CHESAPEAKE UTILITIES CORP
Form 10-K
March 07, 2012
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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, 2011

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

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

909 Silver Lake Boulevard, Dover, Delaware 19904

(Address of principal executive offices, including zip code)

302-734-6799

(Registrant s telephone number, including area code)

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 x.

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 x.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x. No ¨.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x. No ¨.

Indicate by check mark 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. x

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	x
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 x.

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2011, 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 $382.8 million.

As of February 29, 2012, 9,576,780 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2012 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

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CHESAPEAKE UTILITIES CORPORATION

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GLOSSARY OF KEY TERMS AND DEFINITIONS

Accounting Principles Generally Accepted in the United States of America (GAAP): A standard framework of accounting rules used to prepare, present and report financial statements in the United States of America.

Acquisition adjustment: The recovery, through rates, and inclusion in rate base of the premium paid for an acquisition as approved by the state PSCs for the regulated operations.

Allowed return: Return on equity or pre-tax, pre-interest rate of return on investment approved by the state PSCs or the FERC for the respective regulated operations.

BravePoint®, Inc. (BravePoint): An advanced information services subsidiary, headquartered in Norcross, Georgia. BravePoint is a wholly owned subsidiary of Chesapeake Services Company, which is a wholly owned subsidiary of Chesapeake.

Chesapeake s legacy business: Chesapeake s businesses, exclusive of FPU. We use this term to highlight our organic growth and assist the readers with the comparable results of operations between 2010 and 2009 from businesses that Chesapeake owned prior to the FPU acquisition.

Chesapeake Utilities Corporation (Chesapeake or the Company): The Registrant, its divisions, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure.

Come-Back filing: The regulatory filing that was required by the Florida PSC within 18 months of the completion of the FPU merger to detail known benefits, synergies, cost savings and cost increases resulting from the merger.

Cooling Degree-Day (CDD): A measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit. This measurement is used to determine the impact of hot weather on our electric distribution operation during the cooling season.

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

Dekatherms (Dts): A natural gas unit of measurement that includes a standard measure for heating value. A dekatherm (or 10 therms) of gas contains 10,000 British thermal units of heat, or the energy equivalent of burning approximately 100 cubic feet of natural gas under normal conditions.

Dekatherms per day (Dts/d): Natural gas volume in dekatherms measured on a daily basis.

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

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

Eastern Shore Natural Gas Company (Eastern Shore): a wholly owned natural gas transmission subsidiary of Chesapeake. Eastern Shore operates an interstate pipeline system that transports natural gas from various points in Pennsylvania to customers in southern Pennsylvania and on the Delmarva Peninsula.

Federal Energy Regulatory Commission (FERC): An independent agency of the Federal government that regulates the interstate transmission of electricity, natural gas, and oil. The FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines. Eastern Shore is regulated by the FERC.

Firm service: Customers whose gas supply will not be disrupted to meet the needs of other customers. Typically, this class of customer comprises residential customers and most commercial customers.

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

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Florida Public Utilities Company (FPU): a wholly owned subsidiary of Chesapeake as of October 28, 2009, the date we acquired FPU through the merger. FPU provides natural gas, electric and propane distribution services in Florida.

Gross Margin: A non-GAAP measure, which Chesapeake uses to evaluate the performance of its business segments. Gross margin is calculated by deducting the cost of sales from operating revenues.

Heating Degree-Day (HDD): 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. This measurement is used to determine the impact of cold weather on our natural gas, electric and propane distribution operations during the heating season.

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

Lower of Cost or Market: The process of adjusting inventory in order to reflect the lesser of its original cost or its current market value.

Manufactured Gas Plant (MGP): The sites that previously used coal to manufacture gaseous fuel that was used for industrial, commercial and residential use. These sites are currently undergoing remedial action plans to remove contaminations in the soil and water at or near these sites.

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

Normal Weather: An average equal to the most recent 10 year average of heating and/or cooling degree-days.

Peninsula Pipeline Company, Inc. (Peninsula Pipeline): A wholly owned Florida intrastate pipeline subsidiary of Chesapeake.

Performance Incentive Plan (PIP): A program that grants key employees of Chesapeake the right to receive awards of shares of common stock, contingent upon the achievement of established performance goals.

Peninsula Energy Services Company, Inc. (PESCO): A wholly owned natural gas marketing subsidiary of Chesapeake. 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.

Peoples Gas: The Peoples Gas System division of Tampa Electric Company.

ProfitZoom : A new product developed and launched by BravePoint. ProfitZoom is an integrated system encompassing financial, job costing and service management modules, which was designed specifically for the fire protection and specialty contracting industries.

Public Service Commission (PSC): The state regulatory agencies that regulate Chesapeake s natural gas and electric distribution operations as to their rates and service. Chesapeake s natural gas operations operate in Delaware, Maryland and Florida and are regulated by the PSCs in those states. Chesapeake s electric operation operates in Florida and is regulated by the Florida PSC. Peninsula Pipeline is also regulated by the Florida PSC.

Purchased fuel cost recovery mechanism: A regulatory method of adjusting the billing rates to reflect changes in the cost of purchased fuel for the natural gas and electric distribution operations. This allows matching of revenues with natural gas and electric supply and transportation costs and typically provides full recovery of such costs.

Rate Case: A periodic filing with the state PSC or the FERC to establish equitable rates and balance the interests of all classes of customers and shareholders.

Remedial Action Plan (RAP): Procedures taken or being considered in removing contaminants from a MGP formerly owned or operated by Chesapeake or FPU.

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Sharp Energy, Inc. (Sharp): a wholly owned propane distribution subsidiary of Chesapeake. Sharp and its subsidiary, Sharpgas, Inc., provide propane distribution service in Delaware, Maryland, Pennsylvania and Virginia.

Tariffs: Documents issued by the regulatory agencies in each jurisdiction that establish the rates that Chesapeake and its regulated subsidiaries/operations may charge and the practices it must follow when providing utility service to our customers.

Xeron, Inc. (Xeron): a wholly owned propane wholesale marketing subsidiary of Chesapeake, 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, its divisions and/or its wh 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, c potential, forecast or other similar words, or future or conditional verbs such as may, will, should, would or could. These statements re 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 that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries (including deregulation);
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates;
- 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 and ice storms;
- 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;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- declines in the market prices of equity securities and resultant cash funding requirements for our defined benefit pension plans;

the creditworthiness of counterparties with which we are engaged in transactions;

growth in opportunities for our business units;

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 manage and maintain key customer relationships;

the ability to maintain 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;

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- the ability to construct facilities at or below estimated costs;
- changes in technology affecting our advanced information services business; and
- operation and litigation risks that may not be covered by insurance.

ITEM 1. BUSINESS.

(a) Overview

We are a diversified utility company engaged in various energy and other businesses. Chesapeake is a Delaware corporation that was formed in 1947. On October 28, 2009, we completed a merger with Florida Public Utilities Company (FPU), pursuant to which FPU became a wholly owned subsidiary of Chesapeake. We operate regulated energy businesses through our natural gas distribution divisions in Delaware, Maryland and Florida, natural gas and electric distribution operations in Florida through FPU, and natural gas transmission operations on the Delmarva Peninsula and Florida through our subsidiaries, Eastern Shore Natural Gas Company (Eastern Shore) and Peninsula Pipeline Company, Inc. (Peninsula Pipeline), respectively. Our unregulated businesses include our natural gas marketing operation through Peninsula Energy Services Company, Inc. (PESCO); propane distribution operations through Sharp Energy, Inc. and its subsidiary Sharpgas, Inc. (collectively Sharp) and FPU s propane distribution subsidiary, Flo-Gas Corporation; and our propane wholesale marketing operation through Xeron, Inc. (Xeron). We also have an advanced information services subsidiary, BravePoint®, Inc. (BravePoint).

(b) Operating Segments

We are composed of three operating segments:

- *Regulated Energy*. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and service, by the Public Service Commission (PSC) having jurisdiction in each operating territory or by the Federal Energy Regulatory Commission (FERC) in the case of Eastern Shore.
- *Unregulated Energy*. The unregulated energy segment includes natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and services.
- *Other*. The other segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

The following table shows the size of each of our operating segments based on operating income for 2011 and net property, plant and equipment as of December 31, 2011:

(in thousands)	**Operating Income**		**Net Property, Plant & Equipment**	
Regulated Energy	$ 44,204	83%	$ 436,438	90%
Unregulated Energy	9,326	17%	35,508	7%
Other	175	0%	15,758	3%
Total	$ 53,705	100%	$ 487,704	100%

Additional financial information by business segment is included in Item 8 under the heading Notes to the Consolidated Financial Statements Note C, Segment Information.

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(i) Regulated Energy

Overview of Business

Our regulated energy segment provides natural gas distribution service in Delaware, Maryland and Florida, electric distribution service in Florida and natural gas transmission service in Delaware, Maryland, Pennsylvania and Florida.

Natural Gas Distribution

Natural gas supplies nearly one-fourth of the energy used in the United States. Due to its efficiency, cleanliness and reliability, natural gas is growing increasingly popular. With 99 percent of the natural gas consumed in the United States coming from North America, supplies of natural gas are abundant. Natural gas is delivered to customers through a safe and efficient underground pipeline system. As the cleanest-burning fossil fuel, increased use of natural gas can help address various environmental concerns today.

Our Delaware and Maryland natural gas distribution divisions serve 53,851 residential and commercial customers and 97 industrial customers in central and southern Delaware and on Maryland s eastern shore. For the year ended December 31, 2011, operating revenues and deliveries by customer class for our Delaware and Maryland distribution divisions were as follows:

	Operating Revenues (in thousands)		Deliveries (in Dts)	
Residential	$ 46,688	62%	2,970,589	32%
Commercial	24,318	33%	3,150,272	33%
Industrial	5,044	7%	3,206,004	34%
Subtotal	76,050	102%	9,326,865	99%
Interruptible	175	0%	106,772	1%
Other [1]	(1,361)	-2%		
Total	$ 74,864	100%	9,433,637	100%

[1] Operating revenues from other include unbilled revenue, rental of gas properties, and other miscellaneous charges.

Our Florida natural gas distribution operation consists of Chesapeake s Florida division and FPU s natural gas operation, which was acquired in the merger with FPU in October 2009. In August 2010, FPU added a new division through the purchase of the natural gas operating assets of Indiantown Gas Company (IGC). On a combined basis, our Florida natural gas distribution operation serves 61,525 residential customers and 6,461 commercial and industrial customers in 20 counties in Florida. For the year ended December 31, 2011, operating revenues and deliveries by customer class for our Florida natural gas distribution operation were as follows:

	Operating Revenues (in thousands)		Deliveries (in Dts)	
Residential	$ 22,511	30%	1,503,135	7%
Commercial	35,438	46%	4,239,328	19%
Industrial	14,052	18%	17,073,057	75%
Other [1]	4,361	6%	(170,316)	-1%
Total	$ 76,362	100%	22,645,204	100%

(1) Operating revenues from "other" include unbilled revenue, conservation revenue, fees for billing services provided to third parties, other miscellaneous charges and adjustments for pass-through taxes.

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Electric Distribution

Our Florida electric distribution operation, which was acquired in the FPU merger, distributes electricity to 30,986 customers in four counties in northeast and northwest Florida. For the year ended December 31, 2011, operating revenues and deliveries by customer class for the FPU electric distribution operation were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(in MWHs)*	
Residential	$ 45,945	52%	318,065	46%
Commercial	41,525	47%	326,704	47%
Industrial	7,414	8%	52,440	7%
Subtotal	94,884	107%	697,209	100%
Other [(1)]	(5,813)	-7%	(2,556)	0%
Total	$ 89,071	100%	694,653	100%

(1) Operating revenues from other include unbilled revenue, conservation revenue, other miscellaneous charges and adjustments for pass-through taxes.

Natural Gas Transmission

Eastern Shore operates a 402-mile interstate pipeline system that transports natural gas from various points in Pennsylvania to our Delaware and Maryland natural gas distribution divisions, as well as to other utilities and industrial customers in southern Pennsylvania, Delaware and on the eastern shore of Maryland. Eastern Shore also provides swing transportation service and contract storage services. For the year ended December 31, 2011, operating revenues and deliveries by customer class for Eastern Shore were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(in Dts)*	
Local distribution companies	$ 22,363	73%	8,840,109	35%
Industrial	6,793	22%	14,056,267	55%
Commercial	2,649	9%	2,517,806	10%
Other [(1)]	(1,191)	-4%		
Subtotal	30,614	100%	25,414,182	100%
Less: affiliated local distribution companies	(14,945)	-49%	(5,555,586)	-22%
Total non-affiliated	$ 15,669	51%	19,858,596	78%

(1) Operating revenues from other sources are from rental of gas properties and reserve for rate case refund.

Peninsula Pipeline currently provides natural gas transportation service to a customer for a period of 20 years. This service, which began in January 2009, is provided at a fixed monthly charge, through Peninsula Pipeline s eight-mile pipeline located in Suwanee County, Florida. For the year ended December 31, 2011, Peninsula Pipeline generated $264,000 in operating revenues under the contract. As further discussed in Item 8 under the heading Notes to the Consolidated Financial Statements Note O, Rates and Regulatory Activities, Peninsula Pipeline has executed an agreement with the Peoples Gas System division of Tampa Electric Company (Peoples Gas) for the joint construction, ownership and operation of a 16-mile pipeline from the Duval/Nassau county line to Amelia Island in Nassau County, Florida. This jointly owned pipeline will facilitate our effort to extend natural gas service to Nassau County.

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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.

Natural Gas Distribution- Delaware and Maryland

Our Delaware and Maryland natural gas distribution divisions have both firm and interruptible transportation service contracts with five interstate open access pipeline companies, including the Eastern Shore pipeline. These divisions are directly interconnected with the Eastern Shore pipeline, and have contracts with interstate pipelines upstream of Eastern Shore, including Transcontinental Gas Pipe Line Company LLC (Transco), Columbia Gas Transmission LLC (Columbia), Columbia Gulf Transmission Company (Gulf) and Texas Eastern Transmission, LP (TETLP). The Transco, Columbia and TETLP pipelines are directly interconnected with the Eastern Shore pipeline. The Gulf pipeline is directly interconnected with the Columbia pipeline and indirectly interconnected with the Eastern Shore pipeline. None of the upstream pipelines is owned or operated by an affiliate of the Company.

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP in conjunction with TETLP s new expansion project. Upon satisfaction of certain conditions provided in the Precedent Agreement, the Delaware and Maryland divisions will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 34,100 dekatherms per day (Dts/d) and 15,900 Dts/d, respectively. The 34,000 Dts/d for our Delaware division and the 15,900 Dts/d for our Maryland division reflect the additional volume subscribed to by our divisions above the volume originally agreed to by the parties. These contracts will be effective on the service commencement date of the project, which is currently projected to occur in November 2012. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide us with an additional direct interconnection with Eastern Shore s transmission system and access to new sources of supply from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth. In December 2010, Eastern Shore completed its mainline extension to interconnect with the TETLP pipeline. Until TETLP s expansion project is completed, our Delaware and Maryland divisions expect to utilize currently available capacity on a portion of TETLP s existing pipeline. For the 2011-2012 winter heating season, our Delaware and Maryland divisions have contracted for 26,250 Dts/d and 8,750 Dts/d, respectively, from TETLP.

The Delaware and Maryland divisions use their firm transportation resources to meet a significant percentage of their projected demand requirements, and they purchase firm natural gas supplies on the spot market from various suppliers as needed to match firm supply and demand. This gas is transported by the upstream pipelines and delivered to their interconnections with Eastern Shore. The Delaware and Maryland divisions also have the capability to use propane-air peak-shaving equipment to supplement or displace natural gas purchases.

The following table shows the firm transportation and storage capacity for peak-day deliverability that the Delaware and Maryland divisions currently have under contract with Eastern Shore and pipelines upstream of the Eastern Shore pipeline, including the respective contract expiration dates.

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Delaware

Pipeline	**Firm transportation capacity maximum peak-day daily deliverability** *(in Dts)*	**Firm storage capacity maximum peak-day daily withdrawal** *(in Dts)*	**Expiration**
Transco	21,423	6,230	Various dates between 2012 and 2028
Columbia	10,960	8,224	Various dates between 2014 and 2020
Gulf	880		Expires in 2014
TETLP	26,250		Expires in 2012
Eastern Shore	68,613	4,146	Various dates between 2012 and 2027

Maryland

Pipeline	**Firm transportation capacity maximum peak-day daily deliverability** *(in Dts)*	**Firm storage capacity maximum peak-day daily withdrawal** *(in Dts)*	**Expiration**
Transco	6,128	2,970	Various dates between 2012 and 2015
Columbia	4,200	3,663	Various dates between 2014 and 2019
Gulf	590		Expires in 2014
TETLP	8,750		Expires in 2012
Eastern Shore	22,878	2,307	Various dates between 2013 and 2027

Natural Gas Distribution Florida

Chesapeake s Florida natural gas distribution division has firm transportation service contracts with Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System, LLC (Gulfstream). Pursuant to a program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties and PESCO, our natural gas marketing subsidiary. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

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Contracts by Chesapeake s Florida natural gas distribution division with FGT include two contracts, which expire on July 31, 2012 and 2015, and one contract with Gulfstream, which expires in 2022. These contracts are summarized in the following table:

Pipeline	Month(s)	Daily Firm Transportation Capacity *(in Dts)*	Expiration
FGT	November to April	17,639	July 31, 2012
FGT	May to September	15,092	July 31, 2012
FGT	October	16,579	July 31, 2012
FGT	January to December	1,000	2015
Gulfstream	January to December	10,000	2022

FPU has two firm transportation contracts with FGT, which expire in February 2015 and July 2020, and a third contract with various expiration dates between 2016 and 2023. FPU s firm transportation contract with Florida City Gas expires in 2013. These contracts are summarized in the following table:

Pipeline	Month(s)	Daily Firm Transportation Capacity *(in Dts)*	Expiration
FGT	January to March	29,421	July 2020
FGT	April	24,808	July 2020
FGT	May to September	9,943	July 2020
FGT	October	10,485	July 2020
FGT	November to December	29,421	July 2020
FGT	January to April	10,564	February 2015
FGT	May to October	4,478	February 2015
FGT	November to December	10,564	February 2015
FGT	January to December	1,822	Various dates between 2016 and 2023
Florida City Gas	January to December	300	2013

FPU uses gas marketers and producers to procure all of its gas supplies for its natural gas distribution operation. FPU also uses Peoples Gas to provide wholesale gas sales service in areas distant from its interconnections with FGT.

Natural Gas Transmission

Eastern Shore has three contracts with Transco for a total of 7,292 dekatherms (Dts) of firm peak day storage entitlements and total storage capacity of 288,003 Dts. One of the contracts expires in 2013 and the other two contracts expire in 2023. Eastern Shore has retained these firm storage services in order to provide swing transportation service and firm storage service to those customers that have requested such services.

Electric Distribution

Our electric distribution operation through FPU purchases all of its wholesale electricity from two suppliers: Gulf Power Company (Gulf Power) and JEA (formerly known as Jacksonville Electric Authority). Both of these contracts are all requirements contracts, and they expire in December 2019 and December 2017, respectively. The JEA contract provides generation, transmission and distribution service to northeast Florida. The Gulf Power contract provides generation, transmission and distribution service to northwest Florida.

Competition

See discussion of competition in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Competition.

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Rates and Regulation

Our natural gas and electric distribution operations are subject to regulation by the Delaware, Maryland or Florida PSCs with respect to various aspects of their business, including rates for sales and transportation to all customers in each respective regulatory jurisdiction. All of our firm distribution sales rates are subject to fuel cost recovery mechanisms, which match revenues with natural gas and electric supply and transportation costs and normally allow full recovery of such costs. Adjustments under these mechanisms, which are limited to such costs, require periodic filings and hearings with the state PSC having jurisdiction.

