we have recorded regulatory assets of $87.1 million and regulatory liabilities of $46.7 million at December 31, 2014. If we were required to terminate the application of ASC Topic 980, we would be required to recognize all such deferred amounts as a charge or a credit to earnings, net of applicable income taxes. Such an adjustment could have a material effect on our results of operations.

Valuation of Environmental Liabilities and Related Regulatory Assets

As more fully described in Item 8, Financial Statements and Supplementary Data (see Note 19, Environmental Commitments and Contingencies, in the Consolidated Financial Statements), we are currently participating in the investigation, assessment or remediation of six former MGP sites for which we have regulatory approval to recover through rates the estimated costs of remediation and related activities. We were recently notified by DNREC in January 2015 regarding groundwater contamination at a different former MPG site and have also been in discussions with the MDE regarding another former MGP site. Amounts have been recorded as environmental liabilities based on estimates of future costs to remediate these sites, which are provided by independent consultants. At December 31, 2014, we had $10.5 million in environmental liabilities, representing our estimate of such future costs. We have also recorded regulatory and other assets to reflect future recovery of those costs in rates and had $4.7 million of such assets at December 31, 2014, representing the amount of our environmental remediation costs to be recovered in future rates. There is uncertainty in these amounts, as the EPA, or other applicable state environmental authority, may not have selected the final remediation methods. In addition, there is uncertainty with regard to amounts that may be recovered from other potentially responsible parties.

Derivatives

We use derivative and non-derivative instruments to manage the risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. We also use derivative instruments to engage in propane wholesale marketing activities. We continually monitor the use of these instruments to ensure compliance with our risk management policies and account for them in accordance with the appropriate GAAP, such that every derivative instrument is recorded as either an asset or a liability measured at its fair value. It also requires that changes in the derivatives' fair value are recognized in the current period earnings unless specific hedge accounting criteria are met. If these instruments do not meet the definition of derivatives or are considered “normal purchases and sales,” they are accounted for on an accrual basis of accounting.

Additionally, GAAP also requires us to classify the derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair value of the assets and liabilities and their placement within the fair value hierarchy.

During the last three years, we had the following derivative assets and liabilities:

- Propane forward contracts entered into by Xeron; and

•Propane put options, call options and swap agreements entered into by Sharp.

We determined that certain propane put options, call options and swap agreements met the specific hedge accounting criteria. At December 31, 2014, we elected to discontinue hedge accounting on the swap agreements, which were previously accounted for as cash flow hedges. The discontinuation of hedge accounting resulted in recognition in current period earnings of the previously unrealized losses from these agreements. We also determined that our contracts for the purchase or sale of natural gas, electricity and propane either did not meet the definition of derivatives as they did not have a minimum requirement to purchase/sell or were considered “normal purchases and sales,” as they provided for the purchase or sale of natural gas, electricity or propane to be delivered in quantities that we expect to use or sell over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

As of December 31, 2014, we recorded $1.1 million and $1.0 million of derivative assets and liabilities, respectively. As of December 31, 2013, we recorded $385,000 and $127,000 of derivative assets and liabilities, respectively.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of each state in which we operate. Customers’ base rates may not be changed without formal approval by these PSCs. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. Eastern Shore’s revenues are based on rates approved by the FERC. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

For regulated deliveries of natural gas, propane and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters, such as community gas system customers and natural gas marketing customers, whose billing cycles do not coincide with the accounting periods.

We record trading activity for open propane wholesale marketing contracts on a net mark-to-market basis in the consolidated statement of income. For propane bulk delivery customers without meters we record revenue in the period the products are delivered and/or services are rendered.

Each of our natural gas distribution operations in Delaware and Maryland, our bundled natural gas distribution service in Florida and our electric distribution operation in Florida has a fuel cost recovery mechanism. This mechanism provides a method of adjusting billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to industrial interruptible customers on our natural gas distribution systems to compete with the price of alternative fuel that they can use. Neither we, nor any of our interruptible customers, are contractually obligated to deliver or receive natural gas on a firm service basis.

Allowance for Doubtful Accounts

An allowance for doubtful accounts is recorded against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect based upon our collections experience, the condition of the overall economy and our assessment of our customers’ inability or reluctance to pay. If circumstances change, however, our estimate of the recoverability of accounts receivable may also change. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Asset Impairment

We periodically evaluate whether events or circumstances have occurred which indicate that long-lived assets may not be recoverable. We also test goodwill for impairment at least annually in December of each year. When events or circumstances indicating impairment are present, we record an impairment loss equal to the excess of the assets' carrying value over its fair value, if any. At December 31, 2014, we recorded a non-cash, pre-tax impairment charge of $6.5 million related to uncertainty around the implementation of a customer billing system. This impairment charge represents all of the capitalized costs associated with this project. We are engaged in negotiations with the system vendor regarding the implementation, and are considering several options to recover these costs including regulatory proceedings. The outcome cannot be predicted at this time. We will record a gain contingency if and when any recovery from the vendor is realizable or establish a regulatory asset when future recovery through rates is probable. We also recorded a non-cash, pre-tax impairment charge of $412,000 related to the impairment of goodwill and intangible assets associated with the 2013 acquisition of certain assets by Austin Cox.

Pension and Other Postretirement Benefits

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on the pension costs and liabilities. The assumed discount rates, the assumed health care cost trend rates and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. Additional information is presented in Item 8, Financial Statements and Supplementary Data (See Note 16, Employee Benefit Plans, in the Consolidated Financial Statements), including plan asset investment allocation, estimated future benefit payments, general descriptions of the plans, significant assumptions, the impact of certain changes in assumptions, and significant changes in estimates.

Actuarial assumptions affecting 2014 include expected long-term rates of return on plan assets of 6.0 percent and 7.0 percent for Chesapeake's pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake's and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as Moody's Aa bond index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected lives of the plans and the availability of the lump-sum payment option. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $18,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $22,000.

The mortality assumption used for our pension and postretirement plans is based on the actuarial table that is most reflective of the expected mortality of the plan participants and reviewed periodically. We adopted a new mortality table (RP2014), which was developed by the Society of Actuaries and published in 2014.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $134,000 and would not have an impact on the postretirement and Chesapeake SERP because these plans are not funded.

The health care inflation rate for 2014 used to calculate the benefit obligation is 5 percent for medical and 6 percent for prescription drugs for the Chesapeake Postretirement Plan; and 5.5 percent for the FPU Medical Plan. A one–percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately $380,000 as of December 31, 2014, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2014 by approximately $14,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $302,000 as of December 31, 2014, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2014 by approximately $11,000.

Tax-related Contingency

We account for uncertainty in income taxes in the financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and estimable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss, assuming the proper inquiries are made by tax authorities.

As of December 31, 2014 and 2013, we recorded a total liability of $100,000 and $300,000, respectively, associated with unrecognized income tax benefits. As of December 31, 2014 and 2013, we recorded a total liability of $724,000 and $1.0 million, respectively, related to taxes other than income.

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OVERVIEW AND HIGHLIGHTS

(in thousands except per share) For the Year Ended December 31,	2014	2013	Increase (decrease)	2013	2012	Increase (decrease)
Business Segment:						
Regulated Energy	$50,451	$50,084	$367	$50,084	$46,999	$3,085
Unregulated Energy	11,723	12,353	(630)	12,353	8,355	3,998
Other	105	297	(192)	297	1,281	(984)
Operating Income	62,279	62,734	(455)	62,734	56,635	6,099
Gains from sale of businesses	7,139	—	7,139	—	—	—
Other Income	101	372	(271)	372	271	101
Interest Charges	9,482	8,234	1,248	8,234	8,747	(513)
Pre-tax Income	60,037	54,872	5,165	54,872	48,159	6,713
Income Taxes	23,945	22,085	1,860	22,085	19,296	2,789
Net Income	$36,092	$32,787	$3,305	$32,787	$28,863	$3,924
Earnings Per Share of Common Stock						
Basic	$2.48	$2.27	$0.21	$2.27	$2.01	$0.26
Diluted	$2.47	$2.26	$0.21	$2.26	$1.99	$0.27

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2014 compared to 2013

Our net income increased by approximately $3.3 million or $0.21 per share (diluted) in 2014, compared to 2013. Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2013 Reported Results	$54,872	$32,787	$2.26
Adjusting for unusual items:			
Gains on sale of businesses	7,139	4,266	0.29
Asset impairment charges	(6,880)	(4,111)	(0.28)
Weather impact	2,799	1,672	0.11
Regulatory recovery of litigation-related costs in 2013	(1,494)	(893)	(0.06)
Accrual for additional taxes other than income in 2013	990	592	0.04
One-time sales tax expense recorded by Sandpiper in conjunction with the 2013 ESG acquisition	726	434	0.03
	3,280	1,960	0.13
Increased (Decreased) Gross Margins:			
Major projects (see Major Project Highlights table)			
Service expansions	5,591	3,341	0.23
Contribution from Sandpiper	5,544	3,313	0.23
GRIP	2,862	1,710	0.12
Other natural gas growth	2,671	1,596	0.11
Increased wholesale propane sales	1,391	831	0.06
FPU electric base rate increase	1,269	758	0.05
	19,328	11,549	0.80
Increased Other Operating Expenses:			
Higher payroll and benefits costs	(5,164)	(3,085)	(0.21)
Expenses from acquisitions	(3,526)	(2,107)	(0.14)
Higher depreciation, asset removal and property tax costs due to new capital investments	(2,842)	(1,698)	(0.12)
Higher facility maintenance and service contractor costs	(2,735)	(1,634)	(0.11)
Larger accruals for incentive bonuses	(1,356)	(810)	(0.06)
Transaction costs	(760)	(454)	(0.03)
	(16,383)	(9,788)	(0.67)
Interest Charges	(1,247)	(745)	(0.05)
Net Other Changes	187	329	—
Year ended December 31, 2014 Reported Results	$60,037	$36,092	$2.47

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2013 compared to 2012

Our net income increased by approximately $3.9 million, or $0.26 per share (diluted) in 2013, compared to 2012. Key variances included:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2012 Reported Results	$48,159	$28,863	$2.00
Adjusting for unusual items:			
Weather impact (due primarily to significantly warmer-than-normal weather in 2012)	3,399	2,037	0.14
Regulatory recovery of litigation-related costs	1,494	895	0.06
Accrual for additional taxes other than income	(990)	(593)	(0.04)
One-time sales tax expensed by Sandpiper associated with the acquisition	(726)	(435)	(0.03)
	3,177	1,904	0.13
Increased (Decreased) Gross Margins:			
Major projects (see Major Project Highlights table)			
Contribution from Sandpiper	4,432	2,656	0.18
Service expansions	3,710	2,223	0.15
Higher propane margins	3,163	1,896	0.13
Contribution from other new acquisitions	2,016	1,208	0.08
Other natural gas growth	1,824	1,094	0.08
Propane wholesale marketing	(1,137)	(681)	(0.05)
	14,008	8,396	0.57
Increased Other Operating Expenses:			
Expenses from acquisitions	(5,309)	(3,182)	(0.22)
Higher payroll and benefits costs	(2,407)	(1,443)	(0.10)
Increased incentive bonuses	(2,002)	(1,200)	(0.08)
Higher depreciation, asset removal and property tax costs due to new capital investments	(1,555)	(932)	(0.06)
	(11,273)	(6,757)	(0.46)
Net Other Changes	801	381	0.02
Year ended December 31, 2013 Reported Results	$54,872	$32,787	$2.26

SUMMARY OF KEY FACTORS

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

Major Projects

Acquisition

In May 2013, we completed the purchase of the operating assets of ESG. Approximately 11,000 residential and commercial underground propane distribution system customers acquired in this transaction are now being served by Sandpiper under the tariff approved by the Maryland PSC. We have begun to convert some of the former ESG customers to natural gas distribution service, and we are evaluating the potential conversion of others. This acquisition was accretive to earnings per share in the first full year of operations, generating $0.20 in additional earnings per share. We generated $5.5 million in additional gross margin and incurred $2.5 million in additional other operating expenses from Sandpiper for the year ended December 31, 2014. Additionally, in the second quarter of 2013, we recorded $726,000 in a one-time sales tax expense associated with the acquisition of ESG.

Service Expansions

During 2013, Eastern Shore, our interstate pipeline subsidiary, commenced new natural gas transmission services to local distribution utilities and industrial customers in Delaware and Maryland. These new services generated additional gross margin of $2.7 million for the year ended December 31, 2014, compared to 2013.

On October 1, 2014, Eastern Shore commenced a new lateral service to an industrial customer facility in Kent County, Delaware. This service commenced after construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility. This new service, which generated $463,000 of gross margin for the year ended December 31, 2014, is expected to generate $1.8 million of gross margin in 2015 and annual gross margin of approximately $1.2 million to $1.8 million during the 37-year service period.

During 2014, Eastern Shore executed a one-year contract with another industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of additional transmission service from April 2014 to April 2015, which was subsequently amended to provide 55,580 Dts/d of service to August 2017. This contract generated gross margin of $1.9 million for the year ended December 31, 2014, and is expected to generate $2.2 million of gross margin in 2015.

In August 2013, Peninsula Pipeline, our intrastate natural gas transmission subsidiary, commenced a new firm transportation service in Indian River County, Florida for an unaffiliated utility. This new service generated $490,000 in additional gross margin in 2014 compared to 2013.

Other Natural Gas Growth

In addition to these service expansions, the natural gas distribution operations on the Delmarva Peninsula and in Florida generated $2.8 million of additional gross margin in the year ended December 31, 2014 compared to the same period in 2013, due to increases in the number of residential, commercial and industrial customers served. These increases are due primarily to a three percent increase in residential customers on the Delmarva Peninsula, excluding customers added as a part of the Sandpiper acquisition, and an increase in commercial and industrial customers in Florida.

Future Service Expansion Initiatives

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

In December 2014, Eastern Shore entered into a precedent agreement with an industrial customer in Kent County, Delaware, whereby the customer is committed to enter into a 20-year natural gas transmission service for 45,000 Dts/d for its new facility, upon the satisfaction of certain conditions. This new service will be provided as OPT ≤90 Service and is expected to generate at least $5.8 million of annual gross margin. In November 2014, Eastern Shore requested FERC authorization to construct 7.2 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware, which are estimated to cost approximately $30 million, to provide this service. Eastern Shore anticipates receiving FERC's authorization in 2015, with the service targeted to commence in the fourth quarter of 2015, following construction of the new facilities.

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

	Gross Margin for the Period Year Ended December 31,			Estimate for
	2014	2013	2012	2015
Acquisition:				
ESG acquisition being served by Sandpiper in Worcester County, Maryland (1)	$9,976	$4,432	$—	$10,402
Service Expansions				
Natural Gas Distribution:				
Long-term				
Sussex County, Delaware	$656	$670	$590	$674
Natural Gas Transmission:				
Short-term				
New Castle County, Delaware	$2,026	$398	$868	$2,418
Kent County, Delaware	—	1,158	—	—
Total Short-term	$2,026	$1,556	$868	$2,418
Long-term				
Sussex County, Delaware	$1,725	$1,437	$1,269	$1,725
New Castle County, Delaware	2,964	1,637	530	2,964
Nassau County, Florida	1,308	1,314	1,540	1,310
Worcester County, Maryland	547	417	90	547
Cecil County, Maryland	1,147	926	147	1,147
Indian River, Florida	840	350	—	840
Kent County, Delaware	3,122	437	—	4,504
Total Long-term	$11,653	$6,518	$3,576	$13,037
Total Service Expansions	$14,335	$8,744	$5,034	$16,129
Total Major Projects	$24,311	$13,176	$5,034	$26,531

(1) During the years ended December 31, 2014 and 2013, we incurred $5.6 million and $3.1 million, respectively, in other operating expenses related to Sandpiper.

The following table summarizes our estimated annualized margin from two future major expansion initiatives with executed contracts:

Project	Estimated Date of New Service	Estimated Annualized Margin
20-year OPT natural gas transmission service to an industrial customer in Kent County, Delaware	Fourth quarter of 2015	$5.8 million
Eight Flags CHP plant in Nassau County, Florida	Third quarter of 2016	$7.3 million

GRIP

In August 2012, the Florida PSC approved the GRIP, which is designed to recover capital and other program-related-costs, inclusive of a return on investment, related to the replacement of older pipes in our Florida service territories. We received approval to invest $75.0 million to replace qualifying distribution mains and services (any material other than coated steel or plastic). Since the program's inception in August 2012, we have invested $42.8 million, $24.3 million of which was invested during 2014. These investments generated additional gross margin of $2.9 million for the year ended December 31, 2014 compared to 2013. We expect to invest an additional $20.0 million through the GRIP in 2015.

Investing in Growth

We have continued to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation has initiated natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties in Maryland,

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which require the construction and conversion of distribution facilities, as well as the conversion of residential customers' appliances and equipment. To support this growth as well as future expansions, our Delmarva natural gas distribution operation has increased staffing. Resources have also been added in our corporate shared services departments to increase our overall capabilities to support sustained future growth. The additional staffing to support growth increased payroll expenses of our Regulated Energy segment by $2.0 million for the year ended December 31, 2014, compared to 2013. The Company expects to make additional investments in personnel, as needed, to further develop our capability to capitalize on future growth opportunities.

Weather and Consumption

Temperatures on the Delmarva Peninsula and in Florida during 2014 were colder than 2013, which positively affected our results in 2014. The following tables highlight the HDD and CDD information for the years ended December 31, 2014, 2013 and 2012, and the gross margin variance resulting from weather fluctuations in those periods.

HDD and CDD Information

For the Periods Ended December 31,	2014	2013	Variance	2013	2012	Variance
Delmarva						
Actual HDD	4,826	4,638	188	4,638	3,936	702
10-Year Average HDD ("Normal")	4,483	4,454	29	4,454	4,491	(37)
Variance from Normal	343	184		184	(555)	
Florida						
Actual HDD	888	671	217	671	633	38
10-Year Average HDD ("Normal")	856	885	(29)	885	915	(30)
Variance from Normal	32	(214)		(214)	(282)	
Florida						
Actual CDD	2,705	2,750	(45)	2,750	2,871	(121)
10-Year Average CDD ("Normal")	2,768	2,750	18	2,750	2,756	(6)
Variance from Normal	(63)	—		—	115	

Gross Margin Variance attributed to Weather

(in thousands)	2014 vs. 2013	2014 vs. Normal	2013 vs. 2012	2013 vs. Normal
Delmarva				
Regulated Energy	$232	$765	$984	$493
Unregulated Energy	1,398	1,344	3,069	260
Florida				
Regulated Energy	877	145	(571)	(1,204)
Unregulated Energy	292	485	(83)	67
Total	$2,799	$2,739	$3,399	$(384)

Propane Prices

During 2014, lower retail propane margins on the Delmarva Peninsula decreased gross margin by $2.3 million compared to 2013. A significant increase in wholesale prices in late 2013 and early 2014 increased the Delmarva average propane inventory cost in 2014. Retail propane margins on the Delmarva Peninsula reverted to more normal levels during the first three quarters of 2014, compared to unusually high margins experienced in 2013. In addition, a rapid decline in wholesale prices in late 2014 resulted in lower margins as we recorded a lower-of-cost-or-market propane inventory valuation adjustment. We also discontinued hedge

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accounting on swap agreements to recognize the expected losses of those hedges in current year's earnings. Both the propane inventory valuation adjustment and discontinuation of hedge accounting were designed to reflect the value of our inventory and future purchase commitments at the current market value at year-end in order to avoid any expected losses in future periods.

Retail propane margins in Florida continued to increase during 2014 as local market conditions enabled the Florida propane distribution operation to maintain strong margins on its sales despite volatility in propane supply costs. Higher retail propane margins in Florida generated $1.9 million of additional gross margin for the year ended December 31, 2014, compared to 2013.

Wholesale propane sales increased, generating additional gross margin of $1.4 million for the year ended December 31, 2014, compared to 2013, due primarily to sales to an affiliate of ESG.

The trading profit from Xeron, which benefits from wholesale price volatility by entering into trading transactions, remained unchanged in 2014, compared to 2013. Xeron reported higher trading profit in early 2014, as a result of higher wholesale price volatility during the winter heating season, which increased trading activity and generated higher profits on executed trades. This was offset by lower profit during the second half of 2014 as a result of less price volatility.

Florida Electric Rate Case

On September 15, 2014, the Florida PSC approved a settlement agreement between FPU and the Florida Office of Public Counsel in FPU's base rate case filing, which provides, among other things, an increase in FPU's annual revenue requirement of $3.75 million and a rate of common equity return of 10.25 percent for FPU's electric distribution operation. The new rates are effective for all meter readings on or after November 1, 2014. Previously, the Florida PSC approved interim rate relief, effective for meter readings on or after August 10, 2014. The higher base rates in FPU's electric operation generated $1.3 million of additional gross margin for the year ended December 31, 2014.

Other Developments

On October 1, 2014, we completed the sale of BravePoint for approximately $12.0 million in cash. We recorded a pre-tax gain of approximately $6.7 million ($4.0 million after-tax) from this sale in the fourth quarter of 2014. We plan to reinvest the proceeds from this sale in our regulated and unregulated energy businesses.

At December 31, 2014, we recorded a non-cash, pre-tax impairment charge of $6.5 million related to uncertainty about the implementation of a customer billing system. This impairment charge represents the entire amount of the capitalized costs associated with this project. We are engaged in negotiations with the system vendor regarding the implementation, and are considering several options to recover these costs, including regulatory proceedings. The outcome cannot be predicted at this time. We will record a gain contingency if and when any recovery from the vendor is realizable or establish a regulatory asset if future recovery through rates is probable. We also recorded a non-cash, pre-tax impairment charge of $412,000 related to the impairment of goodwill and intangible assets associated with the 2013 acquisition by Austin Cox.

Subsequent Event

On January 30, 2015, we entered into a merger agreement to acquire Gatherco. Upon consummation of the transaction, Gatherco will merge into Aspire Energy, a newly formed, wholly-owned subsidiary of Chesapeake. At closing, we expect to issue 593,005 shares of our common stock, valued at $29.9 million, pay $27.6 million in cash and assume Gatherco's debt estimated to be $1.7 million. We expect to pay off this debt shortly after closing. Gatherco is a natural gas infrastructure company providing natural gas midstream services. Gatherco's assets include 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Gatherco provides natural gas gathering services and natural gas liquid processing services to over 300 producers and supplies natural gas to over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity which Gatherco manages under an operating agreement. The transaction is subject to approval by Gatherco's shareholders and is expected to close in the second quarter of 2015.

REGULATED ENERGY

For the Year Ended December 31, (in thousands)	2014	2013	Increase (decrease)	2013	2012	Increase (decrease)
Revenue	$300,442	$264,637	$35,805	$264,637	$246,208	$18,429
Cost of sales	134,560	118,817	15,743	118,817	111,402	7,415
Gross margin	165,882	145,820	20,062	145,820	134,806	11,014
Operations & maintenance	76,046	65,713	10,333	65,713	61,113	4,600
Asset impairment charges	6,449	—	6,449	—	—	—
Depreciation & amortization	21,915	19,822	2,093	19,822	18,653	1,169
Other taxes	11,021	10,201	820	10,201	8,041	2,160
Other operating expenses	115,431	95,736	19,695	95,736	87,807	7,929
Operating Income	$50,451	$50,084	$367	$50,084	$46,999	$3,085

2014 compared to 2013

Operating income for the Regulated Energy segment increased by $367,000 to $50.5 million for 2014, compared to 2013. An increase in gross margin of $20.1 million was partially offset by the $6.4 million asset impairment charge in 2014 related to uncertainty around the implementation of a customer billing system and an increase in other operating expenses of $13.3 million. Excluding the impairment charge, operating income increased by $6.8 million.

Gross Margin

Items contributing to the year-over-year increase of $20.1 million, or 14 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the year ended December 31, 2013	$145,820
Factors contributing to the gross margin increase for the year ended December 31, 2014:	
Contributions from acquisitions	5,718
Service expansions	5,591
Additional revenue for GRIP in Florida	2,862
Other natural gas growth	2,671
Increased customer consumption—weather and other	1,432
Implementation of electric rates in Florida	1,269
Other	519
Gross margin for the year ended December 31, 2014	$165,882

Contributions from Acquisitions

Sandpiper generated $5.5 million of additional gross margin in 2014 due to the inclusion of a full year of operation (the acquisition of the operating assets of ESG by Sandpiper occurred in late May 2013). Also, the acquisition in December 2013 of certain operating assets of the City of Fort Meade, Florida, generated $174,000 of additional gross margin in 2014.

Service Expansions

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

- $2.1 million from long-term natural gas transmission services that commenced in November 2013 to industrial customers located in New Castle and Kent Counties, Delaware, which displaced short-term services provided to the same customers from May through October 2013.
- $1.9 million from a short-term contract with an existing industrial customer to provide an additional 50,000 Dts/d of natural gas transmission services from April 2014 to April 2015. This new service was subsequently extended to

August 2014 to provide 55,580 Dts/d of service. This short-term contract is expected to generate $2.2 million of gross margin in 2015.

- $1.1 million from other major service expansions completed in 2013 that facilitated new natural gas transmission and distribution services in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Indian River County, Florida.
- $463,000 from a new service to an industrial customer facility in Kent County, Delaware that commenced on October 1, 2014. This service required construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility, and is expected to generate annual gross margin of $1.2 million to $1.8 million.

Additional Revenue from GRIP in Florida

In 2014, FPU and Chesapeake's Florida division recorded $2.9 million in additional gross margin as a result of additional GRIP capital expenditures.

Other Natural Gas Growth

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

- $2.0 million from natural gas customer growth in Florida due primarily to new services to commercial and industrial customers.
- $788,000 from a three percent increase in residential customers, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operations.

Increased Customer Consumption—Weather and Other

In 2014, higher customer consumption due to colder temperatures on the Delmarva Peninsula and in Florida generated increased gross margin by approximately $1.1 million. Higher non-weather-related consumption generated additional gross margin of $322,000.

Implementation of Electric Rates in Florida

Our FPU electric distribution operation generated an additional gross margin of $1.3 million as a result of implementing interim and full rates as part of its base rate case filing.

Other Operating Expenses

The increase in other operating expenses, excluding impairment charges, was due primarily to: (a) $3.3 million in higher payroll and benefits costs to support growth, and a change in our vacation policy in 2013; (b) $2.5 million in other operating expenses associated with Sandpiper's operations; (c) $2.6 million in higher depreciation, amortization, asset removal costs and property taxes associated with capital investments to support growth and maintain system integrity; (d) $2.2 million in higher costs associated with facilities maintenance and service contractors; (e) the absence in 2014 of a one-time credit of $1.5 million in 2013 associated with the City of Marianna litigation cost recovery; and (f) $1.0 million of increased accruals for incentive bonuses as a result of strong financial performance. These increases in other operating expenses were partially offset by the non-recurrence of a sales tax expense of $726,000 in 2013 recorded in conjunction with the ESG acquisition.

2013 compared to 2012

Operating income for the Regulated Energy segment for 2013 was $50.1 million, an increase of $3.1 million, or seven percent. An increase in gross margin of $11.0 million was partially offset by an increase in other operating expenses of $7.9 million.

Gross Margin

Items contributing to the year-over-year increase of $11.0 million, or eight percent, in gross margin are listed in the following table:

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(in thousands)	
Gross margin for the year ended December 31, 2012	$134,806
Factors contributing to the gross margin increase for the year ended December 31, 2013:	
Contribution from Sandpiper	4,432
Service expansions	3,710
Other natural gas growth	1,824
Additional revenue for GRIP in Florida	724
Increased customer consumption—weather and other	455
Other	(131)
Gross margin for the year ended December 31, 2013	$145,820

Contribution from Sandpiper

In late May 2013, upon completion of the purchase of the ESG operating assets, Sandpiper began providing services to approximately 11,000 propane underground distribution system customers in Worcester County, Maryland under a new tariff approved by the Maryland PSC. Sandpiper generated $4.4 million of gross margin for the year ended December 31, 2013.

Service Expansions

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

- $1.5 million from expansions of natural gas transmission and distribution services completed in 2012 and 2013 in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau and Indian River Counties, Florida.
- $1.4 million from short-term natural gas transmission services from May to October 2013, Eastern Shore provided short-term transmission services to industrial customers located in New Castle and Kent Counties, Delaware by using existing system capacity. In November 2013, upon completion of construction of new facilities, these short-term contracts were replaced with long-term service contracts.
- $702,000 from long-term transmission services. In November 2013, Eastern Shore began providing long-term transmission services to industrial customers, which displaced the short-term services previously discussed. These long-term services are expected to generate $4.3 million of annual gross margin. They also displace an annualized gross margin of $1.1 million from an older contract, which expired in November 2012.

Other Natural Gas Growth

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

- $1.5 million from Florida customer growth. Our Florida natural gas distribution operation generated additional gross margin due primarily to new services to commercial and industrial customers.
- $566,000 from Delmarva customer growth. We experienced two percent residential customer growth, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operation.

Additional Revenue from GRIP in Florida

In August 2012, the Florida PSC approved a surcharge for GRIP for FPU and Chesapeake's Florida division. This surcharge is designed to recover capital and other program-related costs, inclusive of an appropriate rate of return on investment, associated with accelerating the replacement of qualifying distribution mains and services. During 2013, FPU and Chesapeake's Florida division recorded $724,000 in additional gross margin as a result of the increased GRIP spending.

Increased Customer Consumption—Weather and Other

Higher customer consumption, due to temperatures on the Delmarva Peninsula returning to more normal levels in 2013, generated increased gross margin of approximately $984,000. Higher non-weather related consumption generated additional gross margin of $42,000. This was partially offset by $571,000 in lower gross margin as a result of warmer weather in Florida.

Other Operating Expenses

The increase in other operating expenses was due primarily to (a) $3.1 million in other operating expenses associated with Sandpiper's operations; (b) $1.7 million in higher payroll and benefits costs to support recent growth and expand our capabilities for future growth; (c) $1.3 million of increased incentive bonuses as a result of broader participation in the bonus program, which was extended during 2013 to cover substantially all employees, and the strong financial performance in 2013; (d) $1.4 million in higher depreciation, amortization, asset removal costs and property taxes associated with capital expenditures to support growth and maintain system integrity; (e) a one-time sales tax of $726,000 expensed by Sandpiper related to the ESG acquisition in May 2013; and (f) $342,000 in increased bad debt expense. These increases were partially offset by a $1.5 million recovery of previously expensed costs related to litigation involving our franchise with the City of Marianna, Florida.

UNREGULATED ENERGY

For the Year Ended December 31,	2014	2013	Increase (decrease)	2013	2012	Increase (decrease)
(in thousands)						
Revenue	$184,961	$166,723	$18,238	$166,723	$133,049	$33,674
Cost of sales	137,081	121,348	15,733	121,348	97,137	24,211
Gross margin	47,880	45,375	2,505	45,375	35,912	9,463
Operations & maintenance	30,197	26,657	3,540	26,657	22,804	3,853
Asset impairment charges	432	—	432	—	—	—
Depreciation & amortization	3,994	3,686	308	3,686	3,420	266
Other taxes	1,534	2,679	(1,145)	2,679	1,333	1,346
Other operating expenses	36,157	33,022	3,135	33,022	27,557	5,465
Operating Income	$11,723	$12,353	$(630)	$12,353	$8,355	$3,998

2014 Compared to 2013

Operating income for the Unregulated Energy segment was $11.7 million, a decrease of $630,000, compared to 2013. An increase in gross margin of $2.5 million was more than offset by $432,000 in asset impairment charges for goodwill and intangible assets related to the 2013 acquisition by Austin Cox and an increase in other operating expenses of $2.7 million.

Gross Margin

Items contributing to the year-over-year increase of $2.5 million, or six percent, in gross margin were as follows:

(in thousands)	
Gross margin for the year ended December 31, 2013	$45,375
Factors contributing to the gross margin increase for the year ended December 31, 2014:	
Increased customer consumption—weather and other	1,412
Increased wholesale propane sales	1,391
Decrease in retail propane margins	(356)
Other	58
Gross margin for the year ended December 31, 2014	$47,880

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Increased Customer Consumption—Weather and Other

Higher customer consumption due to colder temperatures during 2014 generated an additional gross margin of $1.7 million. This was partially offset by lower non-weather related consumption, which reduced gross margin by $279,000.

Increased Wholesale Propane Sales

An increase in wholesale propane sales generated additional gross margin of $1.4 million due primarily to the supply agreement entered into in May 2013 with an affiliate of ESG.

Decrease in Retail Propane Margins

- Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $2.3 million. A significant increase in wholesale prices in late 2013 and early 2014 increased our propane inventory cost in 2014 and reverted retail margins to more normal levels. In addition, a rapid decline in wholesale prices in late 2014 resulted in a lower-of-cost-or-market propane inventory valuation adjustment and our decision to discontinue hedge accounting on swap agreements to recognize the expected losses on those agreements in current years' earnings. The lower-of-cost-or-market adjustment and the discontinuation of hedge accounting decreased retail margins per gallon in 2014.
- This decrease was partially offset by $1.9 million in higher retail propane margins in Florida as local market conditions enabled the Florida propane distribution operations to maintain strong margins on sales despite volatility in propane supply costs. The propane retail price per gallon is subject to various market conditions, including competition with other propane suppliers and the availability and price of alternative energy sources. The propane retail price per gallon may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Operating Expenses

The increase in other operating expenses, excluding impairment charges, was due primarily to: (a) $1.9 million in higher payroll and benefits costs due to increased seasonal overtime and additional resources to support growth; (b) $897,000 in additional expenses associated with serving newly acquired customers; and (c) $540,000 in higher costs associated with facilities maintenance. These increases were partially offset by the non-recurrence of a contingency accrual of $990,000 in 2013 related to taxes other than income.

2013 Compared to 2012

Operating income for our Unregulated Energy segment for 2013 was $12.4 million, an increase of $4.0 million, or 48 percent. An increase in gross margin of $9.5 million was partially offset by an increase in other operating expenses of $5.5 million.

Gross Margin

Items contributing to the year-over-year increase of $9.5 million, or 26 percent, in gross margin were as follows:

(in thousands)	
Gross margin for the year ended December 31, 2012	$35,912
Factors contributing to the gross margin increase for the year ended December 31, 2013:	
Increased customer consumption—weather and other	4,233
Increase in propane margins	3,163
Contributions from acquisitions	1,989
Other	1,215
Decreased propane wholesale marketing margins	(1,137)
Gross margin for the year ended December 31, 2013	$45,375

Increased Customer Consumption—Weather and Other

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

•

$3.0 million from increased weather-related consumption. Temperatures on the Delmarva Peninsula returned to more normal levels in 2013, which generated additional gross margin of $3.1 million. This was offset by an $83,000 decrease in gross margin in Florida.

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• $573,000 from non-weather-related volumes. This was attributable to the timing of deliveries to bulk customers.
• $675,000 from higher wholesale sales. An increase in wholesale propane sales generated additional gross margin.

Increase in Propane Margins

Higher retail propane margins during 2013 generated $3.2 million of additional gross margin. Retail margins on the Delmarva Peninsula remained strong throughout 2013 as our propane supply management resulted in a decrease in the average cost of inventory during 2013, which considerably outpaced a slight decline in retail prices during most of 2013. The propane retail prices are 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.

Contributions from Acquisitions

The acquisitions of the operating assets of Glades in February 2013 and Austin Cox in June 2013 generated $1.2 million and $820,000, respectively, of additional gross margin in 2013.

Other

Increased gross margin from other factors is primarily attributable to $192,000 and $746,000 from merchandise sales and miscellaneous fees, respectively.

Decreased propane wholesale marketing margins

Xeron experienced a decrease in gross margin of $1.1 million, as a result of lower margins on executed trades. Lower price volatility in the wholesale propane market and a decrease in trading volume reduced opportunities for Xeron to generate a profit in 2013 until primarily the latter part of the year.

Other Operating Expenses

The increase in other operating expenses was due primarily to: (a) $2.2 million in additional expenses associated with serving newly acquired customers, (b) an accrual of $990,000 due to a contingency for taxes other than income, and (c) $706,000 in increased incentive bonuses as a result of the strong financial performance in 2013.

OTHER

For the Year Ended December 31, (in thousands)	2014	2013	Increase (decrease)	2013	2012	Increase (decrease)
Revenue	$15,911	$19,990	$(4,079)	$19,990	$18,357	$1,633
Cost of sales	7,771	10,544	(2,773)	10,544	8,872	1,672
Gross margin	8,140	9,446	(1,306)	9,446	9,485	(39)
Operations & maintenance	6,797	7,761	(964)	7,761	6,953	808
Depreciation & amortization	407	457	(50)	457	438	19
Other taxes	784	931	(147)	931	814	117
Other operating expenses	7,988	9,149	(1,161)	9,149	8,205	944
Operating Income — Other	152	297	(145)	297	1,280	(983)
Operating Income — Eliminations	(47)	—	(47)	—	1	(1)
Operating Income	$105	$297	$(192)	$297	$1,281	$(984)

2014 Compared to 2013

The “Other” segment reported operating income of $105,000 in 2014, compared to $297,000 in 2013. The decrease in operating income is due to BravePoint's lower operating results prior to the sale on October 1, 2014. The sale of BravePoint produced a pre-tax gain of $6.7 million, which has been reflected as non-operating income.

2013 Compared to 2012
The “Other” segment reported operating income of $297,000 for 2013, compared to $1.3 million in 2012. This decrease was primarily attributable to a decrease in the operating results of BravePoint, which reported a $154,000 operating loss in 2013, compared to operating income of $828,000 in 2012.

Gross margin for BravePoint for 2013 and 2012 remained unchanged at $8.6 million. Other operating expenses increased by $943,000 to $8.7 million in 2013 due primarily to BravePoint's higher payroll and related costs.

GAIN FROM SALE OF BUSINESSES

On October 1, 2014, we completed the sale of BravePoint for approximately $12.0 million. We recorded a pre-tax gain of approximately $6.7 million ($4.0 million after-tax) from this sale in the fourth quarter of 2014. We plan to reinvest the proceeds from this sale in our regulated and unregulated energy businesses. We also recorded a gain of $396,000 from the sale of the fuel line maintenance business in Florida in April 2014. No businesses were sold in 2013 and 2012.

OTHER INCOME

Other income for 2014, 2013 and 2012 was $101,000, $372,000 and $271,000, respectively, which includes non-operating investment income, interest income, late fees charged to customers and gains or losses from the sale of assets.

INTEREST EXPENSE

2014 Compared to 2013
Interest expense for the year ended December 31, 2014 increased by approximately $1.2 million, or 15 percent, compared to the same period in 2013. The increase in interest expense was attributable primarily to the Notes issued in December 2013 and May 2014.

2013 Compared to 2012
Interest expense for the year ended December 31, 2013 decreased by approximately $513,000, or six percent, compared to the same period in 2012. The decrease in interest expense was attributable primarily to decreases of $700,000 in other long-term interest expense due to scheduled repayments and $321,000 in interest on deposits from customers due to a lower interest rate on those deposits. These decreases were partially offset by an increase of $501,000 in short-term interest expense due to higher borrowings in 2013.

INCOME TAXES

2014 Compared to 2013
Income tax expense was $23.9 million in 2014, compared to $22.1 million in 2013. Our effective tax rate was 39.9 percent in 2014, compared to 40.2 percent in 2013.

2013 compared to 2012
Income tax expense was $22.1 million in 2013, compared to $19.3 million in 2012. Our effective tax rate was 40.2 percent in 2013, compared to 40.1 percent in 2012.

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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 for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures during 2014, 2013 and 2012 were $98.1 million, $108.0 million, and $78.2 million, respectively. The significant increase in our capital expenditures in 2014 and 2013, compared to 2012, resulted from the acquisition of ESG and additional capital investment in the Florida GRIP.