Eastern Shore is subject to regulation as an interstate pipeline by the FERC, which regulates the terms and conditions of service and the rates Eastern Shore can charge for its transportation and storage services. Peninsula Pipeline is subject to regulation by the Florida PSC.

The following table shows the regulatory jurisdictions under which our regulated energy businesses currently operate, including the effective dates of the most recent full rate proceedings and the rates of return that were authorized therein:

Regulated Business	Regulatory Jurisdiction	Effective Date of the Currrent Rates	Allowed Return
Chesapeake - Delaware Division	Delaware PSC	9/3/2008	10.25% (1)
Chesapeake - Maryland Division	Maryland PSC	12/1/2007	10.75% (1)
Chesapeake - Florida Division	Florida PSC	1/14/2010	10.80% (1)
FPU - Natural Gas	Florida PSC	1/14/2010 (3)	10.85% (1)
FPU - Indiantown Division	Florida PSC	6/17/2004	11.50% (1)
FPU - Electric	Florida PSC	5/22/2008	11.00% (1)
Eastern Shore	FERC	7/29/2011	13.90% (2)

(1) Allowed return on equity
(2) Allowed overall pre-tax, pre-interest rate of return
(3) Effective date of the Order approving settlement agreement, which adjusted rates originally approved on June 4, 2009.

Peninsula Pipeline, which is regulated by the Florida PSC, currently provides service to one customer at a negotiated rate.

Management monitors the achieved rates of return of each of our regulated energy operations in order to ensure timely filing of rate cases.

Regulatory Proceedings

See discussion of regulatory activities in Item 8 under the heading Notes to the Consolidated Financial Statements Note O, Rates and Other Regulatory Activities.

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Seasonality of Natural Gas and Electric Distribution Revenues

Revenues from our residential and commercial natural gas distribution activities 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. Sustained warmer-than-normal temperatures during the heating season will tend to reduce use of natural gas and electricity, while sustained colder-than-normal temperatures will tend to increase consumption. Sustained cooler-than-normal temperatures during the cooling season will negatively affect electricity consumption. 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 (HDD). Each degree of temperature above 65 degree Fahrenheit is counted as one cooling degree-day (CDD). Normal heating degree-days are based on the most recent 10-year average.

For the electric distribution operations in northeast and northwest Florida, hot summers and cold winters produce year-round electric sales that normally do not have large seasonal fluctuations.

In an effort to stabilize the level of net revenues collected from customers regardless of weather conditions, we received approval from the Maryland PSC on September 26, 2006 to implement 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.

Delaware, like many other states, has been looking at ways to enable implementation of energy efficiency and is considering revenue decoupling, which is a mechanism for separating the revenue needed to recover the fixed cost of delivery from the variable cost that fluctuates with the amount of natural gas consumed. Since March of 2007, the Delaware PSC has been investigating whether to implement a revenue decoupling mechanism for the natural gas distribution utilities that it regulates. Recently in response to a decoupling request by another Delaware distribution utility, the Delaware PSC decided that it would need a further review of the proposed implementation plan, including more customer education about decoupling and a greater awareness of energy efficiency programs, prior to approving the request. In light of the Delaware PSC s recent actions, it is uncertain as to whether our Delaware natural gas distribution division will file or be required to file a request for decoupling.

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(ii) Unregulated Energy

Overview of Business

Our unregulated energy segment provides natural gas marketing, propane distribution and propane wholesale marketing services to customers.

Natural Gas Marketing

Our natural gas marketing subsidiary, PESCO, provides natural gas supply and supply management services to 3,080 customers in Florida and 16 customers on the Delmarva Peninsula. It 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 through the billing services of the regulated utilities that deliver the gas, or directly, through its own billing capabilities. For the year ended December 31, 2011, PESCO s operating revenues and deliveries were as follows:

Service Area	Operating Revenues (in thousands)		Deliveries (in Dts)	
Florida	$ 46,249	87%	11,324,032	90%
Delmarva	7,037	13%	1,236,079	10%
Total	$ 53,286	100%	12,560,111	100%

PESCO currently has contracts with natural gas production companies for the purchase of firm natural gas supplies. These contracts provide a maximum firm daily entitlement of 35,000 Dts and expire in May 2012. PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements prior to the end of the term of the existing contracts.

Propane Distribution

Propane is a form of liquefied petroleum gas, which is typically extracted from natural gas or separated during the crude oil refining process. Although propane is a gas at normal pressure, it is easily compressed into liquid form for storage and transportation. Propane is a clean-burning fuel, gaining increased recognition for its environmental superiority, safety, efficiency, transportability and ease of use relative to alternative forms of fossil fuels. Propane is sold primarily in suburban and rural areas which are not served by natural gas distributors.

Sharp, our propane distribution subsidiary, serves 34,317 customers throughout Delaware, the eastern shore of Maryland and Virginia, and southeastern Pennsylvania. Our Florida propane distribution subsidiary provides propane distribution service to 14,507 customers in parts of Florida. For the year ended December 31, 2011, operating revenues and total gallons sold by our Delmarva and Florida propane distribution operations were as follows:

Service Area	Operating Revenues (in thousands)		Total Gallons Sold (in thousands)	
Delmarva	$ 72,441	78%	31,003	83%
Florida	20,149	22%	6,404	17%
Total	$ 92,590	100%	37,407	100%

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Propane Wholesale Marketing

Xeron, our propane wholesale marketing subsidiary, markets propane to large, independent petrochemical companies, resellers and retail propane companies in the southeastern United States. The propane wholesale marketing business is affected by both propane wholesale price volatility and supply levels. In 2011, Xeron had operating revenues totaling approximately $2.3 million, net of the associated cost of propane sold. For further discussion of Xeron s wholesale marketing activities, market risks and controls that monitor Xeron s risks, see Item 7 under the heading 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.

Supplies, Transportation and Storage

Our propane distribution operations purchase propane primarily from suppliers, including major oil companies, independent producers of natural gas liquids and from Xeron. In current markets, supplies of propane from these and other sources are readily available for purchase.

Our propane distribution operations use trucks and railroad cars to transport propane from refineries, natural gas processing plants or pipeline terminals to our bulk storage facilities. We own bulk propane storage facilities with an aggregate capacity of approximately 3.4 million gallons at various locations 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.

Competition

See discussion of competition in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Competition.

Rates and Regulation

Natural gas marketing, propane distribution and propane wholesale marketing activities are not subject to any federal or state pricing regulation. Transport operations are subject to regulations concerning the transportation of hazardous materials promulgated by the Federal Motor Carrier Safety Administration within the United States Department of Transportation and enforced by the various states in which such operations take place. Propane distribution operations are also subject to state safety regulations relating to hook-up and placement of propane tanks.

Seasonality of Propane Revenues

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, customers demand substantially increases during the winter months when propane is used for heating. Accordingly, the propane volumes sold for this purpose 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.

(iii) Other

The other segment consists primarily of our advanced information services subsidiary, other unregulated subsidiaries that own real estate leased to Chesapeake and its subsidiaries and certain unallocated corporate costs. Certain corporate costs that have not been allocated to different operations consist of merger-related costs that have been expensed and have not been allocated because such costs are not directly attributable to the business unit operations.

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Advanced Information Services

Our advanced information services subsidiary, BravePoint, is headquartered in Norcross, Georgia, and provides domestic and a limited number of international clients with information technology services and solutions for both enterprise and e-business applications.

Other Subsidiaries

Skipjack, Inc. and Eastern Shore Real Estate, Inc. own and lease office buildings in Delaware and Maryland to affiliates of Chesapeake. Chesapeake Investment Company is an affiliated investment company incorporated in Delaware.

(c) Additional Information about the Business

(i) Capital Budget

A discussion of capital expenditures by business segment and capital expenditures for environmental remediation facilities is included in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

(ii) Employees

As of December 31, 2011, we had a total of 711 employees, 130 of whom are union employees represented by three labor unions: the International Brotherhood of Electrical Workers, the International Chemical Workers Union and United Food and Commercial Workers Union, all of whose collective bargaining agreements expire in 2013.

(iii) Financial Information about Geographic Areas

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

(d) Available Information

As a public company, we file annual, quarterly and other reports, as well as our annual proxy statement and other information, with the Securities and Exchange Commission (SEC). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 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.

The SEC also maintains an Internet site that contains reports, proxy and information statements and other information regarding the Company. The address of the SEC s Internet website is *www.sec.gov*. We make available, free of charge, on our Internet website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after such reports are electronically filed with or furnished to the SEC. The address of our Internet website is *www.chpk.com*. The content of this website is not part of this report.

We have a Business Code of Ethics and Conduct applicable to all employees, officers and directors and a Code of Ethics for Financial Officers. Copies of the Business Code of Ethics and Conduct and the Financial Officer Code of Ethics are available on our Internet website. We also adopted Corporate Governance Guidelines and Charters for the Audit Committee, Compensation Committee and Corporate Governance Committee of the Board of Directors, each of which satisfies the regulatory requirements established by the SEC and the New York Stock Exchange (NYSE). The Board of Directors has also adopted Corporate Governance Guidelines on Director Independence, which conform to the NYSE listing standards on director independence. These documents are available on our Internet website or may be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, DE 19904.

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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.

Our Chief Executive Officer certified to the NYSE on June 2, 2011, that as of that date, he was unaware of any violation by Chesapeake of the NYSE s corporate governance listing standards.

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 Management s Discussion and Analysis of Financial Condition and Results of Operations under Item 7 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 have a negative impact on our growth strategy.

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. Specifically, 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. Currently, $40 million of the total $100 million of short-term lines of credit utilized to satisfy our short-term financing requirements are discretionary, uncommitted lines of credit. We utilize discretionary lines of credit to reduce the cost associated with these short-term financing requirements. We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access the 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.

Our financial condition would be adversely affected if we fail to comply with our debt covenant obligations.

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 would 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 would negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories, as well as to temporarily finance capital expenditures.

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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. 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.

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

Our natural gas marketing and propane wholesale marketing operations are subject to market risks beyond their 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 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 its customers in relation to its 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 timing of the recognition of profits or losses on the economic hedges for financial accounting purposes usually does not match up with the timing of the economic profits or losses on the item being hedged. 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, which could adversely affect our results of operations, cash flows and financial condition.

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 subject to credit requirements that may adversely affect our results of operations, cash flows and financial condition.

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.

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Current market conditions have adversely impacted the return on plan assets for our pension plans, which may require significant additional funding and adversely affect our cash flows and results of operations.

We have pension plans that have been closed to new employees. 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 on 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 adversely affect our results of operations, cash flows and financial condition.

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 of natural gas and propane 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 operations, while generally less seasonal than natural gas and propane sales as electricity is used for both heating and cooling in our service areas, are also affected by variations in general weather conditions and particularly unusually severe weather conditions.

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, closings of generation facilities and refineries. 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 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 materially 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.

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A substantial disruption or lack of growth in interstate natural gas pipelines transmission and storage capacity and 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 on one pipeline system, FGT, for most of its natural gas supply and transmission. Our Florida electric operation relies 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 changes may 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/Electric. 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 can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, decreasing 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. Our net income, however, 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 and consequently have an adverse effect on our operating cash flows.

Propane. Propane costs are subject to volatile changes as a result of product supply or other market conditions, including weather and 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 risk, which may adversely affect our results of operations and financial condition.

Our propane distribution operations own bulk propane storage facilities, with an aggregate capacity of approximately 3.4 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 price of the propane that we purchase 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 accounting principles generally accepted in the United States of America (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 systems could adversely affect the results of operations, cash flows and financial condition.

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

Our electric operation is subject to various operational risks, including accidents, outages, equipment breakdowns or failures, or operations below expected levels of performance or efficiency. Problems such as the breakdown or failure of electric equipment or processes and interruptions in service, which would result in performance below expected levels of output or efficiency, particularly if extended for prolonged periods of time, could have a materially adverse effect on our financial condition and results of operations.

Because we operate in a competitive environment, we may lose customers to competitors, which could adversely affect our results of operations, cash flows and financial condition.

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 customer base in the natural gas operations 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 new service territories, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane gas operations would have an adverse effect on our results of operations, cash flows and financial condition.

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

Changes in technology may adversely affect our advanced information services subsidiary s results of operations, cash flows and financial condition.

BravePoint participates in a market that is characterized by rapidly changing technology and accelerating product introduction cycles. The success of our advanced information services subsidiary depends upon our ability to address the rapidly changing needs of our customers by developing and supplying high-quality, cost-effective products, product enhancements and services, on a timely basis, and by keeping pace with technological developments and emerging industry standards. There is no assurance that we will be able to keep up with technological advancements to the degree necessary to keep our products and services competitive.

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 and puts, to hedge price risk. In addition, we have utilized in the past, and may decide, after further evaluation, to continue to utilize derivative instruments 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.

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Changes in customer growth may 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 these markets may adversely affect our gross margin in our regulated energy or propane distribution businesses, earnings and cash flows.

Our businesses are capital intensive, and the costs of capital projects may be significant.

Our businesses are capital intensive and require significant investments in internal infrastructure projects. Our results of operations and financial condition could be adversely affected if we do not pursue or 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 results of operation.

We are party to collective bargaining agreements with various 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.

The risk of terrorism and political unrest and the current hostilities in the Middle East may adversely affect the economy and the price and availability of propane, refined fuels, electricity and natural gas.

Terrorist attacks, political unrest and the current hostilities in the Middle East may adversely affect the price and availability of propane, refined fuels, electricity and natural gas, as well as our results of operations, our ability to raise capital and our future growth. The impact that the foregoing may have on our industry in general, and on us in particular, is not known at this time. An act of terror could result in disruptions of crude oil, electricity or natural gas supplies and markets, and our infrastructure facilities could be direct or indirect targets. Terrorist activity may also hinder our ability to transport or transmit propane, electricity and natural gas if our means of supply transportation, such as rail, power grid or pipeline, become damaged as a result of an attack. A lower level of economic activity following such events could result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of terrorism could also affect our ability to raise capital. Terrorist activity and hostilities in the Middle East could likely lead to increased volatility in prices for propane, refined fuels, electricity and natural gas. We maintain insurance policies with insurers in such amounts and with such coverage and deductibles as we believe are reasonable and prudent. There can be no assurance, however, 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.

Operational interruptions to our natural gas transmission and natural gas and electric distribution activities, caused by accidents, malfunctions, severe weather (such as a major hurricane), or acts of terrorism, could adversely impact earnings.

Inherent in natural gas transmission and natural gas and electric distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions, severe weather, major storms and mechanical problems. If they are severe enough or if they lead to operational interruptions, they could cause substantial financial losses. In addition, these risks could result in the loss of human life, significant damage to property, environmental damage and impairment of our operations. The location of pipeline, storage, transmission and distribution facilities near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering places, could increase the level of damages resulting from these risks. Our natural gas and electric distribution, natural gas transmission and propane storage facilities may suffer damage as a result of severe weather or a major storm or other casualty, and may be targets of terrorist activities that could disrupt our ability to meet customer requirements. Damage to our facilities, or those of our suppliers or customers, could result in a significant decrease in revenues or a significant increase in repair costs. The occurrence of any of these events could adversely affect our results of operations, cash flows and financial condition.

Regulatory and Legal 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 PSCs or the FERC in the case of Eastern Shore may require us to reduce our rates charged to customers in the future.

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: (a) our ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on terms that are acceptable to us; (b) 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; (c) inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (d) lack of anticipated future growth in available natural gas and electricity supply; and (e) 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 policies with insurers to cover our general liabilities in the amount of $51 million, which we believe are reasonable and prudent. There can be no assurance, however, 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.

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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 increased investment in 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 resulting from such proposals. If such legislation is adopted and we incur additional expenses and expenditures as a result, our financial conditions, 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.

Environmental Risks

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 manufactured gas plant (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. There is no guarantee, however, 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.

Pending environmental matters, particularly with respect to FPU s site in West Palm Beach, Florida, may have a materially adverse effect on our Company and our results of operations.

We have participated in the investigation, assessment or remediation of environmental matters with respect to certain of our properties and we believe we have exposures at six former MGP sites located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the Maryland Department of the Environment (MDE) regarding a seventh former MGP site located in Cambridge, Maryland.

The site with the most potential exposure is the former West Palm Beach MGP. In November 2010, we presented a new proposed strategy with an aggressive remedial action plan to expedite remediation of this site, and the Florida Department of Environmental Protection (FDEP) agreed with the proposal to implement a phased approach. In February 2011, FDEP approved the interim Remedial Action Plan (RAP) for the east parcel of this site, contingent upon certain conditions. Subsequent modifications to the interim RAP, dated March 12, 2011 and April 18, 2011, were submitted to address potential concerns raised by FDEP. An Approval Order for the interim RAP was issued by FDEP on May 2, 2011, and subsequently modified by FDEP on May 18, 2011. FPU is currently implementing the interim RAP. Our current estimate of total remediation costs and expenses for the West Palm Beach site based on the most recently proposed RAP is between \$4.7 million and \$15.8 million. This estimate includes costs associated with relocation of our operations from the site, which may be necessary to implement the remedial action, and any potential costs associated with re-development of the property. Actual costs may also be higher or lower than the range of current estimates based upon the final remedy required by FDEP.

As of December 31, 2011, we had recorded $254,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Winter Haven, Florida, representing our estimate of the future costs associated with those sites. We had recorded approximately $991,000 in assets for future recovery of environmental costs to be received from our customers through our approved rates. As of December 31, 2011, we had recorded approximately $11.0 million in environmental liabilities related to FPU s MGP sites in Florida, which includes the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates. Approximately $8.3 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of December 31, 2011. We also had approximately $5.7 million in regulatory assets for future recovery of environmental costs from FPU s customers.

The costs and expenses we incur to address environmental issues at our sites may have a material adverse effect on our results of operations and earnings to the extent that such costs and expenses exceed the amounts we have accrued as environmental reserves or that we are otherwise permitted to recover from customers through rates. At present, we believe that the amounts accrued as environmental reserves and that we are otherwise permitted to recover from customers through rates are sufficient to fund the pending environmental liabilities previously described.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

(a) General

We own offices and operate facilities in the following locations: Pocomoke, Salisbury, Cambridge and Princess Anne, Maryland; Dover, Seaford, Laurel and Georgetown, Delaware; Lecato, Virginia; and West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill, Fernandina Beach and Winter Haven, Florida. We rent office space in Dover, Ocean View, and South Bethany, Delaware; West Palm Beach, Fernandina Beach and Lecanto, Florida; Chincoteague and Belle Haven, Virginia; Easton, Maryland; Honey Brook and Allentown, Pennsylvania; Houston, Texas; and Norcross, Georgia. In general, we believe that our offices and facilities are adequate for the uses for which they are employed.

(b) Natural Gas Distribution

Our Delmarva natural gas distribution operation owns approximately 1,181 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in our Delaware and Maryland service areas. Our Florida natural gas distribution operation owns 2,481 miles of natural gas distribution mains (and related equipment). In addition, we have adequate gate stations to handle receipt of the gas in 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.

(c) Natural Gas Transmission

Eastern Shore owns and operates approximately 402 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Daleville and Honey Brook, Pennsylvania; and Hockessin, Delaware, to approximately 85 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland.

Peninsula Pipeline owns and operates approximately eight miles of transmission pipeline in Suwanee County, Florida.

(d) Electric Distribution

Our electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 895 miles of electric distribution line located in northeast and northwest Florida.

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(e) Propane Distribution and Wholesale Marketing

Our Delmarva-based propane distribution operation owns bulk propane storage facilities, with an aggregate capacity of approximately 2.7 million gallons, at 32 plant facilities in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by our Company. Our Florida-based propane distribution operation owns 31 bulk propane storage facilities with a total capacity of 690,000 gallons. 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.

(f) Lien

All of the properties owned by FPU are subject to a lien in favor of the holders of its first mortgage bonds securing its indebtedness under its Mortgage Indenture and Deed of Trust. FPU owns offices and operates facilities in the following locations: West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill and Fernandina Beach, Florida. FPU s natural gas distribution operation owns 1,681 miles of natural gas distribution mains (and related equipment) in its service areas. FPU s electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 895 miles of electric distribution line located in northeast and northwest Florida. FPU s propane distribution operation owns 31 bulk propane storage facilities with a total capacity of 690,000 gallons located in south and central Florida.