We have budgeted $223.4 million for capital expenditures during 2015. The following table shows the 2015 capital expenditure budget by segment and by business line:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$73,379
Natural gas transmission	93,041
Electric distribution	9,646
Total Regulated Energy	176,066
Unregulated Energy:	
Propane distribution	6,219
Other unregulated energy	33,033
Total Unregulated Energy	39,252
Other	
Other corporate and common	8,047
Total Other	8,047
Total 2015 Capital Expenditures	$223,365

The significant increase in our 2015 capital budget, compared to our historic capital expenditures in the past three years, is due to expansions of our natural gas distribution and transmission systems, increased natural gas infrastructure improvement activities, improvement of our facilities and systems and other strategic initiatives and investments expected in 2015. 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 the past three years, our actual capital expenditures were 82 percent to 88 percent of the original budgeted amounts.

In addition to the 2015 capital expenditure budget shown above, we announced in January 2015 that we entered into a merger agreement with Gatherco. At the closing, we expect to pay $57.5 million, to be funded in common stock and cash, and assume $1.7 million of Gatherco's debt. We expect to pay off this debt shortly after closing. This acquisition is expected to close in the second quarter of 2015.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors.

The following presents our capitalization, excluding and including short-term borrowings, as of December 31, 2014 and 2013:

	December 31, 2014			December 31, 2013		
(in thousands)						
Long-term debt, net of current maturities	$158,486	35	%	$117,592	30	%
Stockholders’ equity	300,322	65	%	278,773	70	%
Total capitalization, excluding short-term borrowings	$458,808	100	%	$396,365	100	%

	December 31, 2014			December 31, 2013		
(in thousands)						
Short-term debt	$88,231	16	%	$105,666	21	%
Long-term debt, including current maturities	167,595	30	%	128,945	25	%
Stockholders’ equity	300,322	54	%	278,773	54	%
Total capitalization, including short-term borrowings	$556,148	100	%	$513,384	100	%

In September 2013, we entered into an agreement with the Note Holders to issue $70.0 million of uncollateralized senior notes. We issued $20.0 million of these notes in December 2013, and the remaining $50.0 million in May 2014. Both are included in long-term debt at December 31, 2014. The proceeds from this issuance were used to reduce our short-term borrowings and fund capital expenditures.

As of December 31, 2014, we did not have any restrictions on our cash balances. Both Chesapeake’s senior notes and FPU’s first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2014, $162.9 million of Chesapeake’s cumulative consolidated net income and $66.5 million of FPU’s cumulative net income were free of such restrictions.

Included in the long-term debt balance at December 31, 2014 was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($4.8 million net of current maturities and $6.1 million including current maturities). At the closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.

In conjunction with the Gatherco acquisition, which is expected to close in the second quarter of 2015, we expect to issue common stock valued at $29.9 million and pay cash in the amount of $27.6 million. In order to fund the cash payment of $27.6 million at the closing of this acquisition and the 2015 capital expenditures currently budgeted at $223.4 million, we expect to increase the level of borrowings during 2015 to supplement cash provided by operating activities. We may look at other financing options with longer terms, as needed. We have maintained our equity at 54 percent to 60 percent of the total capitalization, including short-term borrowings, in the past three years. With the increased level of debt expected during 2015, a ratio of equity to total capitalization is expected to temporarily decline until we issue equity. We will determine the timing of any equity issuance based on market conditions and as revenue-generating projects commence service and begin to generate earnings. We target to maintain a ratio of equity to total capitalization of 50 percent to 60 percent.

Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2014 and 2013 were $88.2 million and $105.7 million, respectively, at the weighted average interest rates of 1.15 percent and 1.26 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. In December 2014, we entered into a new $35.0 million credit facility with a new lender and increased one of our existing credit facilities by $10.0 million. As a result of these additions, we now have six unsecured bank credit facilities with three financial institutions with $210.0 million in total available credit. Three of these credit facilities, totaling $120.0 million, are available under committed lines of credit. Two of these credit facilities, totaling $40.0 million, are available under uncommitted lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. In addition to these bank lines of credit, one of the lenders has made available a $50.0 million short-term revolving credit note. We are currently authorized by our Board of Directors to borrow up to $200.0 million of short-term borrowings, as required. Our outstanding short-term borrowings at December 31, 2014 and 2013 included $2.2 million and $3.1 million, respectively of book overdrafts. Book overdrafts are not actual borrowings under the credit facilities; however, these book overdrafts would be funded through the credit facilities if presented and, therefore, were included in the short-term borrowings.

As of December 31, 2014, we issued $4.4 million in letters of credit to various counter-parties under one of the bank lines of credit. Although the amount of the letters of credit is not included in the outstanding short-term borrowings and we do not anticipate they will be drawn upon by the counter-parties, they reduce the available borrowings under the credit facilities.

Our outstanding borrowings under these unsecured short-term credit facilities at December 31, 2014 and 2013 were $86.0 million and $102.6 million, respectively. Short term borrowings were as follows during 2014, 2013 and 2012:

(in thousands)	2014	2013	2012
Average borrowings	$68,928	$67,367	$23,419
Weighted average interest rate	1.28 %	1.34 %	1.79 %
Maximum month-end borrowings	$86,040	$102,554	$56,421

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Net cash provided by (used in):			
Operating activities	$79,284	$72,931	$66,641
Investing activities	(86,586)	(114,781)	(70,598)
Financing activities	8,520	41,845	4,681
Net increase (decrease) in cash and cash equivalents	1,218	(5)	724
Cash and cash equivalents—beginning of period	3,356	3,361	2,637
Cash and cash equivalents—end of period	$4,574	$3,356	$3,361

Cash Flows Provided by Operating Activities

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

We normally generate a large portion of our annual net income and related 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 2014 and 2013, net cash provided by operating activities was $79.3 million and $72.9 million, respectively, resulting in an increase in cash flows of $6.4 million in 2014. Significant operating activities generating the cash flow change were as follows:

- Net income, adjusted for non-cash adjustments and reconciling activities, increased cash flows by $15.1 million.
- Changes in net accounts receivable and payable increased cash flows by $15.1 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale and marketing subsidiary.

- Net cash flows from changes in inventories increased by approximately $8.7 million as a result of lower commodity prices, which decreased the carrying value of our inventory.

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- These increases in operating cash flow were partially offset by a decrease in cash flows from changes in net regulatory assets and liabilities of $13.3 million, due primarily to a change in fuel cost collected through fuel cost recovery mechanisms and additional piping and conversion costs during 2014, which will be recovered through future rates.
- Higher net income tax payments decreased cash flows by $18.2 million.

During 2013 and 2012, net cash provided by operating activities was $72.9 million and $66.6 million, respectively, resulting in an increase in cash flows of $6.3 million in 2013. Significant operating activities generating the cash flow change were as follows:

- Net income, adjusted for non-cash adjustments and reconciling activities, increased cash flows by $5.6 million.
- Lower net regulatory liabilities increased cash flows by $7.3 million, due primarily to an increase in fuel cost collected through the fuel cost recovery mechanisms during 2013 and the absence of the $1.2 million refund by Eastern Shore in January 2012 to customers as a result of its rate case settlement.
- Higher inventory balances in 2013 decreased cash flows by $5.1 million due primarily to higher propane costs.
- Lower customer deposits decreased cash flows by $1.7 million due to refunds to customers during the year.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $86.6 million and $114.8 million for 2014 and 2013, respectively, resulting in an increase in cash flows of $28.2 million. Significant investing activities contributing to the cash flow change were as follows:

- We paid $20.2 million for various acquisitions in 2013. There were no corresponding transactions during 2014.
- We received $10.2 million associated with the disposition of BravePoint in October 2014, compared to $2.3 million received from the sale of equity securities during 2013.

Net cash used in investing activities totaled $114.8 million and $70.6 million for 2013 and 2012, respectively, resulting in a decrease in cash flows of $44.2 million in 2013. Significant investing activities contributing to the cash flow change were as follows:

- Increased cash paid for capital expenditures during 2013, decreased cash flows by $24.3 million.
- Cash paid for acquisitions during 2013, due primarily to the ESG acquisition in May 2013, decreased cash flows by $20.1 million.

Cash Flows Provided by/Used in Financing Activities

Net cash provided by financing activities totaled $8.5 million and $41.8 million for 2014 and 2013, respectively, resulting in a decrease of $33.3 million in 2014. Significant financing activities generating the cash flow change were as follows:

- Net borrowing/repayment under the line of credit agreements decreased cash flows by $62.6 million. The proceeds from the issuance of Series B Notes were used to repay borrowings under line of credit agreements.
- Net proceeds from and repayments of long-term debt increased cash flows by $28.2 million due primarily to the $50.0 million issuance of Series B Notes in May 2014, compared to $20.0 million from the issuance of Series A Notes in December 2013.

Net cash provided by financing activities totaled $41.8 million and $4.7 million for 2013 and 2012, respectively, resulting in an increase of $37.2 million in 2013. Significant financing activities generating the cash flow change were as follows:

- Higher net short-term borrowings to fund capital expenditures and working capital needs increased cash flows by $20.2 million;
- Net cash provided by long-term debt, due primarily to the new issuances during 2013, partially offset by the repayment of FPU’s first mortgage bonds prior to their maturities, increased cash flows by $20.0 million.
- Book overdrafts decreased cash flows by $2.3 million.
- Higher cash dividends paid during 2013 decreased cash flows by $746,000.

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CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2014:

	Payments Due by Period				
Contractual Obligations	Less than 1 year	1 — 3 years	3 — 5 years	More than 5 years	Total
(in thousands)					
Long-term debt (1)	$7,803	$18,496	$18,597	$116,600	$161,496
Operating leases (2)	1,040	1,279	521	2,315	5,155
Capital leases (2) (3)	1,306	2,754	2,070	—	6,130
Purchase obligations (4)					
Transmission capacity	27,616	55,086	47,974	119,856	250,532
Storage — Natural Gas	1,452	2,785	1,880	1,108	7,225
Commodities	31,672	8,620	3,797	—	44,089
Electric supply	15,134	32,179	33,432	—	80,745
Forward purchase contracts — Propane (5)	2,695	—	—	—	2,695
Unfunded benefits (6)	462	832	720	3,704	5,718
Funded benefits (7)	2,091	4	—	3,608	5,703
Total Contractual Obligations	$91,271	$122,035	$108,991	$247,191	$569,488

(1) This represents principal payments on long-term debt. See Item 8, Financial Statements and Supplementary Data, Note 12, Long-Term Debt, for additional discussion of this item. The expected interest payments on long-term debt are $8.2 million, $15.0 million, $12.7 million and $22.1 million, respectively, for the periods indicated above. Expected interest payments for all periods total $58.0 million.

(2) See Item 8, Financial Statements and Supplementary Data, Note 14, Lease Obligations, for further information.

(3) See Item 8, Financial Statements and Supplementary Data, Note 4, Acquisitions, for further information.

(4) See Item 8, Financial Statements and Supplementary Data, Note 20, Other Commitments and Contingencies, for further information.

(5) We have also entered into forward sale contracts. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk for further information.

(6) We have recorded long-term liabilities of $5.7 million at December 31, 2014 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assume a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations.

(7) We have recorded long-term liabilities of $26.0 million at December 31, 2014 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not considered assets of the Company or included in the Company's balance sheets. The Contractual Obligations table above includes $2.0 million, reflecting the expected payments we will make to the trust funds in 2014. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See Item 8, Financial Statements and Supplementary Data, Note 16, Employee Benefit Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling $3.7 million, funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the Balance Sheet. We assume a retirement age of 65 for purposes of distribution from this account.

OFF-BALANCE SHEET ARRANGEMENTS

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2014 was $31.6 million, with the guarantees expiring on various dates through December 30, 2015.

We issued a letter of credit for $1.0 million, which expires on September 12, 2015, related to the electric transmission services for FPU's northwest electric division. We also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on October 31, 2015, 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 to $40,000 to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of December 31, 2014. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

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We provided a letter of credit for $2.3 million to TETLP related to the precedent agreement and firm transportation service agreement between our Delaware and Maryland divisions. Additional information is presented in Item 8, Financial Statements and Supplementary Data, Note 20, Other Commitments and Contingencies in the Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities but excluding a capital lease obligation was $161.5 million at December 31, 2014, as compared to a fair value of $180.7 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing based in part on the fluctuation in interest rates.

COMMODITY PRICE RISK RELATED TO REGULATED ENERGY SEGMENT

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Purchases under these contracts either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis. For all of our regulated businesses that sell natural gas or electricity to end-use customers, we have fuel cost recovery mechanisms authorized by the PSCs that allow us to periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure that we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers.

COMMODITY PRICE RISK RELATED TO UNREGULATED ENERGY SEGMENT

Our propane distribution business is exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply.

We can store up to approximately 6.3 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. Purchases under forward contracts are typically considered “normal purchases and sales” and are accounted for on an accrual basis. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory. The following highlights our hedging activities:

Hedging Activities in 2014

In August and October 2014, Sharp entered into call options to protect against an increase in propane prices associated with 1.3 million gallons we expect to purchase at market-based prices to supply the demands of our propane price cap program customers. The retail price that we can charge to those customers during the upcoming heating season is capped at a pre-determined level. The call options are exercised if the propane prices rise above the strike price of $1.0875 per gallon in December 2014 through February of 2015 and $1.0650 per gallon in January through March 2015. We will receive the difference between the market price and the strike price during those months. We paid $98,000 to purchase the call options, and we accounted for them as cash flow hedges. As of December 31, 2014, the call options had a fair value of $26,000. The change in fair value of the call option was recorded as unrealized loss in other comprehensive income.

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons expected to be purchased for the upcoming heating season. Under these swap agreements, Sharp receives the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 per gallon for each swap agreement, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap prices, Sharp will pay the difference. These swap agreements essentially fix the price of those 630,000 gallons purchased for the upcoming heating season. We had initially accounted for them as cash flow hedges as the swap agreements met all the requirements. At December 31, 2014, we elected to discontinue hedge accounting on the swap agreements and reclassified $735,000 of unrealized loss from other comprehensive loss to propane cost of sales. We are now accounting for them as derivative instruments on a mark-to-market basis with the change in the fair value reflected in current period earnings. As of December 31, 2014, we had a mark-to-market liability of $735,000 related to the swap agreements.

In May 2014, Sharp also entered into put options to protect against declines in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program in the upcoming heating season. The put options are exercised if propane prices fall below the strike prices of $1.0350, $0.9975 and $0.9475 per gallon, for each option agreement in December 2014 through February 2015, respectively. We will receive the difference between the market price and the strike prices during those months. We paid $128,000 to purchase the put options. We accounted for them as fair value hedges, and there is no ineffective portion of these hedges. As of December 31, 2014, the put options had a fair value of $622,000. The change in fair value of the put options effectively reduced our propane inventory balance.

Hedging Activities in 2013

In June 2013, Sharp 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. If exercised, we would have received the difference between the market price and the strike price if propane prices had fallen below the strike prices of $0.830 per gallon in December 2013 through February of 2014 and $0.860 per gallon in January through March 2014. We accounted for those options as fair value hedges, and there was no ineffective portion of those hedges. We paid $120,000 to purchase the put options, which expired without exercise as the market prices exceeded the strike prices.

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

Hedging Activities in 2012

In May 2012, Sharp entered into call options to protect against an increase in propane prices associated with 1.3 million gallons purchased for the propane price cap program for the months of December 2012 through March 2013. The strike prices of these call options ranged from $0.905 per gallon to $0.990 per gallon during this four-month period. We paid $139,000 to purchase the call options, which expired without exercising the options as the market prices were below the strike prices. We accounted for the call options as a fair value hedge. As of December 31, 2012, the call options had a fair value of $28,000. There was no ineffective portion of this fair value hedge in 2012.

Commodity Contracts for Trading Activities

Our propane wholesale marketing operation, Xeron, 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 counterparties, 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, futures and other contracts at December 31, 2014 and 2013 is presented in the following tables:

At December 31, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	4,200,000	$0.5400 - $0.7900	$0.6714
Purchase	4,201,000	$0.4700 - $1.3176	$0.6416

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the first quarter of 2015.

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At December 31, 2013	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,892,000	$0.9900 - $1.4750	$1.2786
Purchase	1,991,000	$0.9411 - $1.4600	$1.2444

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

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

(in thousands)	2014	2013
Mark-to-market energy assets, including put/call options	$1,055	$385
Mark-to-market energy liabilities, including swap agreements	$1,018	$127

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 periodically 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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation
We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 5, 2015 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
March 5, 2015

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands, except shares and per share data)			
Operating Revenues			
Regulated Energy	$300,442	$264,637	$246,208
Unregulated Energy	184,961	166,723	133,049
Other	13,431	12,946	13,245
Total operating revenues	498,834	444,306	392,502
Operating Expenses			
Regulated energy cost of sales	134,560	118,818	111,402
Unregulated energy and other cost of sales	143,556	126,017	101,957
Operations	102,197	91,452	82,387
Maintenance	9,706	7,509	7,423
Asset impairment charges	6,881	—	—
Depreciation and amortization	26,316	23,965	22,510
Other taxes	13,339	13,811	10,188
Total operating expenses	436,555	381,572	335,867
Operating Income	62,279	62,734	56,635
Gains from sale of businesses	7,139	—	—
Other income, net of other expenses	101	372	271
Interest charges	9,482	8,234	8,747
Income Before Income Taxes	60,037	54,872	48,159
Income taxes	23,945	22,085	19,296
Net Income	$36,092	$32,787	$28,863
Weighted Average Common Shares Outstanding:			
Basic	14,551,308	14,430,962	14,379,216
Diluted	14,604,944	14,543,446	14,507,261
Earnings Per Share of Common Stock:			
Basic	$2.48	$2.27	$2.01
Diluted	$2.47	$2.26	$1.99
Cash Dividends Declared Per Share of Common Stock	$1.067	$1.013	$0.960

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Comprehensive Income

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Net Income	$36,092	$32,787	$28,863
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $(24), $(24) and $(26), respectively	(34)	(36)	(37)
Net gain (loss), net of tax of $(1,997), $1,673 and $(331), respectively	(3,076)	2,565	(498)
Cash Flow Hedges, net of tax:			
Unrealized loss on commodity contract cash flow hedges, net of tax of $(22), $0 and $0, respectively	(33)	—	—
Total Other Comprehensive Income (Loss)	(3,143)	2,529	(535)
Comprehensive Income	$32,949	$35,316	$28,328

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Assets	2014	2013
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	$766,855	$691,522
Unregulated energy	84,773	76,267
Other	18,497	21,002
Total property, plant and equipment	870,125	788,791
Less: Accumulated depreciation and amortization	(193,369)	(174,148)
Plus: Construction work in progress	13,006	16,603
Net property, plant and equipment	689,762	631,246
Current Assets		
Cash and cash equivalents	4,574	3,356
Accounts receivable (less allowance for uncollectible accounts of $1,120 and $1,635, respectively)	53,300	75,293
Accrued revenue	13,617	13,910
Propane inventory, at average cost	7,250	10,456
Other inventory, at average cost	3,699	4,880
Regulatory assets	8,967	2,436
Storage gas prepayments	4,258	4,318
Income taxes receivable	18,806	2,609
Deferred income taxes	—	1,696
Prepaid expenses	6,652	6,910
Mark-to-market energy assets	1,055	385
Other current assets	195	160
Total current assets	122,373	126,409
Deferred Charges and Other Assets		
Goodwill	4,952	4,354
Other intangible assets, net	2,404	2,975
Investments, at fair value	3,678	3,098
Regulatory assets	78,136	66,584
Receivables and other deferred charges	3,164	2,856
Total deferred charges and other assets	92,334	79,867
Total Assets	$904,469	$837,522