ITEM 3. LEGAL PROCEEDINGS.

(a) General

As disclosed in Item 8 under the heading Notes to the Consolidated Financial Statements Note Q, Other Commitments and Contingencies, 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.

(b) Environmental

See discussion of environmental commitments and contingencies in Item 8 under the heading Notes to the Consolidated Financial Statements Note P, Environmental Commitments and Contingencies.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

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ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT.

Set forth below are the names, ages, and positions of executive officers of the registrant 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	53	President and Chief Executive Officer
Beth W. Cooper	45	Senior Vice President and Chief Financial Officer
Stephen C. Thompson	51	Senior Vice President and President, Eastern Shore
Elaine B. Bittner	42	Vice President of Strategic Development

Michael P. McMasters is President and Chief Executive Officer of Chesapeake. Mr. McMasters assumed the role of Chief Executive Officer effective January 1, 2011 and was appointed as President on March 1, 2010. Prior to these appointments, Mr. McMasters served as Chief Operating Officer since 2008, Senior Vice President since 2004 and Chief Financial Officer of Chesapeake since 1996. He has previously held the positions of Vice President, Treasurer, Director of Accounting and Rates, and Controller. From 1992 to May 1994, Mr. McMasters was employed as Director of Operations Planning for Equitable Gas Company.

Beth W. Cooper was appointed as Senior Vice President and Chief Financial Officer in September 2008 in addition to her duties as Treasurer and Corporate Secretary. Prior to this appointment, Ms. Cooper served as Vice President and Corporate Secretary since July 2005. She has served as Treasurer since 2003. She previously served as Assistant Treasurer and Assistant Secretary, Director of Internal Audit, Director of Strategic Planning, Planning Consultant, Accounting Manager for Non-regulated Operations and Treasury Analyst. Prior to joining Chesapeake, she was employed as an auditor with Ernst & Young s Entrepreneurial Services Group.

Stephen C. Thompson is Senior Vice President of Chesapeake and President of Eastern Shore. Prior to becoming Senior Vice President in 2004, he served as Vice President of Chesapeake. He has also served as Vice President, Director of Gas Supply and Marketing, Superintendent of Eastern Shore and Regional Manager for the Florida distribution operations.

Elaine B. Bittner was appointed as Vice President of Strategic Development in June 2010. Prior to this appointment, Ms. Bittner served as Vice President of Eastern Shore since 2005. She previously served as Director of Eastern Shore, Director of Customer Services and Regulatory Affairs for Eastern Shore, Director of Environmental Affairs for Chesapeake, Manager of Environmental Affairs and Environmental Engineer. Prior to joining Chesapeake, Ms. Bittner was a Project Chemist, Client Consultant and Environmental Lab Chemist in the environmental industry specializing in environmental analysis and reporting related to volatile organic compounds.

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PART II

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

(a) Common Stock Price Ranges, Common Stock Dividends and Shareholder Information:

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 2011 and 2010 were as follows:

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2011					
	March 31	**$ 42.47**	**$ 37.67**	**$ 41.62**	**$ 0.330**
	June 30	**$ 43.14**	**$ 37.66**	**$ 40.03**	**$ 0.345**
	September 30	**$ 41.50**	**$ 36.00**	**$ 40.11**	**$ 0.345**
	December 31	**$ 44.53**	**$ 38.30**	**$ 43.35**	**$ 0.345**
2010					
	March 31	$ 32.25	$ 28.22	$ 29.80	$ 0.315
	June 30	$ 32.20	$ 28.01	$ 31.40	$ 0.330
	September 30	$ 36.93	$ 30.24	$ 36.22	$ 0.330
	December 31	$ 42.20	$ 35.00	$ 41.52	$ 0.330

Holders

At February 29, 2012, there were 2,461 holders of record of Chesapeake common stock.

Dividends

We have paid a cash dividend to common stock shareholders for 51 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 2011 and 2010, totaling $1.365 per share and $1.305 per share, respectively.

Indentures to our long-term debt contain various restrictions. In terms of restrictions which limit the payment of dividends by Chesapeake, each of its unsecured senior notes contains a Restricted Payments covenant. The most restrictive covenants of this type are included within the 7.83 percent Senior Notes, due January 1, 2015. The covenant provides that Chesapeake 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, 2001. As of December 31, 2011, Chesapeake s cumulative consolidated net income base was $156.5 million, offset by Restricted Payments of $89.2 million, leaving $67.3 million of cumulative net income free of restrictions.

Each series of FPU s first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which provides 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, 2011, FPU had a cumulative net income base of $74.0 million, offset by restricted payments of $37.6 million, leaving $36.4 million of cumulative net income of FPU free of restrictions based on this covenant.

Recent Sales of Unregistered Securities

No securities were sold during the year 2011 that were not registered under the Securities Act of 1933, as amended.

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(b) 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, 2011.

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, 2011 through October 31, 2011 [(1)]	261	$ 40.08		
November 1, 2011 through November 30, 2011				
December 1, 2011 through December 31, 2011				
Total	261	$ 40.08		

(1) Chesapeake purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading Notes to the Consolidated Financial Statements Note N, Share-based Compensation Plans. During the quarter, 261 shares were purchased through the reinvestment of dividends on deferred stock units.

(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, 2012, in connection with our Annual Meeting to be held on or about May 2, 2012, and is incorporated herein by reference.

(c) Chesapeake Utilities Corporation Common Stock Performance Graph

The following Stock Performance graph compares cumulative total stockholder return on a hypothetical investment in our common stock during the five fiscal years ended December 31, 2011, with the cumulative total stockholder return on a hypothetical investment in both (i) the Standard & Poor s 500 Index (S&P 500 Index), and (ii) an industry index consisting of Chesapeake and 10 other companies from the current Edward Jones Natural Gas Distribution Group, a published listing of selected gas distribution utilities results. The Compensation Committee compares the performance of the companies from the Edward Jones Natural Gas Distribution Group to our performance for purposes of determining the level of long-term performance awards earned by our named executive officers.

The 10 other companies from the current Edward Jones Natural Gas Distribution Group are: 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, 2006 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.

	2006	2007	2008	2009	2010	2011
Chesapeake	$ 100	$ 108	$ 111	$ 117	$ 156	$ 168
Industry Index	$ 100	$ 103	$ 111	$ 114	$ 134	$ 155
S&P 500 Index	$ 100	$ 105	$ 67	$ 84	$ 97	$ 99

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ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2011	2010	2009 [2]
Operating [1]			
(in thousands)			
Revenues			
Regulated Energy	**$ 256,773**	$ 269,934	$ 139,099
Unregulated Energy	**149,586**	146,793	119,973
Other	**11,668**	10,819	9,713
Total revenues	**$ 418,027**	$ 427,546	$ 268,785
Operating income			
Regulated Energy	**$ 44,204**	$ 43,509	$ 26,900
Unregulated Energy	**9,326**	7,908	8,158
Other	**175**	513	(1,322)
Total operating income	**$ 53,705**	$ 51,930	$ 33,736
Net income from continuing operations	**$ 27,622**	$ 26,056	$ 15,897
Assets			
(in thousands)			
Gross property, plant and equipment	**$ 625,488**	$ 584,385	$ 543,905
Net property, plant and equipment	**$ 487,704**	$ 462,757	$ 436,587
Total assets	**$ 709,066**	$ 670,993	$ 615,811
Capital expenditures [1]	**$ 44,431**	$ 46,955	$ 26,294
Capitalization			
(in thousands)			
Stockholders equity	**$ 240,780**	$ 226,239	$ 209,781
Long-term debt, net of current maturities	**110,285**	89,642	98,814
Total capitalization	**$ 351,065**	$ 315,881	$ 308,595
Current portion of long-term debt	**8,196**	9,216	35,299
Short-term debt	**34,707**	63,958	30,023
Total capitalization and short-term financing	**$ 393,968**	$ 389,055	$ 373,917

(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 (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) FASB ASC 718, Compensation Stock Compensation, and FASB 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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2008	2007	2006 [3]	2005	2004	2003	2002
$ 116,468	$ 128,850	$ 124,631	$ 124,563	$ 98,139	$ 92,079	$ 82,098
161,290	115,190	94,320	90,995	67,607	59,197	40,728
13,685	14,246	12,249	13,927	12,209	12,292	12,430
$ 291,443	$ 258,286	$ 231,200	$ 229,485	$ 177,955	$ 163,568	$ 135,256
$ 24,733	$ 21,809	$ 18,593	$ 16,248	$ 16,258	$ 16,219	$ 14,867
3,781	5,174	3,675	4,197	3,197	4,310	1,158
(35)	1,131	1,064	1,476	722	1,050	580
$ 28,479	$ 28,114	$ 23,332	$ 21,921	$ 20,177	$ 21,579	$ 16,605
$ 13,607	$ 13,218	$ 10,748	$ 10,699	$ 9,686	$ 10,079	$ 7,535
$ 381,689	$ 352,838	$ 325,836	$ 280,345	$ 250,267	$ 234,919	$ 229,128
$ 280,671	$ 260,423	$ 240,825	$ 201,504	$ 177,053	$ 167,872	$ 166,846
$ 385,795	$ 381,557	$ 325,585	$ 295,980	$ 241,938	$ 222,058	$ 223,721
$ 30,844	$ 30,142	$ 49,154	$ 33,423	$ 17,830	$ 11,822	$ 13,836
$ 123,073	$ 119,576	$ 111,152	$ 84,757	$ 77,962	$ 72,939	$ 67,350
86,422	63,256	71,050	58,991	66,190	69,416	73,408
$ 209,495	$ 182,832	$ 182,202	$ 143,748	$ 144,152	$ 142,355	$ 140,758
6,656	7,656	7,656	4,929	2,909	3,665	3,938
33,000	45,664	27,554	35,482	5,002	3,515	10,900
$ 249,151	$ 236,152	$ 217,412	$ 184,159	$ 152,063	$ 149,535	$ 155,596

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For the Years Ended December 31,	2011	2010	2009 [2]
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [1]	**$ 2.89**	$ 2.75	$ 2.17
Diluted earnings per share from continuing operations [1]	**$ 2.87**	$ 2.73	$ 2.15
Return on average equity from continuing operations [1]	**11.6%**	11.6%	11.2%
Common equity / total capitalization	**68.6%**	71.6%	68.0%
Common equity / total capitalization and short-term financing	**61.1%**	58.2%	56.1%
Book value per share	**$ 25.15**	$ 23.75	$ 22.33
Market price:			
High	**$ 44.530**	$ 42.200	$ 35.000
Low	**$ 36.000**	$ 28.010	$ 22.020
Close	**$ 43.350**	$ 41.520	$ 32.050
Average number of shares outstanding	**9,555,799**	9,474,554	7,313,320
Shares outstanding at year-end	**9,567,307**	9,524,195	9,394,314
Registered common shareholders	**2,481**	2,482	2,670
Cash dividends declared per share	**$ 1.37**	$ 1.31	$ 1.25
Dividend yield (annualized) [4]	**3.2%**	3.2%	3.9%
Payout ratio from continuing operations [1] [5]	**47.4%**	47.6%	57.6%
Additional Data			
Customers			
Natural gas distribution	**121,934**	120,230	117,887
Electric distribution	**30,986**	30,966	31,030
Propane distribution	**48,824**	48,100	48,680
Volumes			
Natural gas deliveries (in Dts)	**57,493,022**	49,310,314	50,159,227
Electric Distribution (in MWHs)	**694,653**	751,507	105,739
Propane distribution (in thousands of gallons)	**37,387**	39,807	32,546
Heating degree-days (Delmarva Peninsula)			
Actual HDD	**4,221**	4,831	4,729
10-year average HDD (normal)	**4,499**	4,528	4,462
Propane bulk storage capacity (in thousands of gallons)	**3,351**	3,041	3,042
Total employees [1]	**711**	734	757

[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] FASB ASC 718, Compensation Stock Compensation, and FASB ASC 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.

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2008	2007	2006 (3)	2005	2004	2003	2002
$ 2.00	$ 1.96	$ 1.78	$ 1.83	$ 1.68	$ 1.80	$ 1.37
$ 1.98	$ 1.94	$ 1.76	$ 1.81	$ 1.64	$ 1.76	$ 1.37
11.2%	11.5%	11.0%	13.2%	12.8%	14.4%	11.2%
58.7%	65.4%	61.0%	59.0%	54.1%	51.2%	47.8%
49.4%	50.6%	51.1%	46.0%	51.3%	48.8%	43.3%
$ 18.03	$ 17.64	$ 16.62	$ 14.41	$ 13.49	$ 12.89	$ 12.16
$ 34.840	$ 37.250	$ 35.650	$ 35.780	$ 27.550	$ 26.700	$ 21.990
$ 21.930	$ 28.000	$ 27.900	$ 23.600	$ 20.420	$ 18.400	$ 16.500
$ 31.480	$ 31.850	$ 30.650	$ 30.800	$ 26.700	$ 26.050	$ 18.300
6,811,848	6,743,041	6,032,462	5,836,463	5,735,405	5,610,592	5,489,424
6,827,121	6,777,410	6,688,084	5,883,099	5,778,976	5,660,594	5,537,710
1,914	1,920	1,978	2,026	2,026	2,069	2,130
$ 1.21	$ 1.18	$ 1.16	$ 1.14	$ 1.12	$ 1.10	$ 1.10
3.9%	3.7%	3.8%	3.7%	4.2%	4.2%	6.0%
60.5%	60.2%	65.2%	62.3%	66.7%	61.1%	80.3%
65,201	62,884	59,132	54,786	50,878	47,649	45,133
34,981	34,143	33,282	32,117	34,888	34,894	34,566
46,539,142	42,910,964	41,826,357	43,716,921	39,469,915	37,478,009	36,160,884
27,956	29,785	24,243	26,178	24,979	25,147	21,185
4,431	4,504	3,931	4,792	4,553	4,715	4,161
4,401	4,376	4,372	4,436	4,389	4,409	4,393
2,471	2,441	2,315	2,315	2,045	2,195	2,151
448	445	437	423	426	439	455

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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 financial results of the Company and its 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.

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

(a) Introduction

Chesapeake is a diversified utility company engaged, directly or through subsidiaries, in regulated energy businesses, unregulated energy businesses, and other unregulated businesses, including advanced information services.

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

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas 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;
- utilizing our expertise across our various businesses to improve overall performance;
- enhancing marketing channels to attract new customers;
- providing reliable and responsive customer service to retain existing customers;
- maintaining a capital structure that enables us to access capital as needed;
- maintaining a consistent and competitive dividend for shareholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

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(b) Highlights and Recent Developments

Our net income for 2011 was $27.6 million, or $2.87 per share (diluted), compared to $26.1 million, or $2.73 per share (diluted), and $15.9 million, or $2.15 per share (diluted), for 2010 and 2009, respectively. Our results for 2009 included only the results of FPU after the acquisition on October 28, 2009.

Our operations are primarily related to natural gas, electricity and propane, both in the regulated and unregulated sectors and are generally located on the Delmarva Peninsula and in Florida. We also have an advanced information services subsidiary, which provides both products and consulting services. The following is a summary of key factors affecting our businesses and their impacts on our results. More detailed discussion and analysis are provided in the Results of Operations section.

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

The weather in 2011 on the Delmarva Peninsula and in Florida was six percent and 18 percent, respectively, warmer than normal. HDD in 2011 on the Delmarva Peninsula and Florida were 4,221 and 753, respectively, compared to the normal HDD of 4,499 and 920, respectively. The weather in 2010 on the Delmarva Peninsula and in Florida was seven percent and 74 percent, respectively, colder than normal. On the year-over-year basis, the weather in 2011 on the Delmarva Peninsula and in Florida was 13 percent, or 610 HDD, and 50 percent, or 748 HDD, respectively, warmer than the weather in 2010. This year-over-year weather variance significantly reduced our customers consumption and decreased our gross margin by approximately $5.2 million in 2011, compared to 2010. Compared to normal weather, we estimated decreased gross margin of $2.8 million in 2011 as a result of the lower customer consumption, due primarily to warmer-than-normal temperatures in 2011 on the Delmarva Peninsula and in Florida.

CDD remained relatively unchanged in 2011 and 2010 (2,858 CDD in Florida in 2011, compared to 2,859 CDD in Florida in 2010) and did not result in a significant variance in our gross margin.

Growth. We continue to see growth in our natural gas businesses from our efforts over the past several years to expand our services by delivering clean-burning, environmentally friendly natural gas to customers. We are identifying and developing additional opportunities that will generate growth over the next several years.

Eastern Shore, our natural gas transmission subsidiary, continues to extend its natural gas transmission system on the Delmarva Peninsula. Continued expansion of the transmission system and new services are in response to increased demand for natural gas services on the Delmarva Peninsula by both our Delmarva natural gas distribution operation and other unaffiliated industrial customers directly connected to our transmission system. Eastern Shore generated additional gross margin of $3.0 million in 2011, compared to 2010, from the following new transportation services:

- Eastern Shore s new service on the eight-mile mainline extension to interconnect with TETLP s pipeline system, which commenced in January 2011, generated $2.0 million of the additional gross margin in 2011. This new service is expected to generate gross margin of $1.9 million in 2012 and $2.1 million annually thereafter.

- Eastern Shore entered into two additional transportation service agreements with an existing industrial customer, one for the period from May 2011 to April 2021 and the other for the period from November 2011 to October 2012. These additional services generated additional gross margin of $243,000 and $168,000, respectively, in 2011. The 10-year service from May 2011 to April 2021 is expected to generate annual gross margin of $362,000. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $842,000 in 2012.

Also generating additional gross margin of $542,000 in 2011, compared to 2010, were other mainline transportation services that commenced in May 2010, November 2010 and November 2011, as a result of Eastern Shore s system expansion projects. These other mainline transportation services are expected to generate an estimated annual gross margin of $1.6 million, $758,000 of which was recorded in 2011.

In 2011, Eastern Shore began construction of its mainline extension projects to serve southern Delaware and Cecil and Worcester Counties, Maryland. These mainline extension projects are expected to be placed in service in the first half of 2012.

On December 22, 2011, Eastern Shore entered into a Precedent Agreement with NRG Energy Center Dover LLC (NRG) to provide firm natural gas transportation service to NRG s electric power generation plant in Dover, Delaware. Eastern Shore has previously provided interruptible service to NRG at this plant. To provide the firm service, Eastern Shore will construct new facilities at an estimated cost of $12.5 million to $15.0 million. The Precedent Agreement provides that upon satisfying certain conditions, Eastern Shore and NRG will sign a 15-year firm transportation service agreement for a maximum daily quantity of 13,440 Dts/d. This service is projected to commence in May 2013 and is expected to generate estimated annual gross margin of $2.4 to $2.8 million. If the necessary facilities are not operational on or before December 31, 2013, or if Eastern Shore is not able to provide the firm transportation service by utilizing other capacity, either Eastern Shore or NRG may terminate both the Precedent Agreement and the firm transportation service agreement. Eastern Shore and NRG are proceeding with obtaining necessary governmental and regulatory approvals associated with this service.

Our Delmarva natural gas distribution operation has successfully expanded its service to large commercial and industrial customers and has continued its efforts to extend natural gas service to Lewes, Delaware and Cecil and Worcester Counties, Maryland. Since July 2010, our Delmarva natural gas distribution operation added 20 large commercial and industrial customers with an estimated annual gross margin of $2.1 million ($1.2 million and $196,000 was recorded in 2011 and 2010, respectively, from these new customers), including two industrial customers in Lewes, Delaware. In addition to these new customers, we entered into a new agreement in August 2011 to provide natural gas service to an existing industrial customer at two of its facilities located in southern Delaware. These new services are expected to begin in the first quarter of 2012 and generate estimated annual gross margin equivalent to 415 residential customers. Our Delmarva natural gas distribution operation also experienced two-percent growth in residential customers, generating additional gross margin of $429,000 in 2011.