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Capitalization and Liabilities	2014	2013
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000)	$7,100	$4,691
Additional paid-in capital	156,581	152,341
Retained earnings	142,317	124,274
Accumulated other comprehensive loss	(5,676)	(2,533)
Deferred compensation obligation	1,258	1,124
Treasury stock	(1,258)	(1,124)
Total stockholders' equity	300,322	278,773
Long-term debt, net of current maturities	158,486	117,592
Total capitalization	458,808	396,365
Current Liabilities		
Current portion of long-term debt	9,109	11,353
Short-term borrowing	88,231	105,666
Accounts payable	44,610	53,482
Customer deposits and refunds	25,197	26,140
Accrued interest	1,352	1,235
Dividends payable	3,939	3,710
Deferred income taxes	832	—
Accrued compensation	10,076	8,394
Regulatory liabilities	3,268	4,157
Mark-to-market energy liabilities	1,018	127
Other accrued liabilities	6,603	7,678
Total current liabilities	194,235	221,942
Deferred Credits and Other Liabilities		
Deferred income taxes	160,232	142,597
Regulatory liabilities	43,419	43,912
Environmental liabilities	8,923	9,155
Other pension and benefit costs	35,027	21,000
Deferred investment tax credits and Other liabilities	3,825	2,551
Total deferred credits and other liabilities	251,426	219,215
Other commitments and contingencies (Note 19 and 20)		
Total Capitalization and Liabilities	$904,469	$837,522

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Operating Activities			
Net Income	$36,092	$32,787	$28,863
Adjustments to reconcile net income to net operating cash:			
Goodwill & long-lived asset impairment	6,881	—	—
Depreciation and amortization	26,316	23,965	22,510
Depreciation and accretion included in other costs	6,577	6,123	5,547
Deferred income taxes, net	22,235	14,860	13,881
Realized (gain) loss on sale of assets/investments	(7,293)	(854)	5
Unrealized (gain) loss on investments/commodity contracts	501	(706)	(112)
Employee benefits and compensation	684	1,119	1,199
Share-based compensation	1,958	1,631	1,419
Other, net	3	(28)	(27)
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	20,683	(21,244)	21,549
Propane inventory, storage gas and other inventory	4,177	(4,492)	603
Regulatory assets/liabilities, net	(11,014)	2,328	(4,968)
Prepaid expenses and other current assets	(699)	(1,064)	(713)
Accounts payable and other accrued liabilities	(8,047)	18,824	(19,936)
Income taxes receivable	(15,936)	2,311	2,223
Customer deposits and refunds	(927)	(3,362)	(1,647)
Accrued compensation	37	837	437
Other liabilities	(2,944)	(104)	(4,192)
Net cash provided by operating activities	79,284	72,931	66,641
Investing Activities			
Property, plant and equipment expenditures	(97,164)	(97,120)	(72,776)
Change in intangibles	14	—	—
Proceeds from sale of assets	10,797	199	2,279
Proceeds from sale of investments	—	2,300	630
Acquisitions	—	(20,201)	(124)
Environmental expenditures	(233)	41	(607)
Net cash used by investing activities	(86,586)	(114,781)	(70,598)
Financing Activities			
Common stock dividends	(13,887)	(13,081)	(12,335)
Purchase of stock for Dividend Reinvestment Plan	(165)	(1,342)	(1,273)
Change in cash overdrafts due to outstanding checks	(921)	(1,666)	597
Net borrowing (repayment) under line of credit agreements	(16,513)	46,133	25,894
Proceeds from issuance of long-term debt	49,975	26,766	—
Repayment of long-term debt and capital lease obligation	(9,969)	(14,957)	(8,202)
Other	—	(8)	—
Net cash provided by financing activities	8,520	41,845	4,681

Net Increase (Decrease) in Cash and Cash Equivalents	1,218	(5)	724
Cash and Cash Equivalents — Beginning of Period	3,356	3,361	2,637
Cash and Cash Equivalents — End of Period	$4,574	$3,356	$3,361

Supplemental Cash Flow Disclosures (see Note 6)

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Stockholders' Equity

	Common Stock							
(in thousands, except shares and per share data)	Number of Shares(1)	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2011	14,350,959	$4,656	$149,403	$91,248	$ (4,527)	$ 817	$(817)	$240,780
Net Income	—	—	—	28,863	—	—	—	28,863
Other comprehensive loss	—	—	—	—	(535)	—	—	(535)
Dividend declared ($0.960 per share)	—	—	(7)	(13,872)	—	—	—	(13,879)
Conversion of Debentures	16,463	5	181	—	—	—	—	186
Share-based compensation and tax benefit (2) (3)	28,826	10	1,173	—	—	—	—	1,183
Treasury stock activities(1)	—	—	—	—	—	165	(165)	—
Balance at December 31, 2012	14,396,248	4,671	150,750	106,239	(5,062)	982	(982)	256,598
Net Income	—	—	—	32,787	—	—	—	32,787
Other comprehensive income	—	—	—	—	2,529	—	—	2,529
Dividend declared ($1.013 per share)	—	—	(6)	(14,752)	—	—	—	(14,758)
Conversion of Debentures	26,075	8	287	—	—	—	—	295
Share-based compensation and tax benefit (2) (3)	35,022	12	1,310	—	—	—	—	1,322
Treasury stock activities(1)	—	—	—	—	—	142	(142)	—
Balance at December 31, 2013	14,457,345	4,691	152,341	124,274	(2,533)	1,124	(1,124)	278,773
Net Income	—	—	—	36,092	—	—	—	36,092
Other comprehensive loss	—	—	—	—	(3,143)	—	—	(3,143)
Dividend declared ($1.067 per share)	—	—	—	(15,675)	—	—	—	(15,675)
Retirement savings plan and dividend reinvestment plan	43,367	16	1,844	—	—	—	—	1,860

Conversion of Debentures	47,313	15	520	—	—	—	—	535
Share-based compensation and tax benefit [2] [3]	40,686	13	1,876	—	—	—	—	1,889
Stock split in the form of stock dividend	—	2,365	—	(2,374)	—	—	—	(9)
Treasury stock activities[1]	—	—	—	—	—	134	(134)	—
Balance at December 31, 2014	14,588,711	$7,100	$156,581	$142,317	$ (5,676)	$ 1,258	$(1,258)	$300,322

(1) Includes 53,125, 51,743 and 50,192 shares at December 31, 2014, 2013 and 2012, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

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

(3) The shares issued under the SICP are net of shares withheld for employee taxes. For 2014, 2013 and 2012, we withheld 12,687, 15,617 and 8,505 shares, respectively, for taxes.

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

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1. ORGANIZATION AND BASIS OF PRESENTATION

Chesapeake, incorporated in 1947 in Delaware, is a diversified energy company engaged in regulated energy and unregulated energy businesses. Our regulated energy businesses consist of: (a) regulated natural gas distribution operations in central and southern Delaware, Maryland's eastern shore and Florida; (b) regulated natural gas transmission operations on the Delmarva Peninsula, in Pennsylvania and in Florida; and (c) regulated electric distribution operations serving customers in northeast and northwest Florida. Our unregulated energy businesses primarily include: (a) propane distribution operations in Delaware, the eastern shore of Maryland and Virginia, southeastern Pennsylvania and Florida; (b) our propane wholesale marketing operation, which markets propane to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States; and (c) our natural gas marketing operation providing natural gas supplies directly to commercial and industrial customers in Florida, Delaware and Maryland. On October 1, 2014, we completed the sale of BravePoint, our advanced information services subsidiary. BravePoint provided information-technology-related business services and solutions for both enterprise and e-business applications.

Our consolidated financial statements as of December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012 have been prepared in compliance with the rules and regulations of the SEC and GAAP. Our consolidated financial statements include the accounts of Chesapeake and its wholly-owned subsidiaries. We do not have any ownership interests in investments accounted for using the equity method or any variable interests in a variable interest entity. All intercompany accounts and transactions have been eliminated in consolidation. We have assessed and reported on subsequent events through the date of issuance of these consolidated financial statements.

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

We reclassified certain amounts in the consolidated balance sheet as of December 31, 2013 and consolidated statements of cash flows for the years ended December 31, 2013 and 2012 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates in measuring assets and liabilities and related revenues and expenses. These estimates involve judgments with respect to, among other things, various future economic factors that are difficult to predict and are beyond our control; therefore, actual results could differ from these estimates.

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Property, Plant and Equipment

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Costs include direct labor, materials and third-party construction contractor costs, AFUDC, and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged against income as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. A summary of property, plant and equipment by classification as of December 31, 2014 and 2013 is provided in the following table:

	As of December 31,	
(in thousands)	2014	2013
Property, plant and equipment		
Regulated Energy		
Natural gas distribution – Delmarva	$193,071	$179,724
Natural gas distribution – Florida	234,344	199,289
Natural gas transmission – Delmarva	243,560	226,244
Natural gas transmission – Florida	18,240	15,919
Electric distribution – Florida	77,640	70,346
Unregulated Energy		
Propane distribution—Delmarva	60,877	54,865
Propane distribution – Florida	23,142	20,829
Other unregulated energy	754	573
Other	18,497	21,002
Total property, plant and equipment	870,125	788,791
Less: Accumulated depreciation and amortization	(193,369)	(174,148)
Plus: Construction work in progress	13,006	16,603
Net property, plant and equipment	$689,762	$631,246

Contributions or Advances in Aid of Construction

Customer contributions or advances in aid of construction reduce property, plant and equipment unless the amounts are refundable to customers. Contributions or advances may be refundable to customers after a number of years based on the amount of revenues generated from the customers or the duration of the service provided to the customers. Refundable contributions or advances are recorded initially as liabilities. The amounts that are determined to be non-refundable reduce property, plant and equipment at the time of such determination. During the years ended December 31, 2014 and 2013, there were $813,000 and $785,000, respectively, of non-refunded contributions or advances reducing property, plant and equipment.

Allowed Funds Used During Construction

Some of the additions to our regulated property, plant and equipment include AFUDC, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects. AFUDC is capitalized in rate base for rate making purposes when the completed projects are placed in service. During the years ended December 31, 2014, 2013, and 2012, we recorded $58,000, $131,000, and $111,000, respectively, of AFUDC, all of which were related to short-term debt and reflected as a reduction of interest charges.

Asset Used in Leases

Property, plant and equipment for the Florida natural gas transmission operation includes $1.4 million of assets, consisting primarily of mains, measuring equipment and regulation station equipment used by Peninsula Pipeline to provide natural gas transmission service pursuant to a contract with a third party. This contract is accounted for as an operating lease due to the exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and generates $264,000 in annual revenue for a term of 20 years. Accumulated depreciation for these assets totaled $435,000 and $363,000 at December 31, 2014 and 2013, respectively.

Capital Lease Asset
Property, plant and equipment for our Delmarva natural gas distribution operation includes a capital lease asset of $6.1 million and $7.0 million, net of amortization, at December 31, 2014 and 2013, respectively, related to Sandpiper's capacity, supply and operating agreement. See Note 20, Other Commitments and Contingencies for additional information. At December 31, 2014 and 2013, accumulated amortization for the capital lease asset was $996,000 and $147,000, respectively. For the years ended December 31, 2014 and 2013, we recorded $848,000 and $147,000, respectively in amortization of the capital lease asset which was included in our fuel cost recovery mechanisms.
Jointly-owned pipeline
Property, plant and equipment for the Florida natural gas transmission operation also includes $6.7 million of assets, which consists of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned by Peninsula Pipeline and Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline’s 45-percent ownership of this pipeline. This 16-mile pipeline was placed in service in December 2012. Accumulated depreciation for this pipeline totaled $584,000 and $361,000, at December 31, 2014 and 2013, respectively.
Impairment of long-lived assets
We periodically evaluate whether events or circumstances have occurred which indicate that other long-lived assets may not be fully recoverable. When such events or circumstances are present, we record an impairment loss equal to the excess of the assets' carrying value over its fair value if any.
At December 31, 2014, we recorded a $6.5 million pre-tax, non-cash impairment loss related to uncertainty around the implementation of a customer billing system. We recorded $6.4 million of this impairment loss in the Regulated Energy segment, with the remaining $19,000 included in the Unregulated Energy segment. This impairment represents all of the capitalized costs associated with this project. Prior to December 31, 2014, these costs were included in construction work in progress. We are engaged in negotiations with the system vendor regarding the implementation, and are considering several options to recover these costs, including regulatory proceedings. The outcome cannot be predicted at this time. We will record a gain contingency if and when any recovery from the vendor is realizable or establish a regulatory asset if future recovery through rates is probable, respectively.

Depreciation and Accretion Included in Operations Expenses
We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the regulators. The following table shows the average depreciation rates used during the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Natural gas distribution – Delmarva	2.5%	2.5%	2.5%
Natural gas distribution – Florida	2.9%	3.4%	3.3%
Natural gas transmission – Delmarva	2.7%	2.7%	2.7%
Natural gas transmission – Florida	4.0%	4.8%	4.4%
Electric distribution – Florida	3.8%	3.6%	3.8%

During 2014, the Florida PSC approved new depreciation rates for our Florida natural gas distribution operations (see Note 18, Rates and Other Regulatory Activities, for additional information), which lowered their depreciation rates effective January 1, 2014.

For our unregulated operations, we compute depreciation expense on a straight line basis over the following estimated useful lives of the assets:

Asset Description	Useful Life
Propane distribution mains	10-37 years
Propane bulk plants and tanks	10-40 years
Propane equipment	5-33 years
Meters and meter installations	5-33 years
Measuring and regulating station equipment	5-37 years
Office furniture and equipment	3-10 years
Transportation equipment	4-20 years
Structures and improvements	5-45 years
Other	Various

We report certain depreciation and accretion in operations expense, rather than depreciation and amortization expense, in the accompanying consolidated statements of income in accordance with industry practice and regulatory requirements. Depreciation and accretion included in operations expense consists of the accretion of the costs of removal for future retirements of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense. For the years ended December 31, 2014, 2013 and 2012, we reported \$6.6 million, \$6.1 million and \$5.5 million, respectively, of depreciation and accretion in operations expenses.

Regulated Operations

We account for our regulated operations in accordance with ASC Topic 980, Regulated Operations, which includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions, the economics of which require companies to defer costs or revenues in different periods than may be appropriate for unregulated enterprises. When this situation occurs, a regulated company defers the associated costs as regulatory assets on the balance sheet and records them as expense on the income statement as it collects revenues. Further, regulators can also impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future as regulatory liabilities. If we were required to terminate the application of these regulatory provisions to our regulated operations, all such deferred amounts would be recognized in the statement of income at that time, which could have a material impact on our financial position, results of operations and cash flows.

At December 31, 2014 and 2013, the regulated utility operations had recorded the following regulatory assets and liabilities included in our consolidated balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers’ rates.

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	As of December 31,	
	2014	2013
(in thousands)		
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery (1)	$6,865	$1,651
Under-recovered GRIP revenue (1)	1,491	—
Deferred post retirement benefits (2)	19,762	8,578
Deferred transaction and transition costs (3)	—	471
Deferred conversion and development costs (1)	3,745	1,320
Environmental regulatory assets and expenditures (4)	4,452	5,170
Acquisition adjustment (5)	45,607	47,478
Loss on reacquired debt (6)	1,372	1,486
Other	3,809	2,866
Total Regulatory Assets	$87,103	$69,020
Regulatory Liabilities		
Self insurance (7)	$1,003	$1,000
Over-recovered purchased fuel and conservation cost recovery (1)	2,936	2,869
Over-recovered GRIP revenue (1)	—	518
Storm reserve (7)	2,982	2,875
Accrued asset removal cost (8)	39,583	39,510
Deferred gains (9)	—	783
Other	183	514
Total Regulatory Liabilities	$46,687	$48,069

(1) We are allowed to recover the asset or are required to pay the liability in rates. We do not earn an overall rate of return on these assets.

(2) The Florida PSC allowed FPU to treat as a regulatory asset the portion of the unrecognized costs pursuant to ASC Topic 715, Compensation - Retirement Benefits, related to its regulated operations. See Note 16, Employee Benefit Plans, for additional information.

(3) The Florida PSC approved the inclusion of the FPU merger-related costs in our rate base and the recovery of those costs in rates through October 2014. The balance at December 31, 2013 includes the gross-up of this regulatory asset for income tax because a portion of the merger-related costs is not tax-deductible.

(4) All of our environmental expenditures incurred to date and current estimate of future environmental expenditures have been approved by various PSCs for recovery. See Note 19, Environmental Commitments and Contingencies, for additional information on our environmental contingencies.

(5) We are allowed to include the premiums paid in various natural gas utility acquisitions in Florida in our rate bases and recover them over a specific time period pursuant to the Florida PSC approvals. Included in these amounts are $1.3 million of the premium paid by FPU, $34.2 million of the premium paid by Chesapeake in 2009, including the gross up of the amount for income tax, because it is not tax deductible, and $746,000 of the premium paid by FPU in 2010.

(6) Gains and losses resulting from the reacquisition of long-term debt are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.

(7) We have self-insurance and storm reserves that allow us to collect through rates amounts to be used against general claims, storm restoration costs and other losses as they are incurred.

(8) In accordance with regulatory treatment, our depreciation rates are comprised of two components – historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through depreciation expense with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs meet the requirements of authoritative guidance related to regulated

operations, we have accounted for them as a regulatory liability and have reclassified them from accumulated depreciation to accumulated removal costs in our consolidated balance sheets.

(9) Pursuant to the Florida PSC order, we were required to defer and amortize, until 2014, certain gains identified during the FPU merger integration.

We monitor our regulatory and competitive environments to determine whether the recovery of our regulatory assets continues to be probable. If we were to determine that recovery of these assets is no longer probable, we would write off the assets against earnings. We believe that provisions of ASC Topic 980, Regulated Operations, continue to apply to our regulated operations and that the recovery of our regulatory assets is probable.

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Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC in each state in which they operate. Eastern Shore's revenues are based on rates approved by the FERC. Customers' base rates may not be changed without formal approval by these commissions. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters and natural gas marketing customers, whose billing cycles do not coincide with our accounting periods.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in our consolidated statements of income. For propane bulk delivery customers without meters we record revenue in the period the products are delivered and/or services are rendered.

All of our natural gas and electric distribution operations, except for two utilities that do not sell natural gas to end-use customers as a result of deregulation, have fuel cost recovery mechanisms. These mechanisms provide a method of adjusting the billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

Chesapeake's Florida natural gas distribution division and FPU's Indiantown division provide unbundled delivery service to their customers, whereby the customers are permitted to purchase their gas requirements directly from competitive natural gas marketers.

We charge flexible rates to our natural gas distribution industrial interruptible customers to compete with prices of alternative fuels, which these customers are able to use. Neither we nor our interruptible customers are contractually obligated to deliver or receive natural gas on a firm service basis.

We report revenue taxes, such as gross receipts taxes, franchise taxes, and sales taxes, on a net basis.

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services provided to our customers. These costs include primarily the variable 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, for the period prior to the sale of BravePoint, the direct cost of labor for our advanced information services subsidiary. Depreciation expense is not included in our cost of sales.

Operations and Maintenance Expenses

Operations and maintenance expenses include operations and maintenance salaries and benefits, materials and supplies, usage of vehicles, tools and equipment, payments to contractors, utility plant maintenance, customer service, professional fees and other outside services, insurance expense, minor amounts of depreciation, accretion of cost of removal for future retirements of utility assets, and other administrative expenses.

Cash and Cash Equivalents

Our policy is to invest cash in excess of operating requirements in overnight income-producing accounts. Such amounts are stated at cost, which approximates fair value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts
Accounts receivable consist primarily of amounts due for distribution sales of natural gas, electricity and propane and transportation services to customers. An allowance for doubtful accounts is recorded against amounts due to reduce the receivables balance to the amount we reasonably expect to collect based upon our collections experiences and our assessment of customers’ inability or reluctance to pay. If circumstances change, our estimates of recoverable accounts receivable may also change. Circumstances which could affect such estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off when they are deemed to be uncollectible.
Inventories
We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to market values. At December 31, 2014, we reduced our propane inventory value by $681,000 to reflect the lower-of-cost-or-market adjustment.
Goodwill and Other Intangible Assets
Goodwill is not amortized but is tested for impairment at least annually. In addition, goodwill of a reporting unit is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives. Please refer to Note 10, Goodwill and Other Intangible Assets, for additional discussion of this subject.
The annual goodwill impairment test as of December 31, 2014 resulted in a $237,000 goodwill impairment loss associated with the Austin Cox acquisition. We also recorded a $175,000 impairment loss on an intangible asset related to a non-compete agreement associated with the same acquisition.
Other Deferred Charges
Other deferred charges include discount, premium and issuance costs associated with long-term debt. Debt issuance costs are deferred and then are amortized to interest expense over the original lives of the respective debt issuances.