Our Florida natural gas distribution operation generated $771,000 of additional gross margin in 2011, primarily from a two-percent growth in commercial and industrial customers. In addition, 700 new customers, added as a result of our purchase of the IGC operating assets in August 2010, generated $377,000 of additional gross margin during 2011, due to the inclusion of a full year of results. In January 2012, Peninsula Pipeline executed an agreement with Peoples Gas for the joint construction, ownership and operation of a 16-mile pipeline from the Duval/Nassau county line to Amelia Island, Florida. This jointly owned pipeline will provide us with the ability to extend natural gas service to Nassau County. Peninsula Pipeline s portion of the estimated cost in this project is approximately $5.7 million, with the completion of the construction projected to be in the second half of 2012.

Our Florida electric distribution operation did not experience significant customer growth in 2011.

Rates and Regulatory Matters. During 2011, we concluded two major regulatory proceedings. Following its agenda conference in December 2011, the Florida PSC issued an order in January 2012, approving the recovery of $34.2 million in acquisition adjustment and $2.2 million in merger-related costs in connection with our acquisition of FPU in 2009. In the order, the Florida PSC also determined that no refund is required to customers from the 2010 earnings of our Florida natural gas distribution operation. The outcome of this Come-Back filing resulted in the reversal in the fourth quarter of 2011, of the $750,000 regulatory reserve, which was previously accrued in the third and fourth quarters of 2010. This reserve was previously accrued based on the contingent regulatory risk associated with our Florida operation s natural gas earnings, merger benefits and recovery of the acquisition adjustment.

The inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these assets through amortization expense will increase our earnings and cash flows above what we would have been able to achieve absent the regulatory approval. The acquisition adjustment and merger-related costs will be amortized over 30 years and five years, respectively, beginning in November 2009. Based upon the effective date and outcome of the order, amortization will be reflected as expense in our consolidated statement of income beginning in 2012. We will record $2.4 million ($1.4 million, net of tax) in amortization expense related to these assets in 2012 and 2013, $2.3 million ($1.4 million, net of tax) in 2014 and $1.8 million ($1.1 million, net of tax) annually, thereafter until 2039.

On January 24, 2012, the FERC approved the rate case settlement for Eastern Shore. The settlement provides for a pre-tax return of 13.9 percent. Also included in the settlement is a negotiated rate adjustment, effective November 1, 2011, associated with the phase-in of an additional 15,000 Dts/d of new transportation service on Eastern Shore s eight-mile extension to interconnect with TETLP s pipeline system. This rate adjustment reduces the rate per Dt of the service on this eight-mile extension by reflecting the increased service of 15,000 Dts/d with no additional revenue. This rate adjustment effectively offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm service. In 2011, we recorded $409,000 in additional gross margin as a result of implementing the new rates pursuant to the settlement.

In addition to regulatory proceedings, we are currently involved in a legal dispute over alleged breaches of the Franchise Agreement by FPU. The alleging City seeks a declaratory judgment that the City has the right to exercise its option to purchase FPU s electric distribution property in the City. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City. FPU serves approximately 3,000 customers in the City. In 2011, we incurred approximately $537,000 in legal costs associated with this electric franchise dispute.

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

Our propane distribution operations generated additional gross margin of $2.2 million due to higher retail margins per gallon in 2011, compared to 2010. Propane retail margins per gallon on the Delmarva Peninsula during 2011 returned to more normal levels, compared to the lower margins per gallon reported during 2010, which was caused by colder temperatures and the high cost of spot purchases during the first quarter of 2010. Also contributing to the gross margin increase were higher margins per gallon in Florida as the Florida propane operation continued to adjust its retail pricing in response to market opportunities, which contributed to the increased retail margins.

Higher price volatility in the wholesale propane market resulted in a 22-percent increase in Xeron s trading volumes in 2011, compared to 2010, and generated $431,000 of additional gross margin.

Advanced Information Services. In September 2011, BravePoint, our advanced information services subsidiary, released a new product, ProfitZoom , an integrated system encompassing financial, job costing and service management modules, which was designed specifically for the fire protection and specialty contracting industries. ProfitZoom was built as a successor product to another software solution that BravePoint previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom product in 2009. BravePoint s operating income declined by $858,000 in 2011, compared to 2010, as a result of additional costs incurred in connection with the launch of ProfitZoom ™. BravePoint has successfully implemented ProfitZoom™ for three customers and two additional customers have executed contracts to implement it in early 2012. In addition, BravePoint is utilizing a component of ProfitZoom™, Application Evolution™ , to provide services to new and existing customers. Application Evolution™ is currently being used to provide services to seven customers and BravePoint currently has contracts for services to four additional customers in 2012. BravePoint recorded $572,000 in revenue in 2011 from these new contracts with approximately $522,000 in additional revenue associated with these contracts to be recognized in the first half of 2012. Several other sales proposals are under consideration by current and other potential customers.

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(c) 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 discussed with our Audit Committee.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (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 under the heading Notes to the Consolidated Financial Statements Note A, Summary of Accounting Policies, we have recorded regulatory assets of $81.1 million and regulatory liabilities of $46.8 million at December 31, 2011. If we were required to terminate 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 Assets and Liabilities

As more fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note P, Environmental Commitments and Contingencies, we are currently participating in the investigation, assessment or remediation of six former MGP sites. We have also been in discussions with MDE regarding a seventh former MGP site. Amounts have been recorded as environmental liabilities and associated environmental regulatory assets based on estimates of future costs to remediate these sites, which are provided by independent consultants, and future recovery of those costs in rates. At December 31, 2011, we had $11.3 million in environmental liabilities, representing our estimate of such future costs. We also had $6.7 million in regulatory and other assets, representing the amount of our environmental remediation costs to be recovered in future rates. There is uncertainty in these amounts, because the United States Environmental Protection Agency (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 appropriate GAAP. 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.

The following is a review of our use of derivative instruments at December 31, 2011 and 2010:

During 2011 and 2010, our natural gas distribution, electric distribution, propane distribution and natural gas marketing operations entered into physical contracts for the purchase or sale of natural gas, electricity and propane. These contracts 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 expected to be used and sold by our operations over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

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During 2011 and 2010, the propane distribution operation entered into put options to protect against the decline in propane prices and related potential inventory losses associated with the propane purchased for the propane price cap program in the upcoming heating season. We accounted for the put option entered in August 2011 as a fair value hedge. Accordingly, the change in the fair value of this put option of $23,000 during 2011 effectively reduced propane inventory balance. For the put option entered in October 2010, we elected not to designate it as a fair value hedge although it met all the accounting requirements. Accordingly, the change in the fair value of this put option of $168,000 during 2010 reduced our earnings. At December 31, 2011 and 2010, these put options had the fair value of $68,000 and $0, respectively.

Xeron, our propane wholesale marketing subsidiary, enters into forward, futures and other contracts that are considered derivatives. These contracts are mark-to-market, using prices at the end of each reporting period, and unrealized gains or losses are recorded in the Consolidated Statement of Income as revenue or expense. These contracts generally mature within one year and are almost exclusively for propane commodities. For 2011 and 2010, these contracts had net unrealized gains of $41,000 and $284,000, respectively. We had $1.7 million in mark-to-market energy assets and $1.5 million in mark-to-market energy liabilities related to these contracts at December 31, 2011. We had $1.6 million in mark-to-market energy assets and $1.5 million in mark-to-market energy liabilities related to these contracts at December 31, 2010.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of the state in which we 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. In connection with this accrual, we must estimate amounts of natural gas and electricity that have been delivered to our systems but have not been accounted for (commonly known as unaccounted for gas and electricity). 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.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in the statement of income. For certain propane distribution customers without meters and advanced information services customers, 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 purchased fuel cost recovery mechanism. This mechanism provides us with a method of adjusting billing rates to customers 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 purchased 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.

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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 under the heading Notes to the Consolidated Financial Statements Note M, Employee Benefit Plans, 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.

The total pension and other postretirement benefit costs included in operating income were $1.9 million, $2.0 million and $892,000, in 2011, 2010 and 2009, respectively. The total costs for 2011 included $436,000 of settlement charges associated with the retirement of a former executive. We expect to record pension and postretirement benefit costs of approximately $1.9 million for 2012. Actuarial assumptions affecting 2012 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 4.25 percent and 4.50 percent for Chesapeake s plans 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.

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 discount rate could change our pension and postretirement costs by approximately $34,000. A 0.25 percent change in the rate of return could change our pension cost by approximately $108,000 and will not have an impact on the postretirement and SERP plans because these plans are not funded.

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(d) Results of Operations

(in thousands except per share)

For the Years Ended December 31,	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
Business Segment:						
Regulated Energy	**$ 44,204**	$ 43,509	$ 695	$ 43,509	$ 26,900	$ 16,609
Unregulated Energy	**9,326**	7,908	1,418	7,908	8,158	(250)
Other	**175**	513	(338)	513	(1,322)	1,835
Operating Income	**53,705**	51,930	1,775	51,930	33,736	18,194
Other Income	**906**	195	711	195	165	30
Interest Charges	**9,000**	9,146	(146)	9,146	7,086	2,060
Income Taxes	**17,989**	16,923	1,066	16,923	10,918	6,005
Net Income	**$ 27,622**	$ 26,056	$ 1,566	$ 26,056	$ 15,897	$ 10,159
Earnings Per Share of Common Stock						
Basic	**$ 2.89**	$ 2.75	$ 0.14	$ 2.75	$ 2.17	$ 0.58
Diluted	**$ 2.87**	$ 2.73	$ 0.14	$ 2.73	$ 2.15	$ 0.58

2011 compared to 2010

Our net income increased by approximately $1.6 million, or $0.14 per share (diluted) in 2011, compared to 2010. An increase in operating income of $1.8 million and an increase in other income of $711,000 contributed to the increase in net income. The factors contributing to the increase in our operating and other income are as follows:

- New natural gas transportation services generated $3.0 million in additional gross margin.
- Growth in natural gas distribution customers generated $2.7 million in additional gross margin.
- Higher retail margins per gallon in the propane distribution operations increased gross margin by $2.2 million.
- Lower customer energy consumption, due primarily to warmer temperatures in 2011, compared to 2010, reduced gross margin by $5.2 million.
- Several unusual items affected our results:
  - A reversal in 2011 of the $750,000 reserve recorded in 2010 due to the regulatory approval for recovery of the acquisition premium and merger-related costs;
  - $959,000 in lower sales and gross receipts taxes, due to an accrual in 2010 of $698,000 for potential additional taxes and the reversal in 2011 of $261,000 of the accrual as a result of the collection of those taxes from customers;

The absence in 2011 of $660,000 of merger-related costs expensed in 2010;

A gain of $575,000 related to the proceeds received from an antitrust litigation settlement with a major propane supplier;

A $553,000 gain from the sale of a non-operating Internet Protocol address asset;

Severance and pension settlements charges of $1.3 million;

BravePoint s decline in operating income of $858,000 as a result of the launch of ProfitZoom™; and

Additional legal costs of $537,000 were incurred in 2011 as a result of an electric franchise dispute, for which we could incur a similar level of costs in 2012.

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2010 compared to 2009

Our net income increased by approximately $10.2 million, or $0.58 per share (diluted) in 2010, compared to 2009. An increase in operating income of $18.2 million, offset partially by higher interest expense of $2.1 million, contributed to the increase in net income. The factors contributing to the increase in our operating income are as follows:

Inclusion of the full year results of FPU in 2010, compared to inclusion in 2009 of only the results after the acquisition on October 28, 2009;

Continued growth and expansion of our natural gas distribution and transmission businesses and propane distribution business on the Delmarva Peninsula;

Rate increase in Chesapeake s Florida natural gas distribution division;

Favorable weather impact; and

Improved results in our advanced information services business.

These increases were partially offset by a decline in earnings from our natural gas marketing business, due primarily to the absence of spot sales to one industrial customer, and our propane wholesale marketing business.

Regulated Energy

For the Years Ended December 31, (in thousands)	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
Revenue	**$ 256,773**	$ 269,934	($ 13,161)	$ 269,934	$ 139,099	$ 130,835
Cost of sales	**128,111**	145,207	(17,096)	145,207	64,803	80,404
Gross margin	**128,662**	124,727	3,935	124,727	74,296	50,431
Operations & maintenance	**59,915**	57,571	2,344	57,571	32,569	25,002
Depreciation & amortization	**16,650**	14,815	1,835	14,815	8,866	5,949
Other taxes	**7,893**	8,832	(939)	8,832	5,961	2,871
Other operating expenses	**84,458**	81,218	3,240	81,218	47,396	33,822
Operating Income	**$ 44,204**	$ 43,509	$ 695	$ 43,509	$ 26,900	$ 16,609

Weather and Customer Analysis

For the Years Ended December 31,	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
Delmarva Peninsula						
Actual HDD	**4,221**	4,831	(610)	4,831	4,729	102
10-year average HDD	**4,499**	4,528	(29)	4,528	4,462	66
Estimated gross margin per HDD	**$ 2,064**	$ 1,995	$ 69	$ 1,995	$ 2,429	$ (434)
Per residential customer added:						

Estimated gross margin	**$ 375**	$ 375	$ 0	$ 375	$ 375	$ 0
Estimated other operating expenses	**$ 111**	$ 105	$ 6	$ 105	$ 100	$ 5
Florida						
Actual HDD	**753**	1,501	(748)	1,501	911	590
10-year average HDD	**920**	863	57	863	849	14
Actual CDD	**2,858**	2,859	(1)	2,859	2,770	89
10-year average CDD	**2,718**	2,695	23	2,695	2,687	8
Average number of residential customers						
Delmarva natural gas distribution	**48,680**	47,638	1,042	47,638	46,717	921
Florida natural gas distribution	**61,525**	61,053	472	61,053	60,048	1,005
Florida electric distribution	**23,598**	23,589	9	23,589	23,679	(90)
Total	**133,803**	132,280	1,523	132,280	130,444	1,836

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2011 Compared to 2010

Operating income for the regulated energy segment increased by approximately $695,000, or two percent, in 2011, compared to 2010, which was generated from a gross margin increase of $3.9 million, offset by an operating expense increase of $3.2 million.

Gross Margin

Gross margin for our regulated energy segment increased by $3.9 million, or three percent in 2011, compared to 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $738,000 in 2011, compared to 2010. The factors contributing to this increase are as follows:

- Customer growth increased gross margin for our Delmarva natural gas distribution operation by approximately $1.6 million in 2011, compared to 2010. Gross margin from commercial and industrial customers for our Delmarva natural gas distribution operation increased by $1.2 million in 2011, due primarily to the addition of 20 large commercial and industrial customers since June 2010. These 20 new customers are expected to generate annual margin of approximately $2.1 million in 2012, $1.2 million of which was recorded in 2011. Two-percent growth in residential customers generated an additional $429,000 in gross margin for our Delmarva natural gas distribution operation.

- The increase in gross margin in 2011 was offset by $634,000 due to lower consumption during 2011, compared to 2010, primarily as a result of warmer weather on the Delmarva Peninsula. In 2011, HDD decreased by 610, or 13 percent on the Delmarva Peninsula, compared to 2010. This decrease in gross margin is mainly related to our Delaware division, as residential heating rates for our Maryland division are weather-normalized, and we typically do not experience an impact on gross margin from the weather for our residential customers in Maryland.

Gross margin for our Florida natural gas distribution operation increased by $198,000 in 2011, compared to 2010. The factors contributing to this increase are as follows:

- In January 2012, the Florida PSC issued an order, approving the recovery of $34.2 million in acquisition adjustment and $2.2 million in merger-related costs. In the order, the Florida PSC also determined that no refund is required to customers from the 2010 earnings of the Company s Florida natural gas distribution operation. The outcome of this Come-Back filing resulted in the reversal in the fourth quarter of 2011, of the $750,000 regulatory reserve, which was previously accrued in 2010 based on the contingent regulatory risk associated with Florida natural gas earnings, merger benefits and recovery of the acquisition adjustment.

- Customer growth for our Florida natural gas distribution operations in 2011 generated an increase in gross margin of $771,000, primarily as a result of a two-percent growth in commercial and industrial customers for our Florida natural gas distribution operations in 2011, compared to 2010. Also, the addition of 700 customers as a result of our purchase of the operating assets of IGC in August 2010, generated additional gross margin of $377,000 in 2011, compared to 2010, due to the inclusion of results for the full year.

- Gross margin decreased by $2.6 million, as a result of lower consumption during 2011, compared to 2010, due primarily to significantly warmer weather during the heating season. HDD in Florida decreased by 748, or 50 percent in 2011, compared to 2010.

Our natural gas transmission operations achieved gross margin growth of $3.7 million in 2011 compared to 2010. The factors contributing to this increase are as follows:

In January 2011, Eastern Shore commenced new transportation service for 20,000 Dts/d of capacity associated with its eight-mile mainline extension to interconnect with TETLP s pipeline system and generated gross margin of $2.0 million in 2011 from this service. Gross margin generated from this eight-mile extension, including the phase-in of additional service and the effect of the rate case settlement previously described, is expected to be $1.9 million in 2012 and $2.1 million annually thereafter.

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Also generating additional gross margin of $542,000 in 2011 were other mainline transportation services that commenced in May 2010, November 2010 and November 2011, as a result of Eastern Shore s system expansion projects. These expansions added 4,409 Dts/d of capacity and are expected to generate an estimated annual gross margin of $1.6 million, $758,000 of which was recorded in 2011.

Eastern Shore entered into two additional transportation services agreements with an existing industrial customer, one for the period from May 2011 to April 2021 for an additional 3,405 Dts/d and the other one for the period from November 2011 to October 2012 for an additional 9,514 Dts/d. These additional services generated additional gross margin of $243,000 and $168,000, respectively, in 2011. The 10-year service from May 2011 to April 2021 is expected to generate annual gross margin of $362,000. The one-year service from November 2011 to October 2012 is expected to generate gross margin of $842,000 in 2012.

On January 24, 2012, the FERC approved the rate case settlement for Eastern Shore. The settlement provides a pre-tax return of 13.9 percent. We recorded $409,000 in additional gross margin in 2011 as a result of the settlement.

The foregoing increases to gross margin were partially offset by decreased margins of $66,000 from the full year impact of two transportation service contracts, which expired in April 2010.

Gross margin for our Florida electric distribution operation decreased by $760,000 in 2011, compared to 2010, due primarily to lower customer consumption during the heating season as a result of significantly warmer weather in 2011 during the heating season, compared to 2010. HDD in Florida decreased by 50 percent (748 HDD) in 2011, compared to 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $3.2 million in 2011, due largely to the following factors:

$1.2 million in higher depreciation expense and asset removal costs from capital investments;

$1.1 million in non-recurring severance charges and pension settlement charges;

$537,000 in increased legal costs associated with an electric franchise dispute;

$403,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements;

$375,000 in increased amortization expense related to the change in the recovery period of project costs associated with Eastern Shore s former Energylink expansion project;

$355,000 in higher vehicle fuel costs; and

$896,000 in lower taxes other than income taxes, due to an accrual in 2010 for potential additional sales taxes and gross receipts taxes and the reversal of a portion of the accrual in 2011 as a result of collection and remittance of those taxes.

2010 Compared to 2009

Operating income for the regulated energy segment increased by approximately $16.6 million, or 62 percent, in 2010, compared to 2009, which was generated from a gross margin increase of $50.4 million, offset partially by an operating expense increase of $33.8 million. Our 2010 results included 12 months of FPU s operating results, whereas 2009 included only two months.

Gross Margin

Gross margin for our regulated energy segment increased by $50.4 million, or 68 percent. Of the $50.4 million increase, Chesapeake s legacy regulated energy businesses generated $5.2 million of the increase, or 10 percent. FPU s natural gas and electric distribution operations contributed $45.2 million of this increase. FPU s results in 2009 have been included in our results since the completion of the merger on October 28, 2009. Our results for 2010 included FPU s results for the full year.