Pension and Other Postretirement Plans
Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates, including the fair value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. We review annually the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities with the assistance of third-party actuarial firms. The assumed discount rates, expected returns on plan assets and the mortality assumption are the factors that generally have the most significant impact on our pension costs and liabilities. The assumed discount rates, health care cost trend rates and rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.
The discount rates are utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When estimating our discount rates, we consider high quality corporate bond rates, such as Moody’s Aa bond index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected life of each of our plans and their respective payment options.
The expected long-term rates of return on assets are utilized in calculating the expected returns on the plan assets component of our annual pension plan costs. We estimate the expected returns on plan assets of each of our plans by evaluating expected bond returns, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rates of return on assets.
We estimate the health care cost trend rates used in determining our postretirement net expense based upon actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual reviews of participant census information as of the measurement

date.
The mortality assumption used for our pension and postretirement plans is based on the actuarial table that is most reflective of the expected mortality of the plan participants and reviewed periodically.
Actual changes in the fair value of plan assets and the differences between the actual and expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $18,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $22,000. A 0.25 percent change in

the rate of return could change our annual pension cost by approximately $134,000 and would not have an impact on the postretirement and supplemental executive retirement plans because these plans are not funded.

Income Taxes, Investment Tax Credit Adjustments and Tax-related contingency

Deferred tax assets and liabilities are recorded for the income tax effect of temporary differences between the financial statement basis and tax basis of assets and liabilities and are measured using the enacted income tax rates in effect in the years in which the differences are expected to reverse. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such income tax benefits will be realized. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

We account for uncertainty in income taxes in the financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and estimable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss assuming the proper inquiries are made by tax authorities.

Financial Instruments

Xeron engages in trading activities using forward and futures contracts, which have been accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, our trading contracts are recorded at fair value as mark-to-market energy assets and liabilities. The changes in fair value of the contracts are recognized as gains or losses in revenues on the consolidated statements of income in the period of change.

Our natural gas, electric and propane distribution operations and natural gas marketing operations enter 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 enter into derivative transactions, such as swaps, put options and call options in order to mitigate the impact of wholesale price fluctuations on its inventory valuation and future purchase commitments. These transactions may be designated as fair value hedges or cash flow hedges, if they meet all of the accounting requirements pursuant to ASC Topic 815, Derivatives and Hedging and we elect to designate the instruments as hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap or put option, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument effectively reducing or increasing the value of propane inventory. If designated as a cash flow hedge, the value of the hedging instrument, such as a swap or call option, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument being recorded in comprehensive income. The ineffective portion of the gain or loss of a hedge is recorded in earnings. If the instrument is not designated as a fair value or cash flow hedge or does not meet the accounting requirements of a hedge, it is recorded at fair value with the gain or loss being recorded in earnings.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. ASU 2014-09 is effective for reporting periods (interim and annual) beginning after December 15, 2016. We are currently assessing the impact this standard will have on our financial position and results of operations.

Recently Adopted Accounting Standards

Presentation of Financial Statements (ASC 205) and Property Plant and Equipment (ASC 360) - In April 2014, the FASB issued ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The new standard limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity's operations and financial results, and requires additional disclosures related to discontinued operations. Upon adoption of the new standard, fewer disposals are expected to be presented as discontinued operations. We early adopted the provisions of this standard in the third quarter of 2014 and applied them to the sale of BravePoint (see Note 4,

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Acquisitions and Disposition, for additional details on the sale). As a result, BravePoint is not presented as a discontinued operation in the accompanying consolidated statements of income.
Income Taxes (ASC 740) - In July 2013, the FASB issued ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which requires the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of an uncertain tax position. ASU 2013-11 became effective for us on January 1, 2014. The adoption of ASU 2013-11 had no material impact on our financial position and results of operations.

3. EARNINGS PER SHARE

Basic earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period adjusted for the exercise and/or conversion of all potentially dilutive securities, such as convertible debt and share-based compensation. The calculations of both basic and diluted earnings per share are presented in the following table.

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands, except shares and per share data)			
Calculation of Basic Earnings Per Share:			
Net Income	$36,092	$32,787	$28,863
Weighted average shares outstanding	14,551,308	14,430,962	14,379,216
Basic Earnings Per Share	$2.48	$2.27	$2.01
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	$36,092	$32,787	$28,863
Effect of 8.25% Convertible debentures	—	43	53
Adjusted numerator — Diluted	$36,092	$32,830	$28,916
Reconciliation of Denominator:			
Weighted shares outstanding — Basic	14,551,308	14,430,962	14,379,216
Effect of dilutive securities:			
Share-based Compensation	53,636	37,866	35,249
8.25% Convertible debentures (1)	—	74,618	92,796
Adjusted denominator — Diluted	14,604,944	14,543,446	14,507,261
Diluted Earnings Per Share	$2.47	$2.26	$1.99

(1) As of March 1, 2014, we no longer have any outstanding convertible debentures. See Note 12, Long-term debt for additional information.

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

4. ACQUISITIONS AND DISPOSITION

Eastern Shore Gas Company

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

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

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

The revenue and net income from this acquisition for the year ended December 31, 2014, included in our consolidated statement of income, was $24.3 million and $2.5 million, respectively. The revenue and net income from this acquisition for the year ended December 31, 2013, included in our consolidated statement of income, was $9.8 million and $309,000, respectively.

Other Acquisitions

On December 2, 2013, we acquired certain operating assets of the City of Fort Meade, Florida, for approximately $792,000. The purchased assets are used to provide natural gas distribution service in the City of Fort Meade, Florida. In connection with this acquisition we recorded $92,000 in property, plant and equipment, $14,000 in inventory, $14,000 in regulatory asset, $714,000 in goodwill and $42,000 in other current liabilities. These amounts reflect adjustments to the purchase price and the allocation of the purchase price during the fourth quarter of 2014 based on our final valuation, which decreased the value of property, plant and equipment by $578,000 and increased goodwill by $564,000. All of the goodwill is expected to be deductible for income tax purposes. The revenue and net income from this acquisition that were included in our consolidated statements of income for the years ended December 31, 2014 and 2013 were not material.

On June 7, 2013, we acquired certain operating assets through 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, $30,000 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 $237,000 in goodwill. The revenue and net income from this acquisition included in our consolidated statements of income for the years ended December 31, 2014 and 2013 were not material. As discussed in Note 2, Summary of Significant Accounting Policies, at December 31, 2014, we recorded an impairment charge of $412,000 related to the goodwill and non-compete intangible asset. The impairment charge represented all of the remaining goodwill and intangible asset from this acquisition.

On February 5, 2013, we purchased the propane operating assets of Glades for approximately $2.9 million. The purchased assets are used to provide propane distribution service to approximately 3,000 residential and commercial customers in Okeechobee, Glades and Hendry Counties, Florida. In connection with this acquisition, we recorded $1.6 million in property, plant and equipment, $231,000 in propane and other inventory, $300,000 in an intangible asset related to Glades’ customer list, to be amortized over 12 years beginning in February 2013 and $724,000 in goodwill. These amounts reflect an adjustment to the allocation of the purchase price during the first quarter of 2014 based on our final valuation, which decreased the value of propane inventory by $271,000 and increased goodwill by the same amount. All of the goodwill is expected to be deductible for income tax purposes. The revenue and net income from this acquisition, included in our consolidated statements of income for the years ended December 31, 2014 and 2013, were not material.

Gatherco Acquisition - Subsequent Event

On January 30, 2015, we entered into a merger agreement to acquire Gatherco. Upon consummation of the transaction, Gatherco will merge into Aspire Energy, a newly formed, wholly-owned subsidiary of Chesapeake. At closing, we expect to issue 593,005 shares of our common stock, valued at $29.9 million, pay $27.6 million in cash and assume Gatherco’s debt, estimated to be $1.7 million. We expect to pay off this debt shortly after closing. Gatherco is a natural gas infrastructure company providing natural gas midstream services. Gatherco’s assets include 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Gatherco provides natural gas gathering services and natural gas liquid processing services to over 300 producers, and supplies natural gas to over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity which Gatherco manages under an operating agreement. The transaction is subject to approval by Gatherco's shareholders and is expected to close in the second quarter of 2015.

Disposition of BravePoint

On October 1, 2014, we completed the sale of BravePoint, our advanced information services subsidiary for approximately $12.0 million in cash. We plan to reinvest the proceeds from this sale in our regulated and unregulated energy businesses. We recorded a pre-tax gain of $6.7 million (approximately $4.0 million after-tax) from this sale, which includes the effect of certain costs and expenses associated with the sale. Our consolidated statements of income for the years ended December 31, 2014, 2013 and 2012 included $15.1 million, $19.1 million and $17.5 million of revenue, respectively, and $232,000 of net loss, $155,000 of net loss and $454,000 of net income, respectively, from BravePoint's operations.

5. SEGMENT INFORMATION

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

- Regulated Energy. The Regulated Energy segment includes natural gas distribution, natural gas transmission operations and electric distribution operations. All operations in this segment are regulated, as to their rates and services, by the PSCs having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.
- Unregulated Energy. The Unregulated Energy segment includes propane distribution and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.
- Other. Prior to September 30, 2014 our “Other” segment consisted primarily of our advanced information services subsidiary. Also included in this segment are our unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations. On October 1, 2014, we sold BravePoint (see Note 4, Acquisitions and Disposition, for further details).

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The following table presents information about our reportable segments.

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	$299,345	$263,573	$245,042
Unregulated Energy	184,557	161,760	130,020
Other	14,932	18,973	17,440
Total operating revenues, unaffiliated customers	$498,834	$444,306	$392,502
Intersegment Revenues (1)			
Regulated Energy	$1,097	$1,064	$1,166
Unregulated Energy	404	4,963	3,029
Other	979	1,017	917
Total intersegment revenues	$2,480	$7,044	$5,112
Operating Income			
Regulated Energy	$50,451	$50,084	$46,999
Unregulated Energy	11,723	12,353	8,355
Other	105	297	1,281
Operating Income	62,279	62,734	56,635
Gain from sale of businesses	7,139	—	—
Other income	101	372	271
Interest charges	9,482	8,234	8,747
Income Before Income taxes	60,037	54,872	48,159
Income taxes	23,945	22,085	19,296
Net Income	$36,092	$32,787	$28,863
Depreciation and Amortization			
Regulated Energy	$21,915	$19,822	$18,653
Unregulated Energy	3,994	3,686	3,420
Other and eliminations	407	457	437
Total depreciation and amortization	$26,316	$23,965	$22,510
Capital Expenditures			
Regulated Energy	$84,959	$95,944	$69,056
Unregulated Energy	9,648	4,829	3,969
Other	3,450	7,266	5,185
Total capital expenditures	$98,057	$108,039	$78,210

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

	As of December 31,	
	2014	2013
Identifiable Assets		
Regulated Energy	$796,021	$708,950
Unregulated Energy	84,732	100,585
Other	23,716	27,987
Total identifiable assets	$904,469	$837,522

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

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6. SUPPLEMENTAL CASH FLOW DISCLOSURES

Cash paid for interest and income taxes during the years ended December 31, 2014, 2013 and 2012 were as follows:

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Cash paid for interest	$8,870	$7,837	$8,086
Cash paid for income taxes	$17,833	$10,243	$3,809

Non-cash investing and financing activities during the years ended December 31, 2014, 2013, and 2012 were as follows:

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Capital property and equipment acquired on account, but not paid as of December 31	$459	$341	$7,065
Retirement Savings Plan	$602	$—	$—
Conversion of Debentures	$535	$295	$186
Performance Incentive Plan	$958	$355	$427
Director Stock Compensation Plan	$575	$495	$443
Capital Lease Obligation	$6,130	$7,126	$—

7. DERIVATIVE INSTRUMENTS

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory or cash flow hedges of its future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2014, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2014

In August and October 2014, Sharp entered into call options to protect against an increase in propane prices associated with 1.3 million gallons we expect to purchase at market-based prices to supply the demands of our propane price cap program customers. The retail price that we can charge to those customers during the upcoming heating season is capped at a pre-determined level. The call options are exercised if the propane prices rise above the strike price of $1.0875 per gallon in December 2014 through February of 2015 and $1.0650 per gallon in January through March 2015. We will receive the difference between the market price and the strike price during those months. We paid $98,000 to purchase the call options, and we accounted for them as cash flow hedges. As of December 31, 2014, the call options had a fair value of $26,000. The change in fair value of the call options was recorded as unrealized loss in other comprehensive income.

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons expected to be purchased for the upcoming heating season. Under these swap agreements, Sharp receives the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 per gallon for each swap agreement, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap prices, Sharp will pay the difference. These swap agreements essentially fix the price of those 630,000 gallons purchased for the upcoming heating season. We had initially accounted for them as cash flow hedges as the swap agreements met all the requirements. At December 31, 2014, we elected to discontinue hedge accounting on the swap agreements and reclassified $735,000 of unrealized loss from other comprehensive loss to propane cost of sales. We are now accounting for them as derivative instruments on a mark-to-market basis with the change in the fair value reflected in current period earnings. As of December 31, 2014, we have a mark-to-market liability of $735,000 related to the swap agreements.

In May 2014, Sharp also entered into put options to protect against declines in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program in the upcoming heating season. The put options are exercised if propane prices fall below the strike prices of $1.0350, $0.9975 and $0.9475 per gallon, for each option agreement in December 2014 through February 2015, respectively. We will receive the difference between the market price and the strike prices during those months. We paid $128,000 to purchase the put options. We accounted for them as fair value hedges, and there is no ineffective portion of these hedges. As of December 31, 2014, the put options had a fair value of $622,000. The change in fair value of the put options effectively reduced our propane inventory balance.

Hedging Activities in 2013

In June 2013, Sharp 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. If exercised, we would have received the difference between the market price and the strike price if propane prices had fallen below the strike prices of $0.830 per gallon in December 2013 through February of 2014 and $0.860 per gallon in January through March 2014. We accounted for those options as fair value hedges, and there was no ineffective portion of those hedges. We paid $120,000 to purchase the put options, which expired without exercise as the market prices exceeded the strike prices.

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

Hedging Activities in 2012

In May 2012, Sharp entered into call options to protect against an increase in propane prices associated with 1.3 million gallons purchased for the propane price cap program for the months of December 2012 through March 2013. The strike prices of these call options ranged from $0.905 per gallon to $0.990 per gallon during this four-month period. We paid $139,000 to purchase the call options, which expired without exercising the options as the market prices were below the strike prices. We accounted for the call options as a fair value hedge. At December 31, 2012, the call options had a fair value of $28,000. There was no ineffective portion of this fair value hedge in 2012.

Commodity Contracts for Trading Activities

Xeron engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, 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 consolidated statements of income in the period of change. As of December 31, 2014 and December 31, 2013, we had the following outstanding trading contracts, which we accounted for as derivatives:

At December 31, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	4,200,000	$0.5400 - $0.7900	$0.6714
Purchase	4,201,000	$0.4700 - $1.3176	$0.6416

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the first quarter of 2015.

At December 31, 2013	Quantity in	Estimated Market

	Gallons	Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	1,892,000	$0.9900 - $1.4750	$1.2786
Purchase	1,991,000	$0.9411 - $1.4600	$1.2444

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 consolidated balance sheets. At December 31, 2014, Xeron had a right to offset $1.6 million and $1.2 million of accounts receivable and accounts payable, respectively, with these two counterparties. At December 31, 2013, Xeron had a right to offset $2.8 million and $3.2 million of accounts receivable and accounts payable, respectively, with these two counterparties.

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The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.
Fair values of the derivative contracts recorded in the consolidated balance sheets as of December 31, 2014 and 2013, are as follows:

	Asset Derivatives		
(in thousands)	Balance Sheet Location	Fair Value As Of December 31, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$407	$196
Call option	Mark-to-market energy assets	—	169
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	622	20
Derivatives designated as cash flow hedges			
Call options	Mark-to-market energy assets	26	—
Total asset derivatives		$1,055	$385

	Liability Derivatives		
(in thousands)	Balance Sheet Location	Fair Value As Of December 31, 2014	December 31, 2013
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$283	$127
Propane swap agreements	Mark-to-market energy liabilities	735	—
Total liability derivatives		$1,018	$127

The effects of gains and losses from derivative instruments are as follows:

	Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Year Ended December 31,		
(in thousands)	(Loss) on Derivatives	2014	2013	2012
Derivatives not designated as hedging instruments:				
Realized gain on forward contracts and options [1]	Revenue	$1,423	$1,127	$2,695
Unrealized gain (loss) on forward contracts [1]	Revenue	57	217	(339)
Call Options	Cost of Sales	—	97	—
Propane swap agreements	Cost of Sales	(735)	—	—
Derivatives designated as fair value hedges:				
Put/Call Option	Cost of Sales	235	(28)	27
Put/Call Option [2]	Propane Inventory	517	(100)	(40)
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of Sales	(341)	—	—

Call Options	Cost of Sales	(17)	—	—
Call Options	Other Comprehensive Income (Loss)	(55)	—	—
Total		$1,084	$1,313	$2,343

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

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

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

Financial Assets and Liabilities Measured at Fair Value

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

		Fair Value Measurements Using:		
(in thousands)	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments—guaranteed income fund	$287	$—	$ —	$287
Investments—other	$3,391	$3,391	$ —	$—
Mark-to-market energy assets, incl. put/call options	$1,055	$—	$ 1,055	$—
Liabilities:				
Mark-to-market energy liabilities, incl. swap agreements	$1,018	$—	$ 1,018	$—

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

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

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The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2014 and 2013:

	For the Year Ended December 31,	
	2014	2013
(in thousands)		
Beginning Balance	$458	$—
Transfers in due to change in trustee	—	425
Purchases and adjustments	76	41
Transfers	(253)	(16)
Investment income	6	8
Ending Balance	$287	$458

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

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

Level 1 Fair Value Measurements:

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

Level 2 Fair Value Measurements:

Mark-to-market energy assets and liabilities — These forward contracts are valued using market transactions in either the listed or OTC markets.

Propane put/call options and swap agreements – The fair value of the propane put/call options and swap agreements are valued 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 December 31, 2014, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At December 31, 2014, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $161.5 million, compared to a fair value of $180.7 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, adjusted for duration, optionality and risk profile. At December 31, 2013, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $122.0 million, compared to the estimated fair value of $136.8 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

Note 16, Employee Benefit Plans, provides the fair value measurement information for our pension plan assets.

9. INVESTMENTS

The investment balances at December 31, 2014 and 2013, consist of the Rabbi Trust(s) associated with deferred compensation plan(s). We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2014, 2013 and 2012, we recorded net unrealized gains of $237,000, $489,000, and $451,000, respectively, in other income in the consolidated statements of income related to these investments. We have also recorded an associated liability, which is included in other pension and benefit costs in the consolidated balance sheets and is adjusted each month for the gains and losses incurred by the Rabbi Trusts. During 2013, we sold our investments in equity securities and recorded $702,000 of realized gain, $438,000 of which was previously recorded as unrealized gain ($135,000 in 2012 and $304,000 prior to 2012).