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Our Delmarva natural gas distribution operation generated an increase in gross margin of $1.4 million in 2010. The factors contributing to this increase were as follows:

- $1.1 million of the gross margin increase was a result of a two-percent increase in residential customers as well as additional growth in commercial and industrial customers on the Delmarva Peninsula. Residential, commercial and industrial growth by our Delaware division generated $525,000, $163,000 and $313,000, respectively, of the gross margin increase, and the customer growth by our Maryland division contributed $97,000 to the gross margin increase. In 2010, our Delmarva natural gas distribution operations also added 10 large commercial and industrial customers with total expected annualized margin of $748,000, of which $196,000 has been reflected in 2010 s results.

- Colder weather on the Delmarva Peninsula generated an additional $365,000 to gross margin as HDD increased by 102, or two percent, in 2010, compared to 2009. This increased gross margin is primarily related to our Delaware division, as residential heating rates for our Maryland division are weather-normalized, and we typically do not experience an impact on gross margin from the weather for our residential customers in Maryland.

- A decline in non-weather-related customer consumption, primarily by residential customers of our Delaware division, decreased gross margin by $111,000.

Our Florida natural gas distribution operation experienced an increase in gross margin of $32.5 million in 2010. The factors contributing to this increase were as follows:

- FPU s natural gas distribution operation generated $36.1 million in gross margin for 2010, which includes $148,000 of gross margin generated by the purchase of operating assets from IGC on August 9, 2010. Gross margin from FPU s natural gas distribution operation in 2009 was $6.4 million. Gross margin from FPU s natural gas distribution operation in 2010 was positively affected by an annual rate increase of approximately $8.0 million, effective January 14, 2010, colder temperatures in Florida and growth in commercial and industrial customers. Included in gross margin from FPU s natural gas distribution operation for 2010 was the impact of a $750,000 accrual related to the regulatory risk associated with its earnings, merger benefits and recovery of purchase premium. This accrual was subsequently reversed in 2011, pursuant to the outcome of the Come-Back filing.

- Gross margin from Chesapeake s Florida division increased by $2.9 million, primarily as a result of an annual rate increase of approximately $2.5 million, which became effective on January 14, 2010. The colder temperatures in 2010 also generated an additional $247,000 in gross margin in 2010, compared to 2009.

Our natural gas transmission operations achieved gross margin growth of $952,000 in 2010. The factors contributing to this increase were as follows:

- New transportation services implemented by Eastern Shore in November 2009, May 2010 and November 2010 as a result of its system expansion projects generated an additional $1.1 million to gross margin in 2010, compared to 2009.

- New firm transportation service for an industrial customer for the period from November 2009 to October 2012 added $329,000 to gross margin for 2010. Partially offsetting the additional gross margin generated by this new firm transportation service was the margin of $232,000 in 2009 from the temporary interruptible service provided to the same customer. This temporary increase in service did not recur in 2010.

Eastern Shore changed its rates effective April 2009 to recover specific project costs in accordance with the terms of precedent agreements with certain customers. These rates generated $508,000 and $381,000 in gross margin in 2010 and 2009, respectively. Eastern Shore and the customers agreed to shorten the recovery period, starting in March 2011.

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Offsetting the foregoing increases to gross margin, Eastern Shore received notices from two customers of their intentions not to renew their firm transportation service contracts, which expired in November 2009 and April 2010, decreasing gross margin by $341,000 for 2010.

Our Florida electric distribution operation, which was acquired in the FPU merger, generated gross margin of $18.4 million in 2010, compared to $2.8 million in gross margin generated in 2009. FPU s results in 2009 were included in our results only after the completion of the merger in 2009. Gross margin from our electric distribution operation was positively affected by colder temperatures in the winter months and warmer temperatures in the summer months in 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $33.8 million, or 71 percent, in 2010, of which $32.4 million was related to other operating expenses of FPU. The remaining increase of $2.4 million, or a five percent increase over other operating expenses in 2009, exclusive of other operating expenses of FPU, was due primarily to the following factors:

$705,000 in increased payroll and benefits, due primarily to annual salary increases and incentive pay as a result of improved performance;

$518,000 in higher depreciation and asset removal costs as a result of our increased capital investments made in 2010 and 2009 to support growth;

$349,000 in increased regulatory expenses, due primarily to costs associated with Eastern Shore s rate case filing in 2010 and regulatory discussions involving and preparation of the Come-Back filing for recovery of the purchase premium in Florida; and

$63,000 in increased taxes other than income taxes, due primarily to increased gross receipts tax.

Unregulated Energy

For the Years Ended December 31,	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
(in thousands)						
Revenue	**$ 149,586**	$ 146,793	$ 2,793	$ 146,793	$ 119,973	$ 26,820
Cost of sales	**112,415**	110,680	1,735	110,680	90,408	20,272
Gross margin	**37,171**	36,113	1,058	36,113	29,565	6,548
Operations & maintenance	**23,312**	23,140	172	23,140	18,016	5,124
Depreciation & amortization	**3,090**	3,433	(343)	3,433	2,415	1,018
Other taxes	**1,443**	1,632	(189)	1,632	976	656
Other operating expenses	**27,845**	28,205	(360)	28,205	21,407	6,798
Operating Income	**$ 9,326**	$ 7,908	$ 1,418	$ 7,908	$ 8,158	$ (250)

Weather Analysis Delmarva

For the Years Ended December 31,	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
Actual HDD	**4,221**	4,831	(610)	4,831	4,729	102
10-year average HDD	**4,499**	4,528	(29)	4,528	4,462	66
Estimated gross margin per HDD	**$ 2,869**	$ 2,611	$ 258	$ 2,611	$ 3,083	$ (472)

2011 Compared to 2010

Operating income for the unregulated energy segment increased by approximately $1.4 million, or 18 percent, in 2011 compared to 2010, which was attributable to an increase in gross margin of $1.1 million and a decrease in other operating expenses of $360,000.

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Gross Margin

Gross margin for our unregulated energy segment increased by $1.1 million, or three percent in 2011 compared to 2010.

Our Delmarva propane distribution operation experienced a decrease in gross margin of $265,000 in 2011, compared to 2010. The factors contributing to this decrease are as follows:

Warmer weather on the Delmarva Peninsula during 2011, compared to 2010 decreased customer consumption and reduced gross margin by $1.5 million as HDD decreased by 610, or 13 percent, in 2011, compared to 2010. Also, non-weather-related volumes sold in 2011 decreased, compared to 2010, as a result of the timing of bulk deliveries and reduced gross margin by $303,000.

The aforementioned decreases were partially offset by an increase in retail margins. Our Delmarva propane distribution operation generated additional gross margin of $736,000 due to higher retail margins per gallon during 2011, compared to 2010, as margins per gallon returned to more normal levels during the current year. Propane retail margins per gallon during the first half of 2010 were low, compared to historical levels, due to additional high-cost spot purchases incurred during the peak heating season to meet the weather-related increase in customer consumption. More normal temperatures and fewer spot purchases during 2011 resulted in margins per gallon returning to more normal levels.

A one-time gain of $575,000 was recorded in 2011 as a result of our share of proceeds received from an antitrust litigation settlement with a major propane supplier.

An increase in other fees generated additional gross margin of $217,000, due primarily to the continued growth and successful implementation of various pricing programs available to customers.

Our Florida propane distribution operation generated increased gross margin of $683,000 in 2011, compared to 2010. Higher retail margins per gallon, as we continued to adjust our retail pricing in response to market conditions, contributed $1.5 million in additional gross margin. Also generating $136,000 in gross margin in 2011 was a propane rail terminal agreement with a supplier to provide terminal and storage services from November 2010 to May 2011. These increases were partially offset by decreased gross margin of $964,000 as a result of lower non-weather-related consumption.

Xeron generated a $431,000 increase in gross margin in 2011, compared to 2010, due primarily to a 22-percent increase in Xeron s trading activity.

Gross margin generated by PESCO increased by $362,000 in 2011, compared to 2010. This increase was due to favorable imbalance resolutions in 2011 with third-party pipelines, with which PESCO contracts for natural gas supply. Revenues generated from favorable imbalance resolutions with intrastate pipelines are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Merchandise sales in Florida decreased in 2011, compared to 2010, resulting in lower gross margin of $153,000.

Other Operating Expenses

Other operating expenses for the unregulated energy segment decreased by $361,000 in 2011, compared to 2010. In 2010, we expensed $370,000 of the accrual related to the settlement of a propane class action litigation and recorded $351,000 in amortization expense associated with the favorable propane supply contracts acquired in the merger with FPU, which was recorded as an intangible asset. The absence of these expenses in 2011 resulted in a decrease in other operating expenses in 2011, compared to 2010. These decreases were partially offset by a $265,000 increase in vehicle fuel costs in 2011.

2010 Compared to 2009

Operating income for the unregulated energy segment decreased by approximately $250,000, or three percent, in 2010 compared to 2009, which was attributable to an increase in gross margin of $6.5 million, offset by an increase in other operating expenses of $6.8 million. A decline in operating income for the unregulated energy segment was largely attributable to the natural gas marketing business, which experienced a decrease in gross margin due primarily to the absence of spot sales to one industrial customer.

Gross Margin

Gross margin for our unregulated energy segment increased by $6.5 million, or 22 percent, for 2010, compared to 2009.

Our Delmarva propane distribution operation generated a gross margin increase of $1.0 million, as a result of the following factors:

Retail volumes sold increased by 1.6 million gallons, or seven percent, in 2010, which generated additional gross margin of $1.1 million. The addition of 436 community gas system customers and 1,000 other customers acquired in February 2010, as part of the purchase of the operating assets of a propane distributor serving Northampton and Accomack Counties in Virginia, contributed approximately 38 percent of this increase. The two-percent colder weather in 2010, compared to 2009, generated additional margin of $314,000. Timing of propane deliveries to our bulk customers contributed to the remaining increase in gross margin due to an increase in retail volumes.

Other fees increased by $340,000 in 2010 driven by customer participation in various pricing programs available to customers.

Retail margins per gallon decreased in 2010, compared to 2009, and decreased gross margin by $399,000. Retail margins per gallon during the first half of 2010 were low, compared to historical levels, due to additional high-cost spot purchases during the peak heating season. Retail margins per gallon during the first half of 2009 benefited from the inventory valuation adjustment recorded in late 2008, which lowered the propane inventory costs and, therefore, increased retail margins during the first half of 2009.

Our Florida propane distribution operation generated $9.4 million in 2010, compared to $3.2 million in 2009. The 2009 results include FPU s results for the two months after the completion of the merger. Also included in the gross margin increase for 2010 was approximately $767,000 in increased merchandise sales from FPU.

Gross margin for Xeron, our propane wholesale marketing operation, decreased by $441,000 in 2010 compared to 2009. Xeron s trading volumes decreased by 13 percent in 2010 compared to 2009.

In 2010, gross margin for our unregulated natural gas marketing subsidiary, PESCO, decreased by $1.0 million. In 2009, PESCO benefited from increased spot sales on the Delmarva Peninsula. Spot sales decreased in 2010, due primarily to one industrial customer. Spot sales are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $6.8 million in 2010. The Florida distribution operation and FPU s merchandise activities contributed $6.0 million to this increase. Included in other operating expenses for the Florida propane distribution operation in 2010 was approximately $370,000 expensed in the third and fourth quarters of 2010 for the settlement of a class action complaint (See Item 8 under the heading Notes to the Consolidated Financial Statements Note Q, Other Commitments and Contingencies). The remaining increase of $771,000 in other operating expenses was due primarily to increased payroll and benefit costs, higher non-income taxes due to increased sales taxes and increased propane delivery costs, partially offset by a decrease in bad debt expenses as a result of expanded credit and collection initiatives by PESCO.

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Other

For the Years Ended December 31,	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
(in thousands)						
Revenue	**$ 13,829**	$ 13,142	$ 687	$ 13,142	$ 11,998	$ 1,144
Cost of sales	**7,051**	6,316	735	6,316	6,036	280
Gross margin	**6,778**	6,826	(48)	6,826	5,962	864
Operations & maintenance	**5,515**	5,426	89	5,426	6,337	(911)
Depreciation & amortization	**413**	289	124	289	310	(21)
Other taxes	**676**	600	76	600	640	(40)
Other operating expenses	**6,604**	6,315	289	6,315	7,287	(972)
Operating Income (Loss) Other	**174**	511	(337)	511	(1,325)	1,836
Operating Income Eliminations	**1**	2	(1)	2	3	(1)
Operating Income (Loss)	**$ 175**	$ 513	(338)	$ 513	($ 1,322)	$ 1,835

2011 Compared to 2010

Operating income for the Other segment for 2011 was $175,000, representing a decrease of $338,000 from operating income of $513,000 for 2010. The decrease in operating income was attributable to lower operating income of $1.0 million from BravePoint, our advanced information services subsidiary, offset partially by the absence in 2011 of $660,000 in merger-related costs expensed in 2010.

BravePoint reported an operating loss of $270,000 in 2011, compared to operating income of $759,000 in 2010. During 2011, BravePoint incurred additional costs associated with the product development and release of a new product, ProfitZoom™. BravePoint has successfully implemented ProfitZoom™ for three customers and two additional customers have executed contracts to implement it in early 2012. In addition, BravePoint is utilizing a component of ProfitZoom™, Application Evolution™ to provide services to new and existing customers. Application Evolution™ is currently being used to provide services to seven customers and BravePoint currently has contracts for services to four additional customers in 2012. BravePoint recorded $572,000 in revenue in 2011 from these new contracts with approximately $522,000 in additional revenue associated with these contracts to be recognized in the first half of 2012. Several other sales proposals are under consideration by current and other potential customers.

2010 Compared to 2009

Operating income for the Other segment for 2010 was $513,000, compared to an operating loss of $1.3 million in 2009. The increase in operating results of $1.8 million was attributable to higher operating income of $982,000 from BravePoint and $818,000 in lower merger-related costs expensed in 2010.

BravePoint reported operating income of $759,000 in 2010, compared to an operating loss of $229,000 in 2009. BravePoint s gross margin increased by $801,000 in 2010, compared to 2009, due to an increase in revenue and gross margin from its professional database monitoring and support solution services and higher consulting revenues as a result of a seven-percent increase in the number of billable consulting hours in 2010 compared to 2009.

Other Income

Other income for 2011, 2010 and 2009 was $906,000, $195,000, and $165,000, respectively. Included in other income for 2011 was a $553,000 gain from the sale of a non-operating Internet Protocol address asset. The remaining balance in other income includes non-operating investment income, interest income, late fees charged to customers and gains or losses from the sale of assets.

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Interest Expense

2011 Compared to 2010

Total interest expense for 2011 decreased by $146,000, or two percent, compared to 2010. The decrease in interest expense is attributable primarily to a decrease of $651,000 in long-term interest expense as scheduled repayments decreased the outstanding principal balances. Offsetting this decrease was additional interest expense of $505,000 related to the $29 million long-term debt issuance of 5.68 percent unsecured senior notes on June 23, 2011 to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement we entered into with them on June 29, 2010. We used the proceeds to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds. These redemptions occurred in January 2010 and were previously financed by Chesapeake s short-term loan facilities.

2010 Compared to 2009

Total interest expense for 2010 increased by $2.1 million, or 29 percent, compared to 2009. The primary drivers of the increased interest expense were related to FPU, including:

- An increase in long-term interest expense of $1.3 million was related to interest on FPU s first mortgage bonds.

- Interest expense from a new term loan credit facility during 2010 was $491,000. We used $29.1 million of the new term loan facility for the redemptions of the FPU 4.90 percent and 6.85 percent first mortgage bonds redeemed in January 2010.

- Additional interest expense of $730,000 was related to interest on deposits from FPU s customers.

Offsetting the increased interest expense from FPU was lower non-FPU-related interest expense from Chesapeake s unsecured senior notes, as the principal balances decreased from scheduled payments, and lower additional short-term borrowings as a result of the timing of our capital expenditures and reduced working capital requirements, partially due to the increased bonus depreciation in 2010.

Income Taxes

2011 Compared to 2010

Income tax expense was $18.0 million in 2011, compared to $16.9 million in 2010. Our effective income tax rate for 2011 and 2010 remained unchanged at 39.4 percent.

2010 Compared to 2009

Income tax expense was $16.9 million in 2010, compared to $10.9 million in 2009, representing an increase of $6.0 million, as a result of increased taxable income in 2010. During 2009, we expensed approximately $871,000 in merger-related costs that we determined to be non-deductible for income tax purposes. Excluding the impact of these costs, our effective income tax rate for 2010 and 2009 remained unchanged at 39.4 percent.

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(e) Liquidity and Capital Resources

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investments 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 are one of our largest capital requirements. Our capital expenditures during 2011, 2010 and 2009 were $44.4 million, $47.0 million and $26.3 million, respectively. We experienced a significant increase in our capital expenditures in 2011 and 2010, compared to 2009, as a result of continued expansions of our natural gas distribution and transmission systems as well as inclusion of FPU s capital expenditures. We have budgeted $88.5 million for capital expenditures during 2012. This amount includes $75.9 million for the regulated energy segment, $3.1 million for the unregulated energy segment and $9.5 million for the Other segment. The amount for the regulated energy segment includes estimated capital expenditures for the following: natural gas distribution operations ($32.1 million), natural gas transmission operations ($40.4 million) and electric distribution operation ($3.4 million) for expansion and improvement of facilities. The amount for the unregulated energy segment includes estimated capital expenditures for the propane distribution operations for customer growth and replacement of equipment. The amount for the Other segment includes estimated capital expenditures of $515,000 for the advanced information services subsidiary with the remaining balance for improvements of various offices and operations centers, other general plant, computer software and hardware. We expect to fund the 2012 capital expenditures program from short-term borrowings, cash provided by operating activities, and other sources. 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.

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Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of December 31, 2011 and 2010:

(in thousands)	**December 31, 2011**		December 31, 2010	
Long-term debt, net of current maturities	**$ 110,285**	**31%**	$ 89,642	28%
Stockholders equity	**240,780**	**69%**	226,239	72%
Total capitalization, excluding short-term debt	**$ 351,065**	**100%**	$ 315,881	100%

(in thousands)	**December 31, 2011**		December 31, 2010	
Short-term debt	**$ 34,707**	**9%**	$ 63,958	17%
Long-term debt, including current maturities	**118,481**	**30%**	98,858	25%
Stockholders equity	**240,780**	**61%**	226,239	58%
Total capitalization, including short-term debt	**$ 393,968**	**100%**	$ 389,055	100%

In consummating the FPU merger in October 2009, we issued 2,487,910 shares of Chesapeake common stock, valued at approximately $75.7 million, in exchange for all outstanding common stock of FPU. Our balance sheet at the time of the merger also reflected FPU s long-term debt of $47.8 million as a result of the merger. Since the consummation of the merger, we have redeemed $29.1 million of FPU s long-term debt, which was held in the form of first mortgage bonds. We temporarily financed this early redemption of FPU s long-term debt through a new short-term credit facility from March 2010 to June 2011. On June 23, 2011, we issued $29.0 million of 5.68 percent Chesapeake s unsecured senior notes to repay the new short-term credit facility and permanently finance the redemption of FPU s long-term debt. We have also entered into an arrangement to refinance an additional $7.0 million of FPU s first mortgage bonds in 2013 with more competitively priced Chesapeake unsecured senior notes. As a result, only $8.0 million of the original $47.8 million of FPU debt as of the merger will be outstanding by 2013 in the form of secured first mortgage bonds.

As of December 31, 2011, 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, 2011, $67.3 million of Chesapeake s cumulative consolidated net income and $36.4 million of FPU s cumulative net income were free of such restrictions.

Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2011 and 2010 were $34.7 million and $64.0 million, respectively, at the weighted average interest rates of 1.57 percent and 1.77 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 fund temporarily portions of the capital expenditure program. As of December 31, 2011, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed 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. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at December 31, 2011 and 2010 were $30.5 million and $30.8 million, respectively. During 2011, 2010 and 2009, the average borrowings from these unsecured bank lines of credit were $11.0 million, $10.5 million and $13.0 million, respectively, at weighted average interest rates of 2.35 percent, 2.40 percent and 1.28 percent, respectively. The maximum month-end borrowings from these unsecured bank lines of credit during 2011, 2010 and 2009 were $35.4 million, $64.0 million and $33.0 million, respectively, which occurred during the fall and winter months when our working capital requirements were at the highest level. Also included in our outstanding short-term borrowings at December 31, 2011 and 2010 was $4.2 million and $4.1 million, respectively, in book overdrafts, which if presented would be funded through the bank lines of credit.

In addition to the four unsecured bank lines of credit, we entered into a new short-term credit facility for $29.1 million with an existing lender in March 2010 to temporarily finance the early redemption of FPU s long-term debt, as previously discussed. In connection with the issuance of Chesapeake s 5.68 percent unsecured notes in June 2011, we repaid the $29.1 million short-term credit facility.

Cash Flows Provided by Operating Activities

Our cash flows provided by operating activities were as follows:

For the Years Ended December 31,	**2011**	**2010**	**2009**
Net income	**$ 27,622**	$ 26,056	$ 15,897
Non-cash adjustments to net income	**42,884**	36,487	28,366
Changes in assets and liabilities	**615**	(1,425)	1,583
Net cash from operating activities	**$ 71,121**	$ 61,118	$ 45,846

Changes in our cash flows from operating activities are attributable primarily to changes in net income, non-cash adjustments for depreciation and income taxes and working capital. Changes in working capital are determined by a variety of factors, 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.

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

In 2011, our net cash flow provided by operating activities was $71.1 million, an increase of $10.0 million, compared to 2010. The increase was due primarily to the following:

- Net cash flows related to income taxes, which include deferred income taxes in non-cash adjustments to net income and the change in income taxes receivable, increased by $7.8 million during 2011, compared to 2010, due primarily to the 100-percent bonus depreciation deduction allowed in 2011, which reduced our income tax payments in the current period.

- Net cash flows from trading receivables and payables increased by $6.0 million, due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale marketing operation and an increase in net cash flows from receivables and payables in various other operations.

- Net cash flows from customer deposits increased by $3.1 million, due primarily to a large deposit received in 2011 from an industrial customer on the Delmarva Peninsula.

- Net cash flows from propane inventory, storage gas and other inventory decreased by $2.6 million, due primarily to additional pipes and other construction inventory purchased during 2011. Also contributing to this cash flow decrease is the period-over-period changes in the storage gas balance, which reduced our cash flows.

- Net cash flows from the changes in regulatory assets and liabilities decreased by approximately $5.2 million, primarily as a result of a reduction in fuel costs due and collected from regulated customers.

In 2010, our net cash flow provided by operating activities was $61.1 million, an increase of $15.3 million compared to 2009. The increase was due primarily to the following:

- Net cash flows from changes in accounts receivable and accounts payable were due primarily to the inclusion of FPU s accounts and the timing of collections and payments of trading contracts entered into by our propane wholesale and marketing operation.

- Net income increased by $10.2 million. A full year s results for FPU and organic growth within Chesapeake s legacy businesses contributed to this increase.

- Non-cash adjustments to net income increased by $12.4 million due primarily to higher depreciation and amortization, changes in deferred income taxes, higher employee benefits and compensation and an increase in share based compensation. Higher depreciation and amortization was due to the inclusion of FPU and an increase in capital investments. The increase in deferred income taxes was a result of bonus depreciation in 2010, which significantly reduced our income tax payment obligations in 2010.

- The decrease in income tax receivables was due primarily to the receipt of large refunds in 2009 due to higher tax deductions in 2009 and 2008 and a decrease in taxes payable due to bonus depreciation in 2010.

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Cash Flows Used in Investing Activities

In 2011, net cash flows used in investing activities totaled $47.8 million, representing a decrease of $1.1 million compared to 2010. In 2010, net cash flows used by investing activities totaled $48.9 million, an increase of $25.7 million compared to 2009.

Cash utilized for capital expenditures was $47.0 million, $45.6 million and $26.7 million for 2011, 2010, and 2009, respectively.

In 2011, we invested $300,000 in equity securities and paid $790,000 to acquire certain Florida propane assets. In 2010, we invested $1.6 million in equity securities and paid $1.2 million and $310,000 for certain natural gas distribution assets in Florida and propane distribution assets in Virginia.

In 2009, we received $3.5 million in proceeds from an investment account related to future environmental costs, as we transferred the amount to our general account that invests in overnight income-producing securities. We also acquired $359,000 in cash, net of cash paid, in the FPU merger in 2009.

Environmental expenditures exceeded amounts recovered through rates charged to customers in 2011, 2010 and 2009 by $645,000, $290,000 and $418,000, respectively.

We received $553,000 in 2011 in connection with a sale of a non-operating Internet Protocol address asset.

Cash Flows Provided by/Used in Financing Activities

In 2011 and 2010, net cash flows used by financing activities totaled $22.3 million and $13.4 million, respectively, compared to net cash flows used by financing activities of $21.4 million in 2009. Significant financing activities included the following:

We repaid $9.1 million, $36.9 million and $10.9 million of long-term debt in 2011, 2010 and 2009, respectively. Included in the long-term debt repayment during 2010 was the redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturities by using the proceeds from a new short-term credit facility with an existing lender. During 2011, we issued $29.0 million of Chesapeake s 5.68 percent unsecured senior notes and used the proceeds to repay the new short-term credit facility and permanently finance the redemption of FPU bonds.

During 2011 and 2009, we reduced our short-term borrowing by $241,000 and $3.8 million, respectively. During 2010, we increased our short-term borrowing by $1.6 million.

We paid $11.7 million, $11.0 million and $8.0 million in cash dividends in 2011, 2010 and 2009, respectively. An increase in cash dividends paid in each year reflects the growth in the annualized dividend rate. Dividends paid in 2011 and 2010 also reflect a larger number of shares outstanding as a result of issuance of our shares in exchange for the FPU shares in the merger.

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Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2011:

	Payments Due by Period				
Contractual Obligations *(in thousands)*	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
Long-term debt [1]	$ 8,196	$ 20,527	$ 18,273	$ 71,546	$ 118,542
Operating leases [2]	1,074	1,727	1,466	2,703	6,970
Purchase obligations [3]					
Transmission capacity	19,362	38,784	28,541	75,673	162,360
Storage Natural Gas	2,475	3,465	2,090	3,071	11,101
Commodities	46,671	277			46,948
Electric supply	13,195	28,082	30,430	44,196	115,903
Forward purchase contracts Propane[4]	17,451				17,451
Unfunded benefits [5]	392	861	1,052	5,461	7,766
Funded benefits [6]	2,595	131	67	1,360	4,153
Total Contractual Obligations	**$ 111,411**	**$ 93,854**	**$ 81,919**	**$ 204,010**	**$ 491,194**

(1) Principal payments on long-term debt, see Item 8 under the heading Notes to the Consolidated Financial Statements - Note J, Long-term Debt , for additional discussion of this item. The expected interest payments on long-term debt are $7.6 million, $13.4 million, $10.5 million and $18.3 million, respectively, for the periods indicated above. Expected interest payments for all periods total $49.8 million.

(2) See Item 8 under the heading Notes to the Consolidated Financial Statements - Note L, Lease Obligations, for additional discussion of this item.

(3) See Item 8 under the heading Notes to the Consolidated Financial Statement - Note P, Other Commitments and Contingencies, in the Notes to the Consolidated Financial Statements for further information.

(4) The Company has also entered into forward sale contracts. See Market Risk of the Management s Discussion and Analysis for further information.

(5) We have recorded long-term liabilities of $7.8 million at December 31, 2011 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.

(6) We have recorded long-term liabilities of $24.7 million at December 31, 2011 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 our balance sheets. The Contractual Obligations table above includes $2.5 million, reflecting the expected payments the Company will make to the trust funds in 2012. 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 under the heading Notes to the Consolidated Financial Statements - Note M, Employee Benefit Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling $1.7 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, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary 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, 2011 was $27.6 million, with the guarantees expiring on various dates through December 2012.

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In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 2, 2012, 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 $656,000, which expires on December 2, 2012, as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed the letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of December 31, 2011. 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 $2.5 million to TETLP related to the Precedent Agreement, which is further described in Item 8 under the heading, Notes to the Consolidated Financial Statements Note Q, Other Commitments and Contingencies.

(f) Rate Filings and Other Regulatory Activities

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the PSCs in their respective states; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At December 31, 2011, Chesapeake was involved in rate filings and/or regulatory matters in each of the jurisdictions in which it operates. Each of these rate filings or regulatory matters is fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note O, Rates and Other Regulatory Activities.

(g) Environmental Matters

We continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites (see Item 8 under the heading Notes to the Consolidated Financial Statements Note P, Environmental Commitments and Contingencies for further detail on each site). We believe that future costs associated with these sites will be recoverable in rates or through sharing arrangements with, or contributions by, other responsible parties.

(h) Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses in value based on changes in interest rates after issuance, to the extent such losses are not recovered through a regulatory process. Our outstanding long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures (see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-term Debt for annual maturities of consolidated long-term debt). All of our outstanding long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of outstanding long-term debt, including current maturities, was $118.5 million at December 31, 2011, as compared to a fair value of $142.3 million, based on a discounted cash flow methodology that incorporates a market interest rate that is based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 5.4 million gallons (including leased storage and rail cars) of propane during the winter season to meet our customers peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

In August 2011, our Delmarva propane distribution operation entered into a put option to protect against the decline 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. This put option is exercised if the propane prices fall below the strike price of $1.445 per gallon in January through March of 2012 and we will receive the difference between the market price and the strike price during those months. We paid $91,000 to purchase the put option. We account for this put option as a fair value hedge. As of December 31, 2011, the put option had a fair value of $68,000. The change in the fair value of the put option effectively reduced our propane inventory balance.

In October 2010, Sharp entered into put options to protect against the decline in propane prices and related potential inventory losses associated with 1,470,000 gallons purchased for the propane price cap program in the upcoming heating season. This put option would be exercised if the propane prices fell below the strike prices of $1.251 per gallon and $1.230 per gallon in January and February of 2011, respectively, at which point we would have received the difference between the market price and the strike price during those months. We paid $168,000 to purchase the put option. Although the put option met the accounting requirements for fair value hedge, we elected not to designate it as a fair value hedge and accounted for it on a mark-to-market basis. As of December 31, 2010, the put option had no fair value. The change in the fair value of the put option reduced our earnings in 2010.

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of natural gas liquids to us, or the counterparty or by booking out the transaction. Booking out is a procedure for financially settling a contract in lieu of the physical delivery of energy. The propane wholesale marketing operation also enters into futures contracts that are traded on the New York Mercantile Exchange. 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.

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The forward and futures contracts entered into by our propane wholesale marketing subsidiary are for trading 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, 2011 and 2010 is presented in the following tables:

At December 31, 2011	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	12,075,000	$1.3100	$1.6063	$1.4785
Purchase	11,928,000	$1.3050	$1.6000	$1.4630
Other Contract				
Put option	630,000	$0.1080		$0.1450

Estimated market prices and weighted average contract prices are in dollars per gallon.

All contracts expire by the end of the first quarter of 2012.

At December 31, 2010	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	13,523,496	$1.0350	$1.4100	$1.2192
Purchase	12,914,496	$1.0150	$1.3779	$1.2093
Other Contract				
Put option	1,470,000	$		$0.1150

Estimated market prices and weighted average contract prices are in dollars per gallon.

All contracts expire by the end of the second quarter of 2011.

At December 31, 2011 and 2010, 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)	**2011**	**2010**
Mark-to-market energy assets, including put option	**$ 1,754**	$ 1,642
Mark-to-market energy liabilities	**$ 1,496**	$ 1,492

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

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(i) Competition

Our natural gas and electric distribution operations and our natural gas transmission operation compete with other forms of energy including natural gas, electricity, oil, propane and other alternative sources of energy. The principal competitive factors are price and, to a lesser extent, accessibility. Our natural gas distribution operations have several large-volume industrial customers that are able to use fuel oil as an alternative to natural gas. When oil prices decline, these interruptible customers may convert to oil to satisfy their fuel requirements, and our interruptible sales volumes may decline. Oil prices, as well as the prices of other fuels, fluctuate for a variety of reasons; therefore, future competitive conditions are not predictable. To address this uncertainty, we use flexible pricing arrangements on both the supply and sales sides of this business to compete with alternative fuel price fluctuations. As a result of the transmission operation s conversion to open access and Chesapeake s Florida natural gas distribution division s restructuring of its services, these businesses have shifted from providing bundled transportation and sales service to providing only transmission and contract storage services. Our electric distribution operation currently does not face substantial competition since the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

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

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

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

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

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(j) Inflation

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

(k) Marianna Franchise

On March 2, 2011, the City of Marianna, Florida filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement time-of-use (TOU) and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU s customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the City Commission of Marianna (Marianna Commission), which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU s property. On August 31, 2011, FPU advised the City of Marianna that it has no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU s property. At a hearing on January 10, 2012 the judge presiding over this case set plaintiff s motion for summary judgment for hearing on April 2, 2012. The court directed the parties to complete by March 23, 2012, depositions necessary for consideration at the summary judgment hearing. The court also set the case for trial commencing July 30, 2012. We anticipate that the case will be tried at that time. FPU intends to continue its vigorous defense of the lawsuit filed by the City of Marianna and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

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

Information concerning quantitative and qualitative disclosure about market risk is included in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Market Risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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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, 2011 and 2010, 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, 2011. 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 Chesapeake Utilities Corporation as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011 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), Chesapeake Utilities Corporation s internal control over financial reporting as of December 31, 2011 based on criteria established in *Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO)*, and our report dated March 7, 2012 expressed an unqualified opinion.

/s/ ParenteBeard LLC
ParenteBeard LLC

Malvern, Pennsylvania

March 7, 2012

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Consolidated Statements of Income

For the Years Ended December 31, *(in thousands, except shares and per share data)*	2011	2010	2009
Operating Revenues			
Regulated Energy	**$ 256,773**	$ 269,934	$ 139,099
Unregulated Energy	**149,586**	146,793	119,973
Other	**11,668**	10,819	9,713
Total operating revenues	**418,027**	427,546	268,785
Operating Expenses			
Regulated energy cost of sales	**128,111**	145,207	64,803
Unregulated energy and other cost of sales	**118,787**	116,098	95,467
Operations	**79,810**	77,227	52,184
Maintenance	**7,449**	7,484	3,430
Depreciation and amortization	**20,153**	18,536	11,588
Other taxes	**10,012**	11,064	7,577
Total operating expenses	**364,322**	375,616	235,049
Operating Income	**53,705**	51,930	33,736
Other income, net of other expenses	**906**	195	165
Interest charges	**9,000**	9,146	7,086
Income Before Income Taxes	**45,611**	42,979	26,815
Income taxes	**17,989**	16,923	10,918
Net Income	**$ 27,622**	$ 26,056	$ 15,897
Weighted Average Common Shares Outstanding:			
Basic	**9,555,799**	9,474,554	7,313,320
Diluted	**9,651,058**	9,582,374	7,440,201
Earnings Per Share of Common Stock:			
Basic	**$ 2.89**	$ 2.75	$ 2.17
Diluted	**$ 2.87**	$ 2.73	$ 2.15
Cash Dividends Declared Per Share of Common Stock	**$ 1.365**	$ 1.305	$ 1.250

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

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Consolidated Statements of Comprehensive Income

For the Years Ended December 31, *(in thousands)*	2011	2010	2009
Net Income	**$ 27,622**	$ 26,056	$ 15,897
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $432, $5 and $5, respectively	645	8	7
Net Gain (Loss), net of tax of ($1,164), ($541) and $794, respectively	(1,812)	(844)	1,217
Total other comprehensive income (loss)	**(1,167)**	(836)	1,224
Comprehensive Income	**$ 26,455**	$ 25,220	$ 17,121

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

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Consolidated Balance Sheets

Assets *(in thousands, except shares and per share data)*	**December 31, 2011**	**December 31, 2010**
Property, Plant and Equipment		
Regulated energy	**$ 532,616**	$ 500,689
Unregulated energy	**63,501**	61,313
Other	**19,988**	16,989
Total property, plant and equipment	**616,105**	578,991
Less: Accumulated depreciation and amortization	**(137,784)**	(121,628)
Plus: Construction work in progress	**9,383**	5,394
Net property, plant and equipment	**487,704**	462,757
Current Assets		
Cash and cash equivalents	**2,637**	1,643
Accounts receivable (less allowance for uncollectible accounts of $1,090 and $1,194, respectively)	**76,605**	88,074
Accrued revenue	**10,403**	14,978
Propane inventory, at average cost	**9,726**	8,876
Other inventory, at average cost	**4,785**	3,084
Regulatory assets	**1,846**	51
Storage gas prepayments	**5,003**	5,084
Income taxes receivable	**6,998**	6,748
Deferred income taxes	**2,712**	2,191
Prepaid expenses	**5,072**	4,613
Mark-to-market energy assets	**1,754**	1,642
Other current assets	**219**	289
Total current assets	**127,760**	137,273
Deferred Charges and Other Assets		
Goodwill	**4,090**	35,613
Other intangible assets, net	**3,127**	3,459
Investments, at fair value	**3,918**	3,992
Long-term receivables	**79**	155
Regulatory assets	**79,256**	23,884
Other deferred charges	**3,132**	3,860
Total deferred charges and other assets	**93,602**	70,963
Total Assets	**$ 709,066**	$ 670,993

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

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Consolidated Balance Sheets

Consolidated Balance Sheets

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**December 31, 2011**	**December 31, 2010**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000)	$ 4,656	$ 4,635
Additional paid-in capital	149,403	148,159
Retained earnings	91,248	76,805
Accumulated other comprehensive loss	(4,527)	(3,360)
Deferred compensation obligation	817	777
Treasury stock	(817)	(777)
Total stockholders equity	**240,780**	226,239
Long-term debt, net of current maturities	**110,285**	89,642
Total capitalization	**351,065**	315,881
Current Liabilities		
Current portion of long-term debt	**8,196**	9,216
Short-term borrowing	**34,707**	63,958
Accounts payable	**55,581**	65,541
Customer deposits and refunds	**30,918**	26,317
Accrued interest	**1,637**	1,789
Dividends payable	**3,300**	3,143
Accrued compensation	**6,932**	6,784
Regulatory liabilities	**6,653**	9,009
Mark-to-market energy liabilities	**1,496**	1,492
Other accrued liabilities	**8,079**	10,393
Total current liabilities	**157,499**	197,642
Deferred Credits and Other Liabilities		
Deferred income taxes	**115,624**	80,031
Deferred investment tax credits	**171**	243
Regulatory liabilities	**3,564**	3,734
Environmental liabilities	**9,492**	10,587
Other pension and benefit costs	**26,808**	18,199
Accrued asset removal cost - Regulatory liability	**36,584**	35,092
Other liabilities	**8,259**	9,584
Total deferred credits and other liabilities	**200,502**	157,470
Other commitments and contingencies (Note P and Q)		
Total Capitalization and Liabilities	**$ 709,066**	$ 670,993

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

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Consolidated Statements of Cash Flows