10. GOODWILL AND OTHER INTANGIBLE ASSETS

The carrying value of goodwill as of December 31, 2014 and 2013 was as follows:

	As of December 31,	
(in thousands)	2014	2013
Regulated Energy segment	$3,354	$2,790
Unregulated Energy segment	1,598	1,564
Total	$4,952	$4,354

As of December 31, 2014, goodwill in the Regulated Energy segment is comprised of approximately $2.5 million from the FPU merger in October 2009, $170,000 from the purchase of operating assets from IGC in August 2010 and $714,000 from the purchase of Fort Meade in December 2013. During 2013, approximately $576,000 of the $746,000 goodwill that was originally recorded as a result of the IGC acquisition was reclassified to regulatory asset pursuant to the regulatory order which allowed recovery of the amount in rates. As of December 31, 2014, goodwill in the Unregulated Energy segment is comprised of $724,000 from the purchase of the operating assets of Glades in February 2013, $200,000 from the purchase of the operating assets from Crescent in December 2011 and $674,000 related to the premium paid by Sharp from its acquisitions in the late 1980s and 1990s. As discussed in Note 2, Summary of Significant Accounting Policies, at December 31, 2014, we recorded an impairment loss of $237,000 associated with the goodwill resulting from the Austin Cox acquisition in 2013. The impairment loss represents all of the goodwill recorded from the Austin Cox acquisition. The annual impairment testing for 2013 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2014 and 2013 are as follows:

	As of December 31,			
	2014		2013	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer lists	$3,993	$1,719	$3,993	$1,389
Non-Compete agreements	103	72	353	87
Other	270	171	270	165
Total	$4,366	$1,962	$4,616	$1,641

The customer lists acquired in the purchases of the operating assets of Glades in February 2013, Virginia LP in February 2010 and the FPU merger in October 2009 are being amortized over seven to 12 years. The non-compete agreements acquired in the purchase of the operating assets of Virginia LP in February 2010 are being amortized over a seven-year period. The other intangible assets consist of acquisition costs from our propane distribution acquisitions in the late 1980s and 1990s and are being amortized over 40 years. As discussed in Note 2, Summary of Significant Accounting Policies, at December 31, 2014, we recorded an impairment loss of $175,000 for an intangible asset associated with the non-compete agreements acquired in the Austin Cox acquisition in 2013. The impairment loss represents all of the remaining intangible asset from the Austin Cox acquisition.

For the years ended December 31, 2014, 2013 and 2012, amortization expense of intangible assets was $396,000, $373,000 and $329,000, respectively. Amortization expense of intangible assets is expected to be: $350,000 for 2015, $325,000 for 2016, $323,000 for 2017, $323,000 for 2018, and $323,000 for 2019.

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11. INCOME TAXES

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. Our returns for tax years after 2011 are subject to examination.

The IRS performed its examination of Chesapeake's consolidated federal income tax return for 2009 and FPU's consolidated federal income tax return for 2008 and the period from January 1, 2009 to October 28, 2009 (the pre-merger period in 2009, during which FPU was required to file a separate federal income tax return). Both of the IRS examinations were completed in 2012 without any material findings.

The State of Florida performed its examination of Chesapeake’s state income tax returns for 2008, 2009 and 2010 and completed its examination in 2012 without any material findings.

The State of Texas performed its examination of Chesapeake’s amended state tax return for 2007. We amended the 2007 Texas state tax return due to a change in the methodology used to calculate the gross receipts used to determine the Texas apportionment. This new methodology was used in Chesapeake’s Texas tax returns for all years after 2006. In 2012, we recorded a total liability of $300,000 associated with the unrecognized tax benefit related to this change in methodology given the unknown outcome of this examination. In 2014, we reduced this liability to $100,000 based on the result of the examination by the State of Texas. We recorded this liability associated with the unrecognized tax benefit as an income tax payable, which reduced the income tax receivable in the accompanying balance sheets at December 31, 2014 and 2013.

We did not have net operating losses for federal income tax purposes as of December 31, 2014 and 2013. We had state net operating losses of $29.1 million in various states as of December 31, 2014, almost all of which will expire in 2030. We have recorded a deferred tax asset of $1.2 million and $1.4 million related to net operating loss carry-forwards at December 31, 2014 and 2013, respectively. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

The following tables provide: (a) the components of income tax expense in 2014, 2013, and 2012; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2014, 2013, and 2012; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2014 and 2013.

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Current Income Tax Expense			
Federal	$434	$4,882	$3,483
State	1,311	2,382	1,990
Investment tax credit adjustments, net	(35)	(39)	(58)
Total current income tax expense	1,710	7,225	5,415
Deferred Income Tax Expense [1]			
Property, plant and equipment	20,382	16,758	13,688
Deferred gas costs	1,614	(209)	515
Pensions and other employee benefits	537	(335)	553
FPU merger related premium cost and deferred gain	(802)	(686)	(509)
Net operating loss carryforwards	(112)	62	740
Other	616	(730)	(1,106)
Total deferred income tax expense	22,235	14,860	13,881
Total Income Tax Expense	$23,945	$22,085	$19,296

[1]

Includes $2.6 million, $2.1 million, and $1.9 million of deferred state income taxes for the years 2014, 2013 and 2012, respectively.

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	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Reconciliation of Effective Income Tax Rates			
Continuing Operations			
Federal income tax expense [(1)]	$21,121	$19,205	$16,745
State income taxes, net of federal benefit	2,946	3,105	2,571
ESOP dividend deduction	(267)	(256)	(235)
Other	145	31	215
Total Income Tax Expense	$23,945	$22,085	$19,296
Effective Income Tax Rate	39.88 %	40.25 %	40.07 %

(1) Federal income taxes were recorded at 35% for each year represented.

	As of December 31,	
	2014	2013
(in thousands)		
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	$152,877	$134,414
Acquisition adjustment	16,140	16,790
Loss on reacquired debt	529	573
Deferred gas costs	2,222	607
Other	4,507	2,850
Total deferred income tax liabilities	176,275	155,234
Deferred income tax assets:		
Pension and other employee benefits	6,532	5,390
Environmental costs	2,313	2,083
Net operating loss carryforwards	1,186	1,444
Self insurance	275	403
Storm reserve liability	1,150	1,109
Other	3,755	3,904
Total deferred income tax assets	15,211	14,333
Deferred Income Taxes Per Consolidated Balance Sheets	$161,064	$140,901

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12. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

	As of December 31,	
	2014	2013
(in thousands)		
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	7,969	7,967
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	—	2,000
6.64% note, due October 31, 2017	8,182	10,909
5.50% note, due October 12, 2020	12,000	14,000
5.93% note, due October 31, 2023	27,000	30,000
5.68% note, due June 30, 2026	29,000	29,000
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	—
Convertible debentures:		
8.25% due March 1, 2014	—	646
Promissory notes	314	445
Capital lease obligation	6,130	6,978
Total long-term debt	167,595	128,945
Less: current maturities	(9,109)	(11,353)
Total long-term debt, net of current maturities	$158,486	$117,592

Annual maturities and principal repayments of consolidated long-term debt, excluding the capital lease obligation, are as follows: $9,109 for 2015; $9,151 for 2016; $12,099 for 2017; $9,421 for 2018; $11,245 for 2019 and $116,600 thereafter. See Note 14, Lease obligations for future payments related to the capital lease obligation.

Secured First Mortgage Bonds

FPU's secured first mortgage bonds are guaranteed by Chesapeake and are secured by a lien covering all of FPU's property. FPU's first mortgage bonds contain a restriction that limits the payment of dividends by FPU. It provides that FPU cannot make dividends or other restricted payments in excess of the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2014, FPU's cumulative net income base was $104.1 million, offset by restricted payments of $37.6 million, leaving $66.5 million of cumulative net income for FPU free of restrictions pursuant to this covenant.

The dividend restrictions by FPU's first mortgage bonds resulted in approximately $49.4 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2014. This represents approximately 16 percent of our consolidated net assets. Other than the dividend restrictions by FPU's first mortgage bonds, there are no legal, contractual or regulatory restrictions on the net assets of our subsidiaries for the purposes of determining the disclosure of parent-only financial statements.

Uncollateralized Senior Notes

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

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.

All of our uncollateralized Senior Notes require periodic principal and interest payments as specified in each note. They also contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40 percent of total

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capitalization, and the fixed charge coverage ratio must be at least 1.2 times. The most recent Senior Notes issued in December 2013 also contain a restriction that we must maintain an aggregate net book value in our regulated business assets of at least 50 percent of our consolidated total assets. Failure to comply with those covenants could result in accelerated due dates and/or termination of the uncollateralized senior note agreements. As of December 31, 2014, we are in compliance with all of our debt covenants.

Most of Chesapeake's uncollateralized Senior Notes contain a "Restricted Payments" covenant as defined in the Note agreements. The most restrictive covenants of this type are included within the 5.68 percent and 6.43 percent Senior Notes, due June 30, 2026 and May 2, 2028, respectively. The covenant provides that we cannot pay or declare any dividends or make any other Restricted Payments in excess of the sum of $10.0 million, plus our consolidated net income accrued on and after January 1, 2003. As of December 31, 2014, the cumulative consolidated net income base was $243.8 million, offset by Restricted Payments of $80.9 million, leaving $162.9 million of cumulative net income free of restrictions.

Convertible Debentures

During January and February of 2014, $537,000 of Convertible Debentures were converted to stock at a conversion price of $17.01 per share and $109,000 were redeemed for cash, leaving no outstanding Convertible Debentures as of March 1, 2014. During 2013, Convertible Debentures totaling $296,000 were converted to stock. No Convertible Debentures were redeemed for cash in 2013.

13. SHORT-TERM BORROWINGS

At December 31, 2014 and 2013, we had $88.2 million and $105.7 million, respectively, of short-term borrowings outstanding. In December 2014, we entered into a new $35.0 million credit facility with a new lender and increased one of our existing credit facilities by $10.0 million. As a result of these additions, we now have six unsecured bank credit facilities with three financial institutions with $210.0 million in total available credit. The annual weighted average interest rates on our short-term borrowings were 1.15 percent and 1.26 percent for 2014 and 2013, respectively. We incurred commitment fees of $87,000 and $56,000 in 2014 and 2013, respectively.

				Outstanding borrowings at		
(in thousands)	Total Facility	Interest Rate	Expiration Date	December 31, 2014	December 31, 2013	Available at December 31, 2014
Bank Credit Facility						
Committed revolving credit facility A	$55,000	LIBOR plus 1.25 percent	June 26, 2015	$20,000	$35,000	$35,000
Committed revolving credit facility B	30,000	LIBOR plus 1.25 percent (1)	October 31, 2015	16,040	17,554	13,960
Committed revolving credit facility C	35,000	LIBOR plus 0.85 percent	December 22, 2015	—	—	35,000
Short-term revolving credit Note D	50,000	LIBOR plus 0.80 percent (3)	October 31, 2015	50,000	40,000	—
Uncommitted revolving credit facility E	20,000	Rate offered by the bank	June 26, 2015	—	—	20,000
Uncommitted revolving credit facility F (2)	20,000	Rate offered by the bank	October 31, 2015	—	10,000	20,000
Total short term credit facilities	$210,000			$86,040	$102,554	$123,960
Book overdrafts(4)				2,191	3,112	
Total short-term borrowing				$88,231	$105,666	

[1] This facility bears interest at LIBOR for the applicable period plus 1.25 percent, if requested three days prior to the advance date. If requested and
advanced on the same day, this facility bears interest at a base rate plus 1.25 percent.
[2] We have issued $4.4 million in letters of credit under this credit facility as of December 31, 2014. There have been no draws on these letters of credit,
and we do not anticipate that they will be drawn upon by the counter-parties. We expect that the letters of credit will be renewed to the
extent necessary in the future.
[3] At our discretion, the borrowings under this facility can bear interest at the lender's base rate plus 0.80 percent.
[4] If presented, these book overdrafts would be funded through the bank revolving credit facilities.

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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. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $200.0 million of short-term debt, as required, from these short-term lines of credit.
The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal year:

- a funded indebtedness ratio of no greater than 65 percent; and
- a fixed charge coverage ratio of at least 1.20 to 1.0.

We are in compliance with all of our debt covenants.

14. LEASE OBLIGATIONS

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases for 2014, 2013 and 2012 was $1.8 million, $1.6 million and $1.4 million, respectively. Future minimum payments under our current lease agreements for the years 2015 through 2019 are $1.1 million, $942,000, $338,000, $293,000, and $228,000, respectively; and approximately $2.3 million thereafter, with an aggregate total of approximately $5.2 million.
For the years ended December 31, 2014 and 2013, we paid $1.1 million for a capital lease arrangement related to Sandpiper's capacity, supply and operating agreement. Future minimum payments under this lease arrangement are $1.5 million for 2015 through 2018 and $625,000 in 2019, with an aggregate total of $6.6 million.

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15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Defined benefit pension and postretirement plan items and unrealized gains (losses) of our propane swap agreements and call options, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). The following table presents the changes in the balance of accumulated other comprehensive loss for the years ended December 31, 2014 and 2013. All amounts in the following table are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2013	$(2,533)	$—	$(2,533)
Other comprehensive loss before reclassifications	(3,242)	(482)	(3,724)
Amounts reclassified from accumulated other comprehensive loss	132	449	581
Net current-period other comprehensive loss	(3,110)	(33)	(3,143)
As of December 31, 2014	$(5,643)	$(33)	$(5,676)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2012	$(5,062)	$—	$(5,062)
Other comprehensive income before reclassifications	2,251	—	2,251
Amounts reclassified from accumulated other comprehensive loss	278	—	278
Net current-period other comprehensive income	2,529	—	2,529
As of December 31, 2013	$(2,533)	$—	$(2,533)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the years ended December 31, 2014 and 2013.

For the Year Ended December 31, (in thousands)	2014	2013
Amortization of defined benefit pension and postretirement plan items:		
Prior service cost [(1)]	$58	$60
Net gain [(1)]	(279)	(523)
Total before income taxes	(221)	(463)
Income tax benefit	89	185
Net of tax	$(132)	$(278)
Gains and losses on commodity contracts cash flow hedges		
Propane swap agreements [(2)]	$(735)	$—
Call options [(2)]	(17)	—
Total before income taxes	(752)	—
Income tax benefit	303	—
Net of tax	$(449)	$—

Total reclassifications for the period	$(581)	$(278)

(1) These amounts are included in the computation of net periodic benefits. See Note 16, Employee Benefit Plans, for additional details.

(2) These amounts are included in the effects of gains and losses from derivative instruments. See Note 7, Derivative Instruments, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in operations expense and gains and losses on propane swap agreements and call options are included in cost of sales in the accompanying consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying consolidated statements of income.

16. EMPLOYEE BENEFIT PLANS

We measure the assets and obligations of the defined benefit pension plans and other postretirement benefits plans to determine the plans' funded status as of the end of the year as an asset or a liability on our consolidated balance sheets. We record as a component of other comprehensive income/loss or a regulatory asset the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit costs.

Defined Benefit Pension Plans

We sponsor three defined benefit pension plans: the Chesapeake Pension Plan, the FPU Pension Plan and the Chesapeake SERP.

The Chesapeake Pension Plan was closed to new participants, effective January 1, 1999, and was frozen with respect to additional years of service and additional compensation, effective January 1, 2005. Benefits under the Chesapeake Pension Plan were based on each participant's years of service and highest average compensation, prior to the freezing of the plan.

The FPU Pension Plan covers eligible FPU non-union employees hired before January 1, 2005 and union employees hired before the respective union contract expiration dates in 2005 and 2006. Prior to the merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation, effective December 31, 2009.

The Chesapeake SERP was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant's years of service and highest average compensation, prior to the freezing of the plan.

In January 2011, a former executive officer retired and received lump-sum pension distribution from the Chesapeake Pension Plan. Based upon the funding status of the Chesapeake Pension Plan at the time, which did not meet or exceed 110 percent of the benefit obligation as required per the Department of Labor regulations, our former executive officer was required to deposit property equal to 125 percent of the restricted portion of his lump sum distribution into an escrow. Each year, an amount equal to the value of payments that would have been paid to him if he had elected the life annuity form of distribution becomes unrestricted. Property equal to the life annuity amount is returned to him from the escrow account. These same regulations will apply to the top 20 highest compensated employees taking distributions from the Chesapeake Pension Plan.

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The following schedule sets forth the funded status at December 31, 2014 and 2013 and the net periodic cost for the years ended December 31, 2014, 2013 and 2012 for the Chesapeake and FPU Pension Plans:

	Chesapeake Pension Plan		FPU Pension Plan	
At December 31,	2014	2013	2014	2013
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	$10,268	$11,933	$55,876	$64,512
Interest cost	425	405	2,613	2,367
Actuarial loss (gain)	1,891	(1,092)	12,785	(8,007)
Benefits paid	(603)	(978)	(3,101)	(2,996)
Benefit obligation — end of year	11,981	10,268	68,173	55,876
Change in plan assets:				
Fair value of plan assets — beginning of year	8,743	8,430	44,337	41,954
Actual return on plan assets	305	967	1,485	4,747
Employer contributions	633	324	2,356	632
Benefits paid	(603)	(978)	(3,101)	(2,996)
Fair value of plan assets — end of year	9,078	8,743	45,077	44,337
Reconciliation:				
Funded status	(2,903)	(1,525)	(23,096)	(11,539)
Accrued pension cost	$(2,903)	$(1,525)	$(23,096)	$(11,539)
Assumptions:				
Discount rate	3.50%	4.25%	3.75%	4.75%
Expected return on plan assets	6.00%	6.00%	7.00%	7.00%

	Chesapeake Pension Plan			FPU Pension Plan		
For the Years Ended December 31,	2014	2013	2012	2014	2013	2012
(in thousands)						
Components of net periodic pension cost:						
Interest cost	$425	$405	$458	$2,613	$2,367	$2,577
Expected return on assets	(516)	(486)	(418)	(3,089)	(2,866)	(2,627)
Amortization of prior service cost	—	(1)	(5)	—	—	—
Amortization of actuarial loss	176	322	255	8	330	196
Net periodic pension cost	85	240	290	(468)	(169)	146
Amortization of pre-merger regulatory asset	—	—	—	761	761	761
Total periodic cost	$85	$240	$290	$293	$592	$907
Assumptions:						
Discount rate	4.25%	3.50%	4.25%	4.75%	3.75%	4.50%
Expected return on plan assets	6.00%	6.00%	6.00%	7.00%	7.00%	7.00%

Included in the net periodic costs for the FPU Pension Plan is continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated operations for the changes in funded status that occurred but was not recognized as part of net periodic cost prior to the merger with Chesapeake in October 2009. This was previously deferred as a regulatory asset by FPU prior to the merger to be recovered through rates pursuant to an order by the Florida PSC. The unamortized balance of this regulatory asset was $3.6 million and $4.3 million at December 31, 2014 and 2013, respectively.

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The following sets forth the funded status at December 31, 2014 and 2013 and the net periodic cost for the years ended December 31, 2014, 2013 and 2012 for the Chesapeake SERP:

At December 31,	2014	2013
(in thousands)		
Change in benefit obligation:		
Benefit obligation — beginning of year	$2,210	$2,352
Interest cost	92	81
Actuarial loss (gain)	437	(134)
Benefits paid	(89)	(89)
Benefit obligation — end of year	2,650	2,210
Change in plan assets:		
Fair value of plan assets — beginning of year	—	—
Employer contributions	89	89
Benefits paid	(89)	(89)
Fair value of plan assets — end of year	—	—
Reconciliation:		
Funded status	(2,650)	(2,210)
Accrued pension cost	$(2,650)	$(2,210)
Assumptions:		
Discount rate	3.50%	4.25%

For the Years Ended December 31,	2014	2013	2012
(in thousands)			
Components of net periodic pension cost:			
Interest cost	$92	$81	$90
Amortization of prior service cost	19	19	19
Amortization of actuarial loss	47	64	46
Net periodic pension cost	$158	$164	$155
Assumptions:			
Discount rate	4.25%	3.50%	4.25%

Our funding policy provides that payments to the trustee of each qualified plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2014, 2013 and 2012:

	Chesapeake Pension Plan			FPU Pension Plan		
At December 31,	2014	2013	2012	2014	2013	2012
Asset Category						
Equity securities	51.42%	54.40%	52.07%	52.62%	55.02%	52.81%
Debt securities	37.31%	36.54%	38.00%	37.69%	36.54%	38.04%
Other	11.27%	9.06%	9.93%	9.69%	8.44%	9.15%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The investment policy of both the Chesapeake and FPU Pension Plans is designed to provide the capital assets necessary to meet the financial obligations of the plans. The investment goals and objectives are to achieve investment returns that, together with contributions, will provide funds adequate to pay promised benefits to present and future beneficiaries of the plans, earn a long-term investment return in excess of the growth of the Plans' retirement liabilities, minimize pension expense and cumulative contributions resulting from liability measurement and asset performance, and maintain a diversified portfolio to reduce the risk of large losses.

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The following allocation range of asset classes is intended to produce a rate of return sufficient to meet the Plans' goals and objectives:

Asset Allocation Strategy

Asset Class	Minimum Allocation Percentage	Maximum Allocation Percentage
Domestic Equities (Large Cap, Mid Cap and Small Cap)	14 %	32 %
Foreign Equities (Developed and Emerging Markets)	13 %	25 %
Fixed Income (Inflation Bond and Taxable Fixed)	26 %	40 %
Alternative Strategies (Long/Short Equity and Hedge Fund of Funds)	6 %	14 %
Diversifying Assets (High Yield Fixed Income, Commodities, and Real Estate)	7 %	19 %
Cash	0 %	5 %

Due to periodic contributions and different asset classes producing varying returns, the actual asset values may temporarily move outside of the intended ranges. The investments are monitored on a quarterly basis, at a minimum, for asset allocation and performance.

At December 31, 2014, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy			
Asset Category	Level 1	Level 2	Level 3	Total
(in thousands)				
Equity securities				
U.S. Large Cap [(1)]	$4,069	$4,028	$—	$8,097
U.S. Mid Cap [(1)]	1,733	1,714	—	3,447
U.S. Small Cap [(1)]	873	821	—	1,694
International [(2)]	9,621	—	—	9,621
Alternative Strategies [(3)]	5,531	—	—	5,531
	21,827	6,563	—	28,390
Debt securities				
Fixed income [(4)]	17,717	—	—	17,717
High Yield [(4)]	2,658	—	—	2,658
	20,375	—	—	20,375
Other				
Commodities [(5)]	1,819	—	—	1,819
Real Estate [(6)]	2,427	—	—	2,427
Guaranteed deposit [(7)]	—	—	1,144	1,144
	4,246	—	1,144	5,390
Total Pension Plan Assets	$46,448	$6,563	$1,144	$54,155

(1) Includes funds that invest primarily in United States common stocks.

(2) Includes funds that invest primarily in foreign equities and emerging markets equities.

(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.

(4) Includes funds that invest in investment grade and fixed income securities.

(5) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.

(6) Includes funds that invest primarily in real estate.

(7) Includes investment in a group annuity product issued by an insurance company.

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At December 31, 2013, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy			
Asset Category	Level 1	Level 2	Level 3	Total
(in thousands)				
Equity securities				
U.S. Large Cap [1]	$3,964	$4,118	$—	$8,082
U.S. Mid Cap [1]	—	3,412	—	3,412
U.S. Small Cap [1]	—	1,736	—	1,736
International [2]	10,687	—	—	10,687
Alternative Strategies [3]	5,235	—	—	5,235
	19,886	9,266	—	29,152
Debt securities				
Inflation Protected [4]	2,462	—	—	2,462
Fixed income [5]	—	14,305	—	14,305
High Yield [5]	—	2,629	—	2,629
	2,462	16,934	—	19,396
Other				
Commodities [6]	1,939	—	—	1,939
Real Estate [7]	1,991	—	—	1,991
Guaranteed deposit [8]	—	—	602	602
	3,930	—	602	4,532
Total Pension Plan Assets	$26,278	$26,200	$602	$53,080

(1) Includes funds that invest primarily in United States common stocks.
(2) Includes funds that invest primarily in foreign equities and emerging markets equities.
(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.
(4) Includes funds that invest primarily in inflation-indexed bonds issued by the U.S. government.
(5) Includes funds that invest in investment grade and fixed income securities.
(6) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.
(7) Includes funds that invest primarily in real estate.
(8) Includes investment in a group annuity product issued by an insurance company.

At December 31, 2014 and 2013, all of the investments classified under Level 1 of the fair value measurement hierarchy were recorded at fair value based on unadjusted quoted prices in active markets for identical investments. The Level 2 investments were recorded at fair value based on net asset value per unit of the investments, which used significant observable inputs although those investments were not traded publicly and did not have quoted market prices in active markets. The Level 3 investments were recorded at fair value based on the contract value of annuity products underlining guaranteed deposit accounts, which was calculated using discounted cash flow models. The contract value of these products represented deposits made to the contract, plus earnings at guaranteed crediting rates, less withdrawals and fees.

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The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2014 and 2013:

	For the Year Ended December 31,	
	2014	2013
(in thousands)		
Balance, beginning of year	$602	$710
Purchases	1,811	618
Transfers in	2,390	3,175
Disbursements	(3,704)	(3,966)
Investment income	45	65
Balance, end of year	$1,144	$602

Other Postretirement Benefits Plans

We sponsor two defined benefit plans: the Chesapeake Postretirement Plan and the FPU Medical Plan. In March 2011, new plan provisions for the FPU Medical Plan were adopted in a continuing effort to standardize FPU’s benefits with those offered by Chesapeake. The new plan provisions, which became effective January 1, 2012, require eligible employees retiring in 2012 through 2014 to pay a portion of the total benefit costs based on the year they retire. Participants retiring in 2015 and after will be required to pay the full benefit costs associated with participation in the FPU Medical Plan. The change in the FPU Medical Plan resulted in a curtailment gain of $892,000. Since we determined that the non-recurring gain resulted from the FPU merger and the related integration, we determined that the appropriate accounting treatment for the portion of the gain allocated to FPU's regulated operations prescribed deferral as a regulatory liability and amortization over a future period, as specified by the Florida PSC. We recorded $170,000 of this curtailment gain in 2012, which was allocated to FPU's unregulated operations. We deferred $722,000 of this curtailment gain and included it as a regulatory liability. We amortized and recorded as a credit to amortization expense $212,000 and $510,000 of the deferred curtailment gain during 2014 and 2013, respectively.

The following sets forth the funded status at December 31, 2014 and 2013 and the net periodic cost for the years ended December 31, 2014, 2013, and 2012:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	2014	2013	2014	2013
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	$1,262	$1,415	$1,519	$1,774
Interest cost	39	47	69	63
Plan participants contributions	106	92	97	104
Actuarial loss (gain)	6	(108)	375	(165)
Benefits paid	(175)	(184)	(348)	(257)
Benefit obligation — end of year	1,238	1,262	1,712	1,519
Change in plan assets:				
Fair value of plan assets — beginning of year	—	—	—	—
Employer contributions(1)	69	92	251	153
Plan participants contributions	106	92	97	104
Benefits paid	(175)	(184)	(348)	(257)
Fair value of plan assets — end of year	—	—	—	—
Reconciliation:				
Funded status	(1,238)	(1,262)	(1,712)	(1,519)
Accrued postretirement cost	$(1,238)	$(1,262)	$(1,712)	$(1,519)
Assumptions:				

Discount rate	3.50 %	4.25 %	3.75 %	4.75 %

(1) Chesapeake's Postretirement Plan does not receive a Medicare Part-D subsidy. The FPU Medical Plan did not receive a significant subsidy for the post-merger period.

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Net periodic postretirement benefit costs for 2014, 2013, and 2012 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31,	2014	2013	2012	2014	2013	2012
(in thousands)						
Components of net periodic postretirement cost:						
Service cost	$—	$—	$—	$—	$—	$1
Interest cost	39	47	55	69	63	79
Amortization of:						
Actuarial loss	55	74	73	—	—	—
Prior service cost	(77)	(77)	(77)	—	—	—
Net periodic cost	17	44	51	69	63	80
Curtailment gain	—	—	—	—	—	(892)
Amortization of pre-merger regulatory asset	—	—	—	8	8	8
Net periodic cost	$17	$44	$51	$77	$71	$(804)
Assumptions						
Discount rate	4.25%	3.50%	4.25%	4.75%	3.75%	4.50%

Similar to the FPU Pension Plan, continued amortization of the FPU postretirement benefit regulatory asset related to the unrecognized cost prior to the merger with Chesapeake was included in the net periodic cost. The unamortized balance of this regulatory asset was $46,000 and $54,000 at December 31, 2014 and 2013, respectively.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive income/loss or as a regulatory asset as of December 31, 2014:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$—	$—	$9	$ (832)	$—	$(823)
Net loss	4,410	19,679	1,050	924	233	26,296
Total	$4,410	$19,679	$1,059	$ 92	$233	$25,473
Accumulated other comprehensive loss pre-tax[(1)]	$4,410	$3,739	$1,059	$ 92	$44	$9,344
Post-merger regulatory asset	—	15,940	—	—	189	16,129
Subtotal	4,410	19,679	1,059	92	233	25,473
Pre-merger regulatory asset	—	3,587	—	—	46	3,633
Total unrecognized cost	$4,410	$23,266	$1,059	$ 92	$279	$29,106

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2014 is net of income tax benefits of $3.7 million.

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Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs after the merger with Chesapeake related to its regulated operations, which is included in the above table as post-merger regulatory asset. FPU also continues to maintain and amortize a portion of the unrecognized pension and postretirement benefit costs prior to the merger with Chesapeake related to its regulated operations, which is shown as a pre-merger regulatory asset.

The amounts in accumulated other comprehensive income/loss and recorded as a regulatory asset for our pension and postretirement benefits plans that are expected to be recognized as a component of net benefit cost in 2015 are set forth in the following table:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$—	$—	$9	$ (77)	$—	$(68)
Net loss	$364	$454	$99	$ 70	$6	$993
Amortization of pre-merger regulatory asset	$—	$761	$—	$ —	$8	$769

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations of all the plans were based on the interest rates of high-quality bonds in 2014, reflecting the expected lives of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake's plans and FPU's plans have different expected plan lives and investment policies, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different assumptions regarding discount rate and expected return on plan assets were selected for Chesapeake's and FPU's plans. Since both pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable. We adopted a new mortality table (RP 2014), which was developed by the Society of Actuaries and published during 2014.

The health care inflation rate for 2014 used to calculate the benefit obligation is 5.0 percent for medical and 6.0 percent for prescription drugs for the Chesapeake Postretirement Plan; and 5.5 percent for the FPU Medical Plan. A one–percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately $380,000 as of December 31, 2014, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2014 by approximately $14,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $302,000 as of December 31, 2014, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2014 by approximately $11,000.

Estimated Future Benefit Payments

In 2015, we expect to contribute $475,000 and $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $151,000 to the Chesapeake SERP. We also expect to contribute $79,000 and $207,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2015. The schedule below shows the estimated future benefit payments for each of the plans previously described:

	Chesapeake Pension Plan(1)	FPU Pension Plan(1)	Chesapeake SERP(2)	Chesapeake Postretirement Plan(2)	FPU Medical Plan(2)
(in thousands)					
2015	$642	$2,957	$151	$79	$207
2016	$594	$3,008	$151	$78	$179
2017	$715	$3,022	$150	$75	$151

2018	$637	$3,090	$149	$76	$111
2019	$706	$3,178	$148	$76	$116
Years 2020 through 2024	$3,896	$17,207	$938	$331	$474

(1) The pension plan is funded; therefore, benefit payments are expected to be paid out of the plan assets.
(2) Benefit payments are expected to be paid out of our general funds.

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Retirement Savings Plan

Effective January 1, 2012, we sponsor one 401(k) retirement savings plan and the 401(k) SERP, a non-qualified supplemental executive retirement savings plan.

Our 401(k) plan is offered to all eligible employees who have completed three months of service, except for employees represented by a collective bargaining agreement that does not specifically provide for participation in the plan, non-resident aliens with no U.S. source income and individuals classified as consultants, independent contractors or leased employees. Effective January 1, 2011, we match 100 percent of eligible participants' pre-tax contributions to the Chesapeake 401(k) plan up to a maximum of six percent of eligible compensation. In addition, we may make a supplemental contribution to participants in the plan, without regard to whether or not they make pre-tax contributions. Beginning January 1, 2011, the employer matching contribution is made in cash and is invested based on a participant's investment directions. Any supplemental employer contribution is generally made in Chesapeake stock. With respect to the employer match and supplemental employer contribution, employees are 100 percent vested after two years of service or upon reaching 55 years of age while still employed by Chesapeake. Employees with one year of service are 20 percent vested and will become 100 percent vested after two years of service. Employees who do not make an election to contribute or do not opt out of the Chesapeake 401(k) plan will be automatically enrolled at a deferral rate of three percent, and the automatic deferral rate will increase by one percent per year up to a maximum of six percent.

We also offer the 401(k) SERP to our executive officers over a specific income threshold. Participants receive a cash-only matching contribution percentage equivalent to their 401(k) match level. All contributions and matched funds can be invested among the mutual funds available for investment. All obligations arising under the 401(k) SERP are payable from our general assets, although we have established a Rabbi Trust for the 401(k) SERP. Assets held in the Rabbi Trust for the 401(k) SERP had a fair value of $3.7 million and $3.1 million at December 31, 2014 and 2013, respectively. (See Note 9, Investments, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Contributions to all of our 401(k) plans totaled $4.1 million, $3.7 million and $2.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, there are 855,975 shares of our common stock reserved to fund future contributions to the 401(k) plan.

Deferred Compensation Plan

On December 7, 2006, the Board of Directors approved the Deferred Compensation Plan as amended, effective January 1, 2007. At December 31, 2014, the Deferred Compensation Plan consisted of shares of our common stock related to the deferral of executive performance shares, directors' stock retainers and director cash retainers and fees. Participants in the Deferred Compensation Plan are able to elect the payment of benefits to begin on a specified future date after the election is made in the form of a lump sum or annual installments. Deferrals of executive cash bonuses and directors' cash retainers and fees are paid in cash. All deferrals of executive performance shares, which represent deferred stock units, and directors' stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares. We established a Rabbi Trust in connection with the Deferred Compensation Plan. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the consolidated balance sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled $1.3 million and $1.1 million at December 31, 2014 and 2013, respectively.

Effective January 1, 2014, our 401(k) SERP was amended, restated and renamed as the Chesapeake Utilities Corporation Non-Qualified Deferred Compensation Plan. In addition, the Deferred Compensation Plan was consolidated into this plan. As a result of these actions, the 401(k) SERP and the Deferred Compensation Plan are now administered as a single plan.

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17. SHARE-BASED COMPENSATION PLANS
Since May 2, 2013, our non-employee directors and key employees have been granted share-based awards through our SICP. Prior to May 2, 2013, they were awarded share-based awards through DSCP and 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 the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period. We have 621,176 shares reserved for issuance under the SICP.
The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the SICP for the years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31,		
	2014	2013	2012
(in thousands)			
Awards to non-employee directors	$540	$478	$443
Awards to key employees	1,418	1,153	976
Total compensation expense	1,958	1,631	1,419
Less: tax benefit	(790)	(657)	(569)
Share-Based Compensation amounts included in net income	$1,168	$974	$850

Stock Options
We did not have any stock options outstanding at December 31, 2014, or 2013, nor were any stock options issued during 2014, 2013 and 2012.
Non-employee Directors
Shares granted to non-employee directors are issued in advance of the directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2014, each of our non-employee directors received an annual retainer of 1,209 shares of common stock under the SICP as of December 31, 2014.
A summary of stock activity for our non-employee directors for the years ended December 31, 2014, 2013 and 2012 is presented below.

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2012	—	$ —
Granted	14,141	$ 34.99
Vested	14,141	$ 34.99
Outstanding — December 31, 2013	—	$ —
Granted [1]	13,827	$ 41.60
Vested [1]	13,827	$ 41.60
Outstanding — December 31, 2014	—	$ —

[1] In November 2014, we added a new member to our Board of Directors. The number of shares granted to the director for his annual retainer was prorated.
The weighted average grant date fair value of shares granted to our non-employee directors during 2014, 2013 and 2012 was $41.60, $34.99 and $27.37 per share, respectively. The intrinsic values of the shares granted to our non-employee directors are equal to the fair value of these awards on the date of grant. At December 31, 2014, there was $201,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2015, which approximates the expected remaining service period of those directors.
Key Employees
Our Compensation Committee is authorized to grant key employees of the Company the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals. These awards are subject to certain post-vesting transfer restrictions.

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We currently have multi-year performance plans, which are based upon the successful achievement of long-term goals, growth and financial results, which comprised both market-based and performance-based conditions or targets. The fair value of each share of stock tied to a performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share of market-based award granted.

The table below presents the summary of the stock activity for awards to key employees:

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2012	126,968	$25.24
Granted	35,237	$29.90
Vested	36,498	$22.17
Expired	4,565	$26.08
Outstanding — December 31, 2013	121,142	$28.20
Granted	41,442	$39.99
Vested	39,546	$26.87
Outstanding — December 31, 2014	123,038	$32.60

In 2014, 2013 and 2012, we withheld shares with value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives receiving the net shares. The total number of shares withheld of 12,687, 15,617 and 8,505 for 2014, 2013 and 2012, respectively, was based on the value of the shares on their vesting date, determined by the average of high and low of our stock price. Total payments for the employees' tax obligations to the taxing authorities were approximately $503,000, $519,000, and $238,000, in 2014, 2013 and 2012, respectively. The tax benefit for 2014, 2013 and 2012 is $398,000, 202,000 and 172,000, respectively, and is included in additional paid-in capital in the consolidated statements of stockholders' equity.

The weighted average grant-date fair value of shares awards granted to key employees during 2014, 2013 and 2012 was $39.99, $29.90 and $26.41 per share, respectively. The intrinsic value of these awards was $6.1 million, $4.8 million and $3.8 million for 2014, 2013 and 2012, respectively. At December 31, 2014, there was of $1.2 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2015 and 2016.

18. RATES AND OTHER REGULATORY ACTIVITIES

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

Delaware

There were no significant rates and other regulatory activities in Delaware during 2014.

Maryland

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

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Cecil County expansion: On October 7, 2014, Chesapeake’s Maryland Division filed with the Maryland PSC for expansion of its service territory in Cecil County, Maryland to extend south of the Chesapeake and Delaware Canal in order to serve an industrial customer near Warwick, Maryland. On November 12, 2014, the Maryland PSC granted Chesapeake’s request, conditioned on no adverse comments being received within thirty days. On December 11, 2014, the conditional order approving the request became final.

Florida
Natural gas depreciation study: On January 13, 2014, FPU's natural gas distribution divisions and Chesapeake's Florida natural gas distribution division filed a consolidated natural gas depreciation study with the Florida PSC. We also filed for approval to establish a regulatory asset and related amortization to address the costs associated with the development of this study. The Florida PSC approved new depreciation rates at the Agenda Conference on November 25, 2014. New rates became effective retroactive to January 1, 2014. The new depreciation rates resulted in a reduction of approximately $1.0 million in annual depreciation expense. The Florida PSC also approved amortization of a regulatory asset related to the costs associated with the development of this depreciation study.

Electric rate case: On April 28, 2014, FPU filed a base rate case for its electric distribution operation. FPU requested interim rate relief of approximately $2.4 million and final rate relief of approximately $5.9 million. The interim rate relief requested was based on the twelve-month period ended September 30, 2013. At the July 10, 2014 Agenda Conference, the Florida PSC approved interim rate relief of approximately $2.2 million. The interim rates were effective for meter readings on or after August 10, 2014. On August 29, 2014, FPU and the Florida Office of Public Counsel reached a settlement agreement, which provided, among other things, an increase in annual base rates of approximately $3.8 million and a rate of common equity return of 10.25 percent. On September 15, 2014, the Florida PSC approved the settlement agreement. New final rates were effective for all meter readings on or after November 1, 2014.
PPA with Eight Flags: On September 26, 2014, FPU filed a PPA with the Florida PSC pursuant to which FPU proposes to purchase up to 20 megawatts of electricity from its affiliate, Eight Flags, to service its customers in the Northeast division. Eight Flags is pursuing the development and construction of a CHP plant in Nassau County, Florida. FPU expects the PPA to provide significant savings in fuel costs over its 20-year term, which FPU will pass on to its customers. The Florida PSC approved this agreement at the Agenda Conference on December 18, 2014
Other Matters: We also had developments in the following regulatory matters in Florida:

On November 15, 2013, Chesapeake's Florida natural gas distribution division petitioned the Florida PSC for an extension to its surcharge to recover an additional $381,000 in estimated remaining environmental cleanup costs that have not yet been recovered. The Florida PSC approved the extension of the surcharge and the additional amount for recovery at the Agenda Conference on January 7, 2014. This extension is effective for two years, beginning January 1, 2014.