For the Years Ended December 31,	**2011**	**2010**	**2009**
(in thousands)			
Operating Activities			
Net Income	**$ 27,622**	$ 26,056	$ 15,897
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**20,153**	18,537	11,588
Depreciation and accretion included in other costs	**5,116**	4,364	2,789
Deferred income taxes, net	**17,714**	13,389	10,065
(Gain) loss on sale of assets	**(453)**	113	47
Unrealized (gain) loss on commodity contracts	**(41)**	(116)	1,606
Unrealized gain on investments	**(282)**	(181)	(212)
Employee benefits and compensation	**(723)**	(757)	1,217
Share based compensation	**1,450**	1,155	1,306
Other, net	**(50)**	(17)	(40)
Changes in assets and liabilities:			
Sale (purchase) of investments	**660**	(297)	(146)
Accounts receivable and accrued revenue	**14,979**	(20,467)	(13,652)
Propane inventory, storage gas and other inventory	**(2,484)**	151	2,597
Regulatory assets	**(324)**	1,677	(1,842)
Prepaid expenses and other current assets	**(345)**	1,157	(757)
Other deferred charges	**179**	(156)	(83)
Long-term receivables	**76**	286	191
Accounts payable and other accrued liabilities	**(13,612)**	15,853	10,185
Income taxes receivable	**(237)**	(3,761)	5,020
Accrued interest	**(152)**	(97)	66
Customer deposits and refunds	**5,096**	2,038	(75)
Accrued compensation	**19**	1,339	(2,066)
Regulatory liabilities	**(2,527)**	665	1,071
Other liabilities	**(713)**	187	1,074
Net cash provided by operating activities	**71,121**	61,118	45,846
Investing Activities			
Property, plant and equipment expenditures	**(47,037)**	(45,637)	(26,703)
Cash acquired in the merger, net of cash paid			359
Proceeds from sale of assets	**937**	113	53
(Purchases of) proceeds from investments	**(1,091)**	(3,108)	3,519
Environmental expenditures	**(645)**	(290)	(418)
Net cash used by investing activities	**(47,836)**	(48,922)	(23,190)
Financing Activities			
Common stock dividends	**(11,663)**	(11,013)	(7,957)
(Purchase) issuance of stock for Dividend Reinvestment Plan	**(1,244)**	568	392
Change in cash overdrafts due to outstanding checks	**91**	3,255	835
Net borrowing (repayment) under line of credit agreements	**(241)**	1,579	(3,812)
Other short-term borrowing	**(29,100)**	29,100	
Proceeds from issuance of long-term debt	**29,000**		
Repayment of long-term debt	**(9,134)**	(36,860)	(10,907)
Net cash used in financing activities	**(22,291)**	(13,371)	(21,449)

Net Increase (Decrease) in Cash and Cash Equivalents	**994**	(1,175)	1,207
Cash and Cash Equivalents Beginning of Period	**1,643**	2,818	1,611
Cash and Cash Equivalents End of Period	**$ 2,637**	$ 1,643	$ 2,818

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

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Consolidated Statements of Stockholders Equity

	xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxx
	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
Balances at December 31, 2008	**6,827,121**	**$3,323**	**$66,681**	**$56,817**	**$(3,748)**	**$1,549**	**$(1,549)**	**$123,073**
Net Income				15,897				15,897
Other comprehensive income					1,224			1,224
Dividend Reinvestment Plan	31,607	15	921					936
Retirement Savings Plan	32,375	16	966					982
Conversion of debentures	7,927	4	131					135
Share-based compensation (2) (3)	7,374	3	1,332					1,335
Deferred Compensation Plan (4)						(810)	810	
Purchase of treasury stock	(2,411)						(73)	(73)
Sale and distribution of treasury stock	2,411						73	73
Common stock issued in the merger	2,487,910	1,211	74,471					75,682
Dividends on share-based compensation				(104)				(104)
Cash dividends (5)				(9,379)				(9,379)
Balances at December 31, 2009	**9,394,314**	**4,572**	**144,502**	**63,231**	**(2,524)**	**739**	**(739)**	**209,781**
Net Income				26,056				26,056
Other comprehensive loss					(836)			(836)
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Share-based compensation (2) (3)	36,415	17	620					637
Tax benefit on share-based compensation			253					253
Deferred Compensation Plan (4)						38	(38)	
Purchase of treasury stock	(1,144)						(38)	(38)
Sale and distribution of treasury stock	1,144						38	38
Dividends on share-based compensation				(104)				(104)
Cash dividends (5)				(12,378)				(12,378)
Balances at December 31, 2010	**9,524,195**	**4,635**	**148,159**	**76,805**	**(3,360)**	**777**	**(777)**	**226,239**
Net Income				27,622				27,622
Other comprehensive loss					(1,167)			(1,167)
Dividend Reinvestment Plan			(22)					(22)
Retirement Savings Plan	2,002	1	79					80
Conversion of debentures	10,680	5	176					181
Share-based compensation (2) (3)	30,430	15	998					1,013
Tax benefit on share-based compensation			13					13
Deferred Compensation Plan (4)						40	(40)	
Purchase of treasury stock	(993)						(40)	(40)
Sale and distribution of treasury stock	993						40	40
Dividends on share-based compensation				(129)				(129)
Cash dividends (5)				(13,050)				(13,050)
Balances at December 31, 2011	**9,567,307**	**$4,656**	**$149,403**	**$91,248**	**$(4,527)**	**$817**	**$(817)**	**$240,780**

(1) Includes 30,597, 29,596 and 28,452, shares at December 31, 2011, 2010 and 2009, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For 2011 and 2010, the Company withheld 12,324 and 17,695 shares, respectively, for taxes. The Company did not issue any shares for the PIP in 2009.

(4)

In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in 2011 and 2010.

(5) Cash dividends per share for the periods ended December 31, 2011, 2010 and 2009 were $1.365, $1.305, and $1.250, respectively.

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

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Notes to the Consolidated Financial Statements

A. Summary of Accounting Policies

Nature of Business

Chesapeake, incorporated in 1947 in Delaware, is a diversified utility company engaged in regulated energy, unregulated energy and other unregulated businesses. Our regulated energy business delivers natural gas to approximately 122,000 customers located in central and southern Delaware, Maryland s eastern shore and Florida and electricity to approximately 31,000 customers in northeast and northwest Florida. Our regulated energy business also provides natural gas transmission service primarily through a 402-mile interstate pipeline from various points in Pennsylvania and northern Delaware to our natural gas distribution affiliates in Delaware and Maryland as well as to other utility and industrial customers in Pennsylvania, Delaware and the eastern shore of Maryland.

Our unregulated energy business includes natural gas marketing, propane distribution and propane wholesale marketing operations. The natural gas marketing operation sells natural gas supplies directly to commercial and industrial customers in Florida, Delaware and Maryland. Through our propane distribution operation, we distribute propane to approximately 49,000 customers in Delaware, the eastern shore of Maryland and Virginia, southeastern Pennsylvania and Florida. The propane wholesale marketing operation markets propane to wholesale customers including large independent oil and petrochemical companies, resellers and propane distribution companies in the southeastern United States.

We also engage in non-energy businesses, primarily through our advanced information services subsidiary, which provides information-technology-related business services and solutions for both enterprise and e-business applications.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Chesapeake and its wholly owned subsidiaries. As a result of the merger with FPU on October 28, 2009, FPU s financial position, results of operations and cash flows have been consolidated into our results from the effective date of the merger. 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 transactions have been eliminated in consolidation.

System of Accounts

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by the PSCs in their respective states with respect to their rates for service, maintenance of their accounting records and various other matters. Eastern Shore is an open access pipeline regulated by the FERC. Our financial statements are prepared in accordance with GAAP, which give appropriate recognition to the ratemaking and accounting practices and policies of the various regulatory commissions. Our unregulated energy and other unregulated businesses are not subject to regulation with respect to rates, service or maintenance of accounting records.

Reclassifications

We reclassified certain amounts in the consolidated statement of income for the year ended December 31, 2010 and in the consolidated statements of cash flows for the years ended December 31, 2010 and 2009, to conform to the current year s presentation. We also reclassified certain amounts in the consolidated balance sheet as of December 31, 2010, to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

Use of Estimates

Our financial statements are prepared in conformity with GAAP, which 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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Notes to the Consolidated Financial Statements

Property, Plant, Equipment and Depreciation

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Property, plant and equipment acquired in the merger were stated at fair value at the time of the merger. Costs include direct labor, materials and third-party construction contractor costs, allowance for capitalized interest 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. The provision for depreciation is computed using the straight-line method at rates that amortize the unrecovered cost of depreciable property over the estimated remaining useful life of the asset. Depreciation and amortization expenses for the regulated energy operations are provided at various annual rates, as approved by the regulators.

(In thousands)	**December 31, 2011**	December 31, 2010	**Useful Life [1]**
Plant in service			
Mains	**$ 278,274**	$ 259,672	27-62 years
Services utility	**72,341**	68,349	12-48 years
Compressor station equipment	**25,066**	24,952	42 years
Liquified petroleum gas equipment	**27,915**	27,623	5-31 years
Meters and meter installations	**35,006**	32,850	Unregulated energy 3-33 years, regulated energy 14-49 years
Measuring and regulating station equipment	**25,166**	22,332	14-54 years
Office furniture and equipment	**19,431**	15,796	Unregulated energy 4-7 years, regulated energy14-25 years
Transportation equipment	**18,441**	17,046	1-20 years
Structures and improvements	**16,553**	16,290	3-44 years [2]
Land and land rights	**16,577**	15,052	Not depreciable, except certain regulated assets
Propane bulk plants and tanks	**8,010**	7,967	12-40 years
Electric transmission lines and transformers	**31,937**	30,669	10-41 years
Poles and towers	**9,899**	9,259	21-40 years
Other equipment	**8,873**	9,189	Various
Various	**22,616**	21,945	Various
Total plant in service	**616,105**	578,991	
Plus construction work in progress	**9,383**	5,394	
Less accumulated depreciation	**(137,784)**	(121,628)	
Net property, plant and equipment	**$ 487,704**	$ 462,757	

(1) Certain immaterial account balances may fall outside this range.

The regulated operations compute depreciation in accordance with rates approved by either the state PSC or the FERC. These rates are based on depreciation studies and may change periodically upon receiving approval from the appropriate regulatory body. The depreciation rates shown above are based on the remaining useful lives of the assets at the time of the depreciation study, rather than the original lives of the assets. The depreciation rates are composite, straight-line rates applied to the average investment for each class of depreciable property and are adjusted for anticipated cost of removal less salvage value.

The non-regulated operations compute depreciation using the straight-line method over the estimated useful life of the asset.

(2) Includes buildings, structures used in connection with natural gas, electric and propane operations, improvements to those facilities and leasehold improvements.

Plant in service includes $1.4 million of assets owned by one of our natural gas transmission subsidiaries, which it uses to provide natural gas transmission service under a contract with a third party. This contract is accounted for as an operating lease due to exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and provides $264,000 in annual revenues for a term of 20 years. Accumulated depreciation for these assets total $218,000 at December 31, 2011.

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Notes to the Consolidated Financial Statements

In July 2011, we sold an Internet Protocol address asset to an unaffiliated entity for approximately $553,000. This particular Internet Protocol address was not used by us and did not have any net carrying value at the time of the sale. We recognized a non-operating pre-tax gain of $553,000 from this sale, which is included in other income in the accompanying consolidated statements of income.

In September 2011, FPU entered into an agreement with an unaffiliated entity to sell its office building located in West Palm Beach, Florida for $2.2 million. FPU also entered into a separate agreement to lease office space at a different location in West Palm Beach, which commenced in February 2012. The sale of FPU s West Palm Beach office building was finalized in February 2012. Some of the approximately 70 employees previously located in the West Palm Beach office building moved into the newly leased office space and the remaining employees moved into another nearby operations center, which FPU owns, in West Palm Beach. We treated the West Palm Beach office building as an asset held for sale and it was included in other property, plant and equipment at December 31, 2011 in the accompanying consolidated balance sheet. The West Palm Beach office building had a net carrying value of approximately $2.0 million at December 31, 2011. Since the sale price, less costs to consummate the sale, exceeded the net carrying value of the building, no impairment was recorded. As most of the West Palm Beach office building was considered a property within the regulated businesses, most of the gain resulting from the sale was charged to accumulated depreciation when the sale was completed in February 2012.

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 market value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

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.

Notes to the Consolidated Financial Statements

Regulatory Assets, Liabilities and Expenditures

We account for our regulated operations in accordance with ASC Topic 980, Regulated Operations. This Topic 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, 2011 and 2010, the regulated utility operations had recorded the following regulatory assets and liabilities on 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.

(in thousands)	**December 31, 2011**	December 31, 2010
Regulatory Assets		
Underrecovered purchased fuel costs [1]	**$ 911**	$
Income tax related amounts due from customers	**2,075**	1,897
Deferred post retirement benefits [2]	**15,640**	8,304
Deferred transaction and transition costs [3]	**1,600**	1,264
Deferred conversion and development costs [1]	**1,143**	2,069
Environmental regulatory assets and expenditures [4]	**6,131**	6,826
Acquisition adjustment [5]	**50,546**	764
Loss on reacquired debt [6]	**1,576**	1,668
Other	**1,480**	1,143
Total Regulatory Assets	**$ 81,102**	$ 23,935
Regulatory Liabilities		
Self insurance	**$ 1,010**	$ 1,265
Overrecovered purchased fuel costs [1]	**4,664**	8,159
Conservation cost recovery [1]	**12**	320
Rate Refund [7]	**1,250**	
Income tax related amounts due to customers	**22**	48
Storm reserve	**2,812**	2,682
Accrued asset removal cost	**36,584**	35,092
Other	**447**	269
Total Regulatory Liabilities	**$ 46,801**	$ 47,835

Notes to the Consolidated Financial Statements

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

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

(3) The Florida PSC approved the inclusion of FPU merger-related costs in our rate base and the recovery of those costs in rates. The balance at December 31, 2011 includes the gross-up of this regulatory asset for income tax because a portion of the costs is not tax-deductible.

(4) All of our environmental expenditures and liabilities have been approved by various PSC s for recovery. See Note P, Environmental Commitments and Contingencies, for additional information.

(5) The Florida PSC approved the inclusion of approximately $1.3 million of the premium paid by FPU for an acquisition of another natural gas utility in 2002 (prior to Chesapeake s acquisition of FPU) in its rate base and the recovery of it in rates. The Florida PSC also approved the inclusion of approximately $34.2 million in the premium paid by Chesapeake in its acquisition of FPU in the rate base and the recovery of it in rates. During 2011, we reclassified to a regulatory asset the portion of the goodwill related to the FPU acquisition, which was approved for recovery in future rates, along with the gross-up for income taxes. See Note B, Acquisitions, for additional information.

(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) Eastern Shore refunded this amount to customers in February 2012 as a result of the rate case settlement. See Note O, Rates and Other Regulatory Activities, for additional information.

We monitor our regulatory and competitive environment 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.

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 H, Goodwill and Other Intangible Assets, for additional discussion of this subject.

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 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. Management annually reviews 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 and the expected returns on plan assets are the assumptions 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.

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Notes to the Consolidated Financial Statements

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 the 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 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 assumed 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.

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 discount rate could change our pension and postretirement costs by approximately $34,000. A 0.25 percent change in the rate of return could change our pension cost by approximately $108,000 and will not have an impact on the postretirement and supplemental pension plans because these plans are not funded.

Income Taxes and Investment Tax Credit Adjustments

Deferred tax assets and liabilities are recorded for the tax effect of temporary differences between the financial statement bases and tax bases of assets and liabilities and are measured using the enacted tax rates in effect in the years in which the differences are expected to reverse. The portions of our deferred tax liabilities applicable to regulated energy operations, which have not been reflected in current service rates, represent income taxes recoverable through future rates. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such 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.

Financial Instruments

Xeron, our propane wholesale marketing subsidiary, 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. The changes in market price are recognized as gains or losses in revenues on the consolidated statements of income in the period of change. Trading liabilities are recorded as mark-to-market energy liabilities. Trading assets are recorded as mark-to-market energy assets.

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.

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Notes to the Consolidated Financial Statements

Our propane distribution operation may enter into derivative transactions, such as swaps and puts, in order to mitigate the impact of wholesale price fluctuations on its inventory valuation. These transactions may be designated as fair value hedges if they meet all of the accounting requirements pursuant to ASC 815 and we elect to designate the instruments as fair value hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap or put, 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. The ineffective portion of the gain or loss is recorded in earnings. If the instrument is not designated as a fair value hedge or does not meet the accounting requirements of a fair value hedge, it is recorded at fair value with the gain or loss being recorded in earnings.

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 chart.

For the Years Ended December 31, *(in thousands, except shares and per share data)*	**2011**	2010	2009
Calculation of Basic Earnings Per Share:			
Net Income	**$ 27,622**	$ 26,056	$ 15,897
Weighted average shares outstanding	**9,555,799**	9,474,554	7,313,320
Basic Earnings Per Share	**$ 2.89**	$ 2.75	$ 2.17
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	**$ 27,622**	$ 26,056	$ 15,897
Effect of 8.25% Convertible debentures	**61**	73	79
Adjusted numerator Diluted	**$ 27,683**	$ 26,129	$ 15,976
Reconciliation of Denominator:			
Weighted shares outstanding Basic	**9,555,799**	9,474,554	7,313,320
Effect of dilutive securities:			
Share-based Compensation	23,792	22,550	34,229
8.25% Convertible debentures	71,467	85,270	92,652
Adjusted denominator Diluted	9,651,058	9,582,374	7,440,201
Diluted Earnings Per Share	**$ 2.87**	$ 2.73	$ 2.15

In 2009, common stock issued in connection with the FPU merger (See Note B, Acquisitions, to the Consolidated Financial Statements) was outstanding for only two months (from the merger closing on October 28, 2009 to December 31, 2009).

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSCs in the states 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.

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Notes to the Consolidated Financial Statements

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. In connection with this accrual, we must estimate the amounts of natural gas and electricity that have been delivered to our systems but have not been accounted for (commonly known as unaccounted for gas and electricity). 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 our accounting periods.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in our consolidated statement of income. For propane distribution customers without meters and advanced information services customers, 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 FPU natural gas operation and our electric distribution operation in Florida has a purchased fuel cost recovery mechanism. This mechanism provides 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 purchased 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 provides only unbundled delivery service.

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 we provide for our regulated and unregulated energy segments. 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 the direct cost of labor for our advanced information services operation.

Operations and Maintenance Expenses

Operations and maintenance expenses are costs associated with the operation and maintenance of our regulated and unregulated operations. Major cost components include operation 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.

Depreciation and Accretion Included in Operations Expenses

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 expenses consist 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, 2011, 2010 and 2009, \$5.1 million, \$4.4 million and \$2.8 million, respectively, of depreciation and accretion were reported in operations expenses.

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Notes to the Consolidated Financial Statements

Allowance for Doubtful Accounts

An allowance for doubtful accounts is recorded against amounts due to reduce the net receivables balance to the amount we reasonably expect to collect based upon our collections experiences and management s assessment of our 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.

Subsequent Events

We have assessed and reported on subsequent events through the date of issuance of these Consolidated Financial Statements.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Amendments Yet to be Adopted by the Company

In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. Amendments in the ASU do not extend the use of fair value accounting but provide guidance on how it should be applied where its use is already required or permitted by other standards within International Financial Accounting Standards (IFRS) or U.S. GAAP. ASU 2011-04 supersedes most of the guidance in Topic 820, although many of the changes are clarifications of existing guidance or wording changes to align with IFRS. Certain amendments in ASU 2011-04 change a particular principle or requirement for measuring fair value or disclosing information about fair value measurements. The amendments in ASU 2011-04 are effective for public entities for interim and annual periods beginning after December 15, 2011, and should be applied prospectively. Early adoption is not permitted for public entities. We expect the adoption of ASU 2011-04 to have no material impact on our financial position and results of operations.

In September 2011, the FASB issued ASU 2011-08, Intangibles Goodwill and Other (Topic 350) Testing Goodwill for Impairment. ASU 2011-08 allows an entity to assess qualitatively whether it is necessary to perform step one of the two-step annual goodwill impairment test. Step one would be required if it is more-likely-than-not that a reporting unit s fair value is less than its carrying amount. This is different than previous guidance, which required entities to perform step one of the test, at least annually, by comparing the fair value of a reporting unit to its carrying amount. An entity may elect to bypass the qualitative assessment and proceed directly to step one, for any reporting unit, in any period. ASU 2011-08 does not change the guidance on when to test goodwill for impairment. The amendments in ASU 2011-08 are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We expect the adoption of ASU 2011-08 to have no material impact on our financial position and results of operations.