On September 30, 2014, FPU filed for approval with the Florida PSC two contracts with its Peninsula Pipeline affiliate for additional natural gas transportation services in Nassau and Palm Beach Counties, Florida. The Florida PSC approved these two contracts at the Agenda Conference on December 18, 2014.
Eastern Shore
The following are regulatory activities involving FERC orders applicable to Eastern Shore and the expansions of Eastern Shore’s transmission system:
White Oak Mainline Expansion Project: On November 21, 2014, Eastern Shore submitted to the FERC an application for a CP seeking authorization to construct, own, operate and maintain the White Oak mainline expansion project. The project is designed to provide 45,000 Dts/d of firm transportation service to an industrial customer in Kent County, Delaware. Eastern Shore proposes to construct approximately 7.2 miles of 16-inch diameter pipeline looping in

Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore's existing Delaware City Compressor Station in New Castle County, Delaware. The estimated cost of the project is $29.8 million.

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

TETLP Expansion Project: On January 31, 2014, Eastern Shore submitted to the FERC a request for prior notice authorization regarding a project that included certain improvements at Eastern Shore's existing interconnection with TETLP near Honey Brook, Pennsylvania. This project allows Eastern Shore to increase its capacity to receive natural gas from TETLP by 57,000 Dts/d to a total capacity of 107,000 Dts/d; however, this project does not result in an increase in Eastern Shore's overall system capacity. On April 8, 2014, the FERC approved Eastern Shore's prior notice application, and Eastern Shore made this additional receipt point capacity available to an existing industrial customer.
White Oak Lateral Project Filing: On June 13, 2013, Eastern Shore submitted to the FERC an application for a CP, seeking authorization to construct the White Oak lateral project located in Kent County, Delaware. The project consisted of installing approximately 5.5 miles of 16-inch diameter pipeline, metering facilities and miscellaneous appurtenances, extending from Eastern Shore's mainline system near its North Dover City Gate Station to the Garrison Oak Technical Park, all located in Dover, Delaware. This project was designed to provide 55,200 Dts/d of delivery lateral firm transportation service to an industrial customer facility that was under construction. The total cost of the project was approximately $11.5 million, $2.5 million of which was received from a state grant. The FERC issued a CP for this project, and a notice to allow construction to proceed. Eastern Shore completed construction activities for this project and service commenced on October 1, 2014.

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

19. ENVIRONMENTAL COMMITMENTS AND CONTINGENCIES

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate at current and former operating sites the effect on the environment of the disposal or release of specified substances.
We have participated in the investigation, assessment or remediation, and have exposures at six former MGP sites. Those sites are located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. In January 2015, DNREC issued a report on a former MGP site located in Seaford, Delaware regarding groundwater contamination. We have also been in discussions with the MDE regarding another former MGP site located in Cambridge, Maryland.
As of December 31, 2014, we had approximately $10.1 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, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to all of its MGP sites, approximately $9.7 million of which has been recovered as of December 31, 2014, leaving approximately $4.3 million in regulatory assets for future recovery of environmental costs from FPU's customers.
In addition to the FPU MGP sites, we had $382,000 in environmental liabilities at December 31, 2014, related to Chesapeake's MGP sites in Salisbury, Maryland and Winter Haven, Florida, representing our estimate of future costs associated with these sites. As of December 31, 2014, we had approximately $313,000 in regulatory and other assets for future recovery through Chesapeake's rates.
We did not have any environmental liability related to the former MGP sites in Seaford, Delaware and Cambridge, Maryland at December 31, 2014.
Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental

remediation and related activities, including any potential future remediation costs associated with the two former MGP sites under discussion, for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

The following discussion provides details on MGP sites:

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated a MGP. FPU is currently implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. It is anticipated that similar remedial actions ultimately will be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP at this site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of December 31, 2014, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

In December 2014, the EPA issued a Preliminary Close Out Report, documenting the completion of all physical remedial construction activities at the Sanford site. Groundwater monitoring and statutory Five-Year Reviews to ensure performance of the approved remedy will continue on this site. The total cost of the final remedy is estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement.

As of December 31, 2014, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be $24,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site, as provided in the Third Participation Agreement, or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of December 31, 2014.

Key West, Florida

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

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

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

Pensacola, Florida

FPU formerly owned and operated a MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the FDOT. In October 2009, FDEP informed Gulf Power that it would approve a conditional No Further Action determination for the site with the requirement for institutional and engineering controls. A Memorandum of Understanding was executed on June 16, 2014 between FDOT and FDEP to implement site closure with approved institutional and engineering controls for the site. It is anticipated that FPU’s share of remaining legal and cleanup costs will not exceed $5,000.

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Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. On September 12, 2014, FDEP issued a letter approving shut-down of the sparging operations on the northern portion of the site, contingent upon continued semi-annual monitoring.

Groundwater monitoring results on the southern portion of this site indicate that Natural Attenuation Default Criteria continue to be exceeded. Plans to modify the monitoring network on the southern portion of the site in order to collect additional data to support the development of a remedial plan were specified in a letter to FDEP, dated October 17, 2014. The well installation and abandonment program was implemented in October 2014, and documentation will be reported in the next Semi-Annual RAP Implementation Status Report, which will be submitted in January of 2015. Although specific remedial actions have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $443,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

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

Salisbury, Maryland

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

Other

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

In a letter dated December 5, 2013, the DNREC notified us that it will be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued during January 2015, DNREC provided the evaluation of this site, which found contaminants impacting the groundwater. Shallow groundwater was also impacted by low levels of metals above the DNREC screening levels. Based on these findings, further tests and investigations are required to delineate the extent of soil and groundwater impact associated with site. Subsequent to this report, we estimated the cost of potential remedial actions based on the findings of the report to be $273,000 to $465,000.

20. OTHER COMMITMENTS AND CONTINGENCIES

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. For our Delaware and Maryland natural gas distribution divisions, we 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, we entered into a new contract with a different company to perform similar asset management functions. The new contract expires on March 31, 2017.

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

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC over a six-year term. Sharp's current annual commitment is estimated at approximately 6.5 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC,

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and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

Chesapeake's Florida natural gas distribution division has firm transportation service contracts with FGT and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay the capacity charge.

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

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) 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 nine 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 providing an irrevocable letter of credit. As of December 31, 2014, FPU was in compliance with all of the requirements of its fuel supply contracts.

The total purchase obligations for natural gas, electric and propane supplies are $78.6 million for 2015, $98.7 million for 2016-2017, $87.1 million for 2018-2019 and $121.0 million thereafter.

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 $50.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest of which are for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that PESCO or Xeron defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2014 was $31.6 million, with the guarantees expiring on various dates through December 30, 2015.

Chesapeake guarantees the payment of FPU's first mortgage bonds. The maximum exposure under the guarantee is the outstanding principal and accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 12, Long-Term Debt, for further details).

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2015, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on October 31, 2015, 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 to $40,000 to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of December 31, 2014. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

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

On July 25, 2014, we provided a letter to the Florida PSC guaranteeing potential refunds from interim rates to be charged by our Florida electric operation (see Note 18, Rates and Other Regulatory Activities, for further details on the Florida electric rate case). This guarantee expired in October 2014 upon approval of the permanent rate increase by the Florida PSC and its determination that no refunds from interim rates were required.

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 December 31, 2014, we maintained a liability of $100,000 related to unrecognized income tax benefits and $724,000 related to contingencies for taxes other than income. As of December 31, 2013, we maintained a liability of $300,000 related to unrecognized income tax benefits and $1.0 million related to contingencies for taxes other than income.

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Other

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

21. QUARTERLY FINANCIAL DATA (UNAUDITED)

In our opinion, the quarterly financial information shown below includes all adjustments necessary for a fair presentation of the operations for such periods. Due to the seasonal nature of our business, there are substantial variations in operations reported on a quarterly basis.

	For the Quarters Ended			
	March 31	June 30	September 30	December 31
(in thousands except per share amounts)				
2014 [(1)]				
Operating Revenues	$186,337	$100,497	$91,619	$120,380
Operating Income	$31,623	$10,457	$7,792	$12,408
Net Income	$17,681	$5,134	$3,180	$10,097
Earnings per share:				
Basic	$1.22	$0.35	$0.22	$0.69
Diluted	$1.21	$0.35	$0.22	$0.69
2013 [(1)]				
Operating Revenues	$140,729	$94,146	$86,545	$122,887
Operating Income	$26,550	$9,152	$8,720	$18,312
Net Income	$14,869	$4,356	$3,879	$9,683
Earnings per share:				
Basic	$1.03	$0.30	$0.27	$0.67
Diluted	$1.03	$0.30	$0.27	$0.67

[(1)] The sum of the four quarters does not equal the total year due to rounding.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer, with the participation of other Company officials, have evaluated our “disclosure controls and procedures” (as such term is defined under Rule 13a-15(e) and 15d – 15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2014. Based upon their evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2014.

CHANGE IN INTERNAL CONTROLS

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2014, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

CEO AND CFO CERTIFICATIONS

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. In addition, on June 4, 2014, our Chief Executive Officer certified to the NYSE that he was not aware of any violation by us of the NYSE corporate governance listing standards.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company’s internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records which in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, our management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in an updated report entitled “Internal Control — Integrated Framework,” issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management has evaluated and concluded that our internal control over financial reporting was effective as of December 31, 2014.

Our independent auditors, Baker Tilly Virchow Krause, LLP, have audited and issued their report on effectiveness of our internal control over financial reporting. That report appears on the following page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

We have audited Chesapeake Utilities Corporation's (the "Company") internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") (2013 framework). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by COSO (2013 framework).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets, statements of income, comprehensive income, stockholders' equity, and cash flows of the Company and our report dated March 5, 2015 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
March 5, 2015

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ITEM 9B. OTHER INFORMATION.
None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANACE.
The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned "Election of Directors (Proposal 1)," "Information Concerning Nominees and Continuing Directors," "Corporate Governance," "Committees of the Board – Audit Committee" and "Section 16(a) Beneficial Ownership Reporting Compliance," to be filed no later than March 31, 2015, in connection with our Annual Meeting to be held on or about May 6, 2015.
The information required by this Item with respect to executive officers is, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, set forth in this report following Item 4, as Item 4A Executive Officers of the Registrant.
We have adopted a Code of Ethics for Financial Officers, which applies to our principal executive officer, president, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The information set forth under Item 1 hereof concerning the Code of Ethics for Financial Officers is filed herewith.

ITEM 11. EXECUTIVE COMPENSATION.
The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned "Director Compensation," "Executive Compensation" and "Compensation Discussion and Analysis" in the Proxy Statement to be filed no later than March 31, 2015, in connection with our Annual Meeting to be held on or about May 6, 2015.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.
The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned "Security Ownership of Certain Beneficial Owners and Management" to be filed no later than March 31, 2015, in connection with our Annual Meeting to be held on or about May 6, 2015.

The following table sets forth information, as of December 31, 2014, with respect to our SICP, under which shares of Chesapeake common stock are authorized for issuance:

	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	—	—	621,176
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	621,176

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned, "Corporate Governance," to be filed no later than March 31, 2015 in connection with our Annual Meeting to be held on or about May 6, 2015.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

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The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned “Fees and Services of Independent Registered Public Accounting Firm,” to be filed no later than March 31, 2015, in connection with our Annual Meeting to be held on or about May 6, 2015.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.
The following documents are filed as part of this report:
(a)(1) All of the financial statements, reports and notes to the financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

(a)(2) Report of Independent Registered Public Accounting Firm; and Schedule II—Valuation and Qualifying Accounts.
(a)(3) The Exhibits below.

• Exhibit 3.1	Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
• Exhibit 3.2	Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2012, are incorporated herein by reference to Exhibit 3 of our Current Report on Form 8-K, filed December 7, 2012, File No. 001-11590.
• Exhibit 3.3	Amendment to Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2014, is filed herewith.
• Exhibit 4.1	Form of Indenture between Chesapeake Utilities Corporation and Boatmen’s Trust Company, as Trustee, relating to its 8 1/4% Convertible Debentures, is incorporated herein by reference to Exhibit 4.2 of our Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.
• Exhibit 4.2	Note Purchase Agreement dated December 27, 2000, between Chesapeake Utilities Corporation, as issuer, and Pacific Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation’s 7.83% Senior Notes. †
• Exhibit 4.3	Note Agreement dated October 31, 2002, between Chesapeake Utilities Corporation, as issuer, and Massachusetts Mutual Life Insurance Company, C.M. Life Insurance Company, American United Life Insurance Company, Pioneer Mutual Life Insurance Company and The State Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation’s 6.64% Senior Notes due 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.
• Exhibit 4.4	Note Agreement dated October 18, 2005, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management, Inc., relating to the private placement of Chesapeake Utilities Corporation’s 5.5% Senior Notes due 2020, is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K

	for the year ended December 31, 2005, File No. 001-11590.
• Exhibit 4.5	Note Agreement dated October 31, 2008, among Chesapeake Utilities Corporation, as issuer, General American Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake's 5.93% Senior Notes due 2023.†
• Exhibit 4.6	Note Agreement dated June 29, 2010, among Chesapeake Utilities Corporation, as issuer, Metropolitan Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.68% Senior Notes due 2026 and Chesapeake Utilities Corporation's 6.43% Senior Notes due 2028.†
• Exhibit 4.7	Note Agreement dated September 5, 2013, among Chesapeake Utilities Corporation, as issuer, and certain note holders, relating to the private placement of Chesapeake Utilities Corporation's 3.73% Senior Notes due 2028 and Chesapeake Utilities Corporation's 3.88% Senior Notes due 2029.†

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• Exhibit 4.8	Form of Indenture of Mortgage and Deed of Trust dated September 1, 1942, between Florida Public Utilities Company and the trustee, for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.
• Exhibit 4.9	Seventeenth Supplemental Indenture dated April 12, 2011, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2011, File No. 001-11590.
• Exhibit 4.10	Sixteenth Supplemental Indenture dated December 1, 2009, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is incorporated herein by reference to Exhibit 4.9 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 4.11	Thirteenth Supplemental Indenture dated June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
• Exhibit 10.1*	Chesapeake Utilities Corporation Cash Bonus Incentive Plan, dated January 1, 2005, is incorporated herein by reference to Exhibit 10.3 of our Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-11590.
• Exhibit 10.2*	Chesapeake Utilities Corporation Directors Stock Compensation Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
• Exhibit 10.3*	Chesapeake Utilities Corporation Employee Stock Award Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
• Exhibit 10.4*	Chesapeake Utilities Corporation Performance Incentive Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
• Exhibit 10.5*	Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan, effective May 2, 2013 is incorporated herein by reference to our Proxy Statement dated March 29, 2013 in connection with our Annual Meeting held on May 2, 2013, File No. 0000019745.

• Exhibit 10.6*	Chesapeake Utilities Corporation Deferred Compensation Plan, amended and restated as of January 1, 2009, is incorporated herein by reference to Exhibit 10.5 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
• Exhibit 10.7*	First Amendment to the Chesapeake Utilities Corporation Deferred Compensation Plan, dated December 28, 2010, is incorporated herein by reference to Exhibit 10.6 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 10.8*	Non-Qualified Deferred Compensation Plan, effective January 1, 2014, is incorporated herein by reference to Exhibit 10.8 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
• Exhibit 10.9*	Consulting Agreement dated January 2, 2013, between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.7 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.10*	Executive Employment Agreement dated January 14, 2011, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
• Exhibit 10.11*	Amendment to Executive Employment Agreement effective January 1, 2014, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 14, 2014, File No. 001-11590.
• Exhibit 10.12*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.9 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.

• Exhibit 10.13*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.10 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.14*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Elaine B. Bittner, incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.15*	Executive Employment Agreement dated January 1, 2015, between Chesapeake Utilities Corporation and Jeffry M. Householder, is filed herewith.
• Exhibit 10.16*	Form of Performance Share Agreement, effective January 5, 2012 for the period 2012 to 2014, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 5, 2012, File No. 001-11590.
• Exhibit 10.17*	Form of Performance Share Agreement, effective January 8, 2013 for the period 2013 to 2015, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.18*	Form of Performance Share Agreement, effective January 7, 2014 for the period 2014 to 2016, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, and Jeffry M. Householder is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
• Exhibit 10.19*	Form of Performance Share Agreement, effective January 13, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner and Jeffry M. Householder, is filed herewith.
• Exhibit 10.20*	Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
• Exhibit 10.21*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is incorporated

	herein by reference to Exhibit 10.30 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 10.22*	Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.28 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
• Exhibit 10.23*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, dated October 28, 2010, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2010, File No. 001-11590.
• Exhibit 10.24*	Second Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, effective January 1, 2012, is incorporated herein by reference to Exhibit 10.20 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.25	Revolving Credit Agreement dated December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is filed herewith.
• Exhibit 10.26	Promissory Note, contained as an exhibit to the Revolving Credit Agreement dated December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is filed herewith.
• Exhibit 12	Computation of Ratio of Earning to Fixed Charges is filed herewith.
• Exhibit 14.1	Code of Ethics for Financial Officers is filed herewith.

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- Exhibit 14.2 Business Code of Ethics and Conduct is filed herewith.
- Exhibit 21 Subsidiaries of the Registrant is filed herewith.
- Exhibit 23.1 Consent of Independent Registered Public Accounting Firm is filed herewith.
- Exhibit 31.1 Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), dated March 5, 2015, is filed herewith.
- Exhibit 31.2 Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), dated March 5, 2015, is filed herewith.
- Exhibit 32.1 Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 5, 2015 is filed herewith.
- Exhibit 32.2 Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 5, 2015, is filed herewith.
- Exhibit 101.INS XBRL Instance Document is filed herewith.
- Exhibit 101.SCH XBRL Taxonomy Extension Schema Document is filed herewith.
- Exhibit 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document is filed herewith.
- Exhibit 101.DEF XBRL Taxonomy Extension Definition Linkbase Document is filed herewith.
- Exhibit 101.LAB XBRL Taxonomy Extension Label Linkbase Document is filed herewith.
- Exhibit 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document is filed herewith.

* Management contract or compensatory plan or agreement.

† These agreements have not been 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 copies to the SEC upon request.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, Chesapeake Utilities Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

By: /s/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President and Chief Executive Officer
Date: March 5, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/S/ RALPH J. ADKINS
Ralph J. Adkins,
Chairman of the Board and Director
Date: March 5, 2015

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director
Date: March 5, 2015

/S/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
Date: March 5, 2015

/S/ EUGENE H. BAYARD,ESQ
Eugene H. Bayard, Esq., Director
Date: March 5, 2015

/S/ RICHARD BERNSTEIN
Richard Bernstein, Director
Date: March 5, 2015

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
Date: March 5, 2015

/S/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
Date: March 5, 2015

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
Date: March 5, 2015

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
Date: March 5, 2015

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
Date: March 5, 2015

/S/ JOSEPH E. MOORE, ESQ
Joseph E. Moore, Esq., Director
Date: March 5, 2015

/S/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
Date: March 5, 2015

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
Date: March 5, 2015

/S/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Vice Chairman of Board and Director
Date: March 5, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

The audit referred to in our report dated March 5, 2015 relating to the consolidated financial statements of Chesapeake Utilities Corporation (the "Company") as of December 31, 2014 and 2013 and for each of the years in the three-year period ended December 31, 2014, which is contained in Item 8 of this Form 10-K, also included the audits of the financial statement schedule listed in Item 15(a)2. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statement schedule based on our audits.

In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
March 5, 2015

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Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions		Deductions [2]	Balance at End of Year
		Charged to Income	Other Accounts [1]		
(In thousands)					
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2014	$1,635	$1,073	$85	(1,673)	$1,120
2013	$826	$1,796	$249	(1,236)	$1,635
2012	$1,090	$826	$354	(1,444)	$826

(1) Recoveries.
(2) Uncollectible accounts charged off.