Notes to the Consolidated Financial Statements

Other Accounting Amendments Adopted by the Company in 2011

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income. ASU 2011-05 amends the guidance in Topic 220, Comprehensive Income, by eliminating the option to present components of other comprehensive income (OCI) in the statement of stockholders equity. Instead, the new guidance now requires entities to present all non-owner changes in stockholders equity either as a single continuous statement of comprehensive income or as two separate but consecutive statements of income and comprehensive income. The components of OCI have not changed nor has the guidance on when OCI items are reclassified to net income. Similarly, ASU 2011-05 does not change the guidance to disclose OCI components gross or net of the effect of income taxes, provided that the tax effects are presented on the face of the statement in which OCI is presented, or disclosed in the notes to the financial statements. For public entities, the amendments in ASU 2011-05 are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2011 with early adoption permitted. In December 2011, the FASB indefinitely deferred provisions of ASU 2011-05 that require entities to present all reclassification adjustments from OCI to net income on the face of the statement of comprehensive income. On December 31, 2011, we voluntarily adopted ASU 2011-05 early, except for the provisions deferred indefinitely. As a result of our early adoption of ASU 2011-05, we are now presenting a separate statement of comprehensive income, following the statement of income. The change is for presentation only, and the early adoption of ASU 2011-05 did not impact our financial position, results of operations or cash flows.

B. Acquisitions

FPU

On October 28, 2009, we completed a merger with FPU, pursuant to which FPU became a wholly owned subsidiary of Chesapeake. The merger was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer for accounting purposes. In consummating the merger, we issued 2,487,910 shares of Chesapeake common stock at a price per share of $30.42 in exchange for all outstanding common stock of FPU. We also paid approximately $16,000 in lieu of issuing fractional shares in the exchange. There was no contingent consideration in the merger. The total value of consideration transferred by Chesapeake in the merger was approximately $75.7 million. The assets acquired and liabilities assumed in the merger were recorded at their respective fair values at the completion of the merger. For certain assets acquired and liabilities assumed, such as pension and post-retirement benefit obligations, income taxes and contingencies without readily determinable fair values, for which GAAP provides specific exception to the fair value recognition and measurement, we applied other specified GAAP or accounting treatment as appropriate. Goodwill from the merger was $34.2 million. Pursuant to the approval by the Florida PSC in January 2012 to include the $34.2 million premium paid in this merger in the rate base and amortize it over a 30-year period beginning in November 2009 (see Note O, Rates and Other Regulatory Activities), we reclassified to a regulatory asset at December 31, 2011, $31.7 million of the goodwill, which represents the portion of the goodwill allowed to be recovered in future rates after the effective date of the Florida PSC order.

The acquisition method of accounting requires acquisition-related costs to be expensed in the period, in which those costs are incurred, rather than including them as a component of consideration transferred. As we intended to seek recovery in future rates in Florida of the merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining the proper accounting treatment for those costs. We deferred approximately $1.3 million as a regulatory asset, which represented our best estimate of the costs we expected to be permitted to recover when we completed the appropriate rate proceedings. In January 2012, the Florida PSC approved the recovery of the $1.3 million deferred merger-related costs in future rates (see Note O, Rates and Other Regulatory Activities).

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Virginia LP Gas

On February 4, 2010, Sharp, our propane distribution subsidiary, purchased the operating assets of Virginia LP Gas, Inc. (Virginia LP), a propane distributor serving approximately 1,000 retail customers in Northampton and Accomack Counties in Virginia. The total consideration for the purchase was $600,000, $300,000 of which was paid at the closing and the remaining $300,000 is to be paid over 60 months. Based on our valuation, we allocated $188,000 of the purchase price to intangible assets, which consist of customer lists and non-compete agreements. These intangible assets are being amortized over a seven-year period. There was no goodwill recorded in connection with this acquisition. The revenue and net income from this acquisition, which were included in our consolidated statement of income for the year ended December 31, 2010, were not material.

Indiantown Gas Company

On August 9, 2010, FPU purchased the natural gas operating assets of IGC, which provides natural gas distribution services to approximately 700 customers including two large industrial customers in Indiantown, Florida. FPU paid approximately $1.2 million for these assets. FPU recorded $742,000 in goodwill in connection with this acquisition, all of which is deductible for income tax purposes. There was no intangible asset recorded in connection with this acquisition. The revenue and net income from this acquisition, which were included in our consolidated statement of income for the year ended December 31, 2010, were not material.

Crescent Propane

On December 12, 2011, Flo-Gas Corporation, the propane distribution subsidiary of FPU, purchased the operating assets of Crescent Propane, Inc. (Crescent) for approximately $790,000. These assets are used to provide propane distribution services to approximately 800 customers in north central Florida. In connection with this acquisition, we recorded $200,000 in goodwill, all of which is deductible for income tax purposes. There was no intangible asset recorded in connection with this acquisition. The revenue and net income from this acquisition, which were included in our consolidated statement of income for the year ended December 31, 2011, were not material.

C. 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 of three operating segments:

Regulated Energy. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the PSCs having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.

Unregulated Energy. The unregulated energy segment includes natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and services.

Other. The Other segment consists primarily of the advanced information services subsidiary, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

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Notes to the Consolidated Financial Statements

The following table presents information about our reportable segments.

For the Years Ended December 31, (in thousands)	2011	2010	2009
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 255,405**	$ 268,830	$ 137,847
Unregulated Energy	**149,586**	146,430	119,719
Other	**13,036**	12,286	11,219
Total operating revenues, unaffiliated customers	**$ 418,027**	$ 427,546	$ 268,785
Intersegment Revenues [1]			
Regulated Energy	**$ 1,368**	$ 1,104	$ 1,252
Unregulated Energy		363	254
Other	**793**	856	779
Total intersegment revenues	**$ 2,161**	$ 2,323	$ 2,285
Operating Income			
Regulated Energy	**$ 44,204**	$ 43,509	$ 26,900
Unregulated Energy	**9,326**	7,908	8,158
Other	**175**	513	(1,322)
Operating Income	**53,705**	51,930	33,736
Other income	**906**	195	165
Interest charges	**9,000**	9,146	7,086
Income taxes	**17,989**	16,923	10,918
Net income from continuing operations	**$ 27,622**	$ 26,056	$ 15,897
Depreciation and Amortization			
Regulated Energy	**$ 16,650**	$ 14,815	$ 8,866
Unregulated Energy	**3,090**	3,433	2,415
Other and eliminations	**413**	288	307
Total depreciation and amortization	**$ 20,153**	$ 18,536	$ 11,588
Capital Expenditures			
Regulated Energy	**$ 37,104**	$ 41,898	$ 22,917
Unregulated Energy	**2,432**	2,764	1,873
Other	**4,895**	2,293	1,504
Total capital expenditures	**$ 44,431**	$ 46,955	$ 26,294

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

At December 31,	2011	2010
Identifiable Assets		
Regulated Energy	**$ 569,389**	$ 520,192
Unregulated Energy	**104,090**	113,039
Other	**35,587**	37,762
Total identifiable assets	**$ 709,066**	$ 670,993

Our operations are almost entirely domestic. Our advanced information services subsidiary, BravePoint, has infrequent transactions with foreign companies, located primarily in Canada. These transactions, which are denominated and paid in U.S. dollars, are immaterial to the consolidated revenues.

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D. Supplemental Cash Flow Disclosures

Cash paid for interest and income taxes during the years ended December 31, 2011, 2010 and 2009 were as follows:

For the Years Ended December 31, *(in thousands)*	2011	2010	2009
Cash paid for interest	**$ 7,746**	$ 8,134	$ 6,703
Cash paid for income taxes	**$ 2,327**	$ 10,168	$ 1,111

Non-cash investing and financing activities during the years ended December 31, 2011, 2010, and 2009 were as follows:

For the Years Ended December 31, *(in thousands)*	2011	2010	2009
Capital property and equipment acquired on account, but not paid as of December 31	**$ 938**	$ 1,064	$ 1,151
Merger/acquisitions	**$**	$ 300	$ 75,682
Retirement Savings Plan	**$ 80**	$ 902	$ 982
Dividend Reinvestment Plan	**$**	$ 1,182	$ 692
Conversion of Debentures	**$ 181**	$ 202	$ 135
Performance Incentive Plan	**$ 280**	$ 719	$
Director Stock Compensation Plan	**$ 456**	$ 297	$ 214

E. Derivative Instruments

Xeron, our propane wholesale and marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. As of December 31, 2011, we had the following outstanding trading contracts which we accounted for as derivatives:

At December 31, 2011	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	12,075,000	$1.3100	$1.6063	$ 1.4785
Purchase	11,928,000	$1.3050	$1.6000	$ 1.4630

Estimated market prices and weighted average contract prices are in dollars per gallon.

All contracts expire by the end of the first quarter of 2012.

In August 2011, Sharp, our Delmarva propane distribution subsidiary, entered into a put option to protect against the decline 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. This put option is exercised if the propane prices fall below the strike price of $1.445 per gallon in January through March of 2012, and we will receive the difference between the market price and the strike price during those months. We paid $91,000 to purchase the put option. We account for this put option as a fair value hedge. As of December 31, 2011, the put option had a fair value of $68,000. The change in the fair value of the put option effectively reduced our propane inventory balance. There was no ineffective portion of this fair value hedge in 2011.

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Notes to the Consolidated Financial Statements

In October 2010, Sharp entered into put options to protect against the decline in propane prices and related potential inventory losses associated with 1,470,000 gallons purchased for the propane price cap program in the upcoming heating season. This put option would be exercised if the propane prices fell below the strike prices of $1.251 per gallon and $1.230 per gallon in January and February of 2011, respectively, at which point we would have received the difference between the market price and the strike price during those months. We paid $168,000 to purchase the put option. Although the put option met the accounting requirements for fair value hedge, we elected not to designate it as a fair value hedge and accounted for it on a mark-to-market basis. As of December 31, 2010, the put option had no fair value. The change in the fair value of the put option reduced our earnings in 2010.

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, 2011 and 2010, are the following:

	Asset Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**December 31, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 1,686**	$ 1,642
Put option	Mark-to-market energy assets		
Derivatives designated as fair value hedges			
Put option	Mark-to-market energy assets	**68**	
Total asset derivatives		**$ 1,754**	$ 1,642

	Liability Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**December 31, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 1,496**	$ 1,492
Total liability derivatives		**$ 1,496**	$ 1,492

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Notes to the Consolidated Financial Statements

The effects of gains and losses from derivative instruments are the following:

	Location of Gain	Amount of Gain (Loss) on Derivatives: For the Years Ended December 31,		
(in thousands)	**(Loss) on Derivatives**	**2011**	**2010**	**2009**
Derivatives designated as fair value hedges:				
Propane swap agreement [1]	Cost of Sales	**$**	$	$ (42)
Put Option [2]	Propane Inventory	**(23)**		
Derivatives not designated as hedging instruments:				
Put Option	Cost of Sales		(168)	
Put Option [3]	Revenue			(41)
Unrealized gain (loss) on forward contracts	Revenue	**41**	284	(1,565)
Total		**$ 18**	$ 116	$ (1,648)

(1) Our propane distribution operation entered into a propane swap agreement to protect it from the impact that wholesale propane price increases would have on the propane price cap plan that was offered to customers. We terminated this swap agreement in January 2009.

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

(3) We purchased a put option for the propane price cap plan in September 2009. The put option, which expired on March 31, 2010, had a fair value of $0 at December 31, 2009.

The effects of trading activities on the Consolidated Statements of Income are the following:

	Location of Gain	Amount of Trading Revenue For the Years Ended December 31,		
(in thousands)	**(Loss) on Derivatives**	**2011**	**2010**	**2009**
Realized gain on forward contracts/put option	Revenue	**$ 2,215**	$ 1,540	$ 3,830
Unrealized gain (loss) on forward contracts	Revenue	**41**	284	(1,565)
Total		**$ 2,256**	$ 1,824	$ 2,265

F. 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).

Notes to the Consolidated Financial Statements

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2011:

		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 - equity securities	$ 2,224	$ 2,224	$	$
Investments - other [1]	$ 1,734	$ 1,734	$	$
Mark-to-market energy assets, including put option	$ 1,754	$	$ 1,754	$
Liabilities:				
Mark-to-market energy liabilities	$ 1,496	$	$ 1,496	$

[1] The current portion of this investment ($40) is included in other current assets in the accompanying consolidated balance sheets.

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2010:

		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 - equity securities	$ 1,515	$ 1,515	$	$
Investments - other [1]	$ 2,521	$ 2,521	$	$
Mark-to-market energy assets, including put option	$ 1,642	$	$ 1,642	$
Liabilities:				
Mark-to-market energy liabilities	$ 1,492	$	$ 1,492	$

[1] The current portion of this investment ($44) is included in other current assets in the accompanying consolidated balance sheets.

Notes to the Consolidated Financial Statements

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of December 31, 2011 and 2010:

Level 1 Fair Value Measurements:

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

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

Level 2 Fair Value Measurements:

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

Propane put option The fair value of the propane put option is valued using market transactions for similar assets and liabilities in either the listed or OTC markets.

At December 31, 2011, 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 carrying value of these financial assets and liabilities approximates fair value due to their short maturities and because interest rates approximate current market rates for short-term debt.

At December 31, 2011, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $118.5 million, compared to a fair value of $142.3 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, and risk profile. The valuation technique used to estimate the fair value of long-term debt would be considered Level 3 measurement.

G. Investments

The investment balance at December 31, 2011, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan; (b) a Rabbi Trust related to a stay bonus agreement with a former executive; and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. We recorded $282,000 for an unrealized gain, net of other expenses, in other income in the consolidated statements of income. We also have an associated liability that is recorded and adjusted each month for the gains and losses incurred by the Rabbi Trusts. At December 31, 2011 and 2010, total investments had a fair value of $4.0 million.

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H. Goodwill and Other Intangible Assets

The carrying value of goodwill as of December 31, 2011 and 2010 was as follows:

(in thousands)	December 31, 2011	December 31, 2010
Regulated Energy	**$ 3,216**	$ 34,939
Unregulated Energy	**874**	674
Total	**$ 4,090**	$ 35,613

Goodwill in the regulated energy segment is comprised of approximately $2.5 million from the FPU merger and $746,000 from the purchase of operating assets from IGC. Goodwill in the unregulated energy segment is comprised of $200,000 from the purchase of the operating assets from Crescent on December 12, 2011, and $674,000 related to the premium paid by Sharp in its acquisitions in the late 1980s and 1990s.

As discussed in Note B, Acquisitions, we reclassified to a regulatory asset during 2011, $31.7 million of the $34.2 million goodwill previously recorded in connection with the FPU acquisition.

We test for impairment of goodwill at least annually. The impairment testing for 2011 and 2010 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2011 and 2010 are as follows:

	December 31, 2011		December 31, 2010	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer list	**$ 3,500**	**$ 631**	$ 3,500	$ 340
Other	**566**	**308**	566	267
	$ 4,066	**$ 939**	$ 4,066	$ 607

The customer list is an intangible asset which was acquired in the FPU merger in October 2009 and is being amortized over a 12-year period. Other intangible assets include customer lists and a non-compete agreement acquired in the purchase of the operating assets of Virginia LP in February 2010 and customer lists and acquisition costs from our acquisitions in the late 1980s and 1990s. These intangible assets are being amortized over a period ranging from seven to 40 years.

For the years ended December 31, 2011, 2010 and 2009, amortization expense of intangible assets was $332,000, $679,000 and $232,000, respectively. Amortization expense of intangible assets for 2012 to 2016 is: $329,000 for 2012 and, $325,000 for 2013-2016.

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I. 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. FPU has been included in our consolidated federal return since the completion of the merger on October 28, 2009. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. FPU continues to file a separate state income tax return in Florida.

During 2011, the Internal Revenue Service (IRS) performed its examination of FPU s consolidated federal returns for 2008 and for 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 tax return) and proposed a disallowance of approximately $135,000 and $256,000, respectively, of the environmental expenditure deductions taken by FPU related to one of the environmental remediation sites. We disagreed with the IRS finding and filed an appeal, which is currently underway. The IRS finding is based on the failure of FPU to follow a technical requirement to label these environmental expenditures in a specific way on the returns. The IRS has granted relief in the past to other companies in a similar situation, which allowed those companies to correctly label such expenditures. We have requested this relief with the IRS and upon receiving this relief, we believe that those deductions will likely be sustained during the appeal process. Accordingly, we did not record any accrual as of December 31, 2011, related to the examination by the IRS of the FPU returns.

In January 2012, the IRS informed us that Chesapeake s consolidated federal return for 2009 has been selected for examination. The IRS previously examined our 2005 and 2006 consolidated federal returns, which resulted in a total adjustment of $27,000 in our tax liability. The IRS is currently performing its examination and we cannot predict the outcome at this time. We did not record any accrual for uncertain income tax positions in 2009, 2010 and 2011.

We generated net operating losses of $1.5 million in 2011, for federal income tax purposes, primarily from increased book-to-tax timing differences authorized by The Tax Relief Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which allowed bonus depreciation for certain assets. The federal net operating losses are available to offset future taxable income and will expire in 2026. We had previously generated net operating losses in 2008 for federal income tax purposes, which were carried forward to fully offset our taxable income in 2009 and partially offset our taxable income in 2010. None of the federal net operating losses from 2008 remained at December 31, 2010. We also had tax net operating losses in various states totaling $19.0 million as of December 31, 2011, almost all of which will expire in 2028. We have recorded a deferred tax asset of $991,000 and $1.3 million related to the federal and state net operating loss carry-forwards at December 31, 2011 and 2010, respectively. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will all be fully utilized.

The following tables provide: (a) the components of income tax expense in 2011, 2010 and 2009; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2011, 2010 and 2009; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2011 and 2010.

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For the Years Ended December 31, *(in thousands)*	**2011**	**2010**	**2009**
Current Income Tax Expense			
Federal	**$**	$ 1,566	$ 0
State	**742**	2,116	878
Investment tax credit adjustments, net	**(73)**	(91)	(69)
Total current income tax expense	**669**	3,591	809
Deferred Income Tax Expense [1]			
Property, plant and equipment	**16,885**	16,964	7,098
Deferred gas costs	**591**	(2,505)	(786)
Pensions and other employee benefits	**786**	(402)	(612)
Amortization of intangibles	**17**	(211)	5
Environmental expenditures	**(65)**	32	7
Net operating loss carryforwards	**(1,000)**	99	4,106
Merger related costs		(13)	967
Reserve for insurance deductibles	**18**	(419)	518
Other	**88**	(213)	(1,194)
Total deferred income tax expense	**17,320**	13,332	10,109
Total Income Tax Expense	**$ 17,989**	$ 16,923	$ 10,918
Reconciliation of Effective Income Tax Rates			
Continuing Operations			
Federal income tax expense [2]	**$ 16,146**	$ 15,053	$ 9,171
State income taxes, net of federal benefit	**2,216**	2,083	1,490
Merger related costs		70	299
ESOP dividend deduction	**(236)**	(266)	(213)
Other	**(137)**	(17)	171
Total income tax expense	**$ 17,989**	$ 16,923	$ 10,918
Effective income tax rate	**39.44%**	39.38%	40.72%

At December 31, *(in thousands)*	**2011**	**2010**
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	**$ 123,940**	$ 89,544
Deferred gas costs	**301**	
Loss on reacquired debt	**608**	643
Other	**3,872**	2,891
Total deferred income tax liabilities	**128,721**	93,078
Deferred income tax assets:		
Pension and other employee benefits	**7,796**	7,849
Environmental costs	**1,835**	1,770
Net operating loss carryforwards	**2,401**	1,300
Self insurance	**452**	419

Storm reserve liability	**1,085**	1,034
Other	**2,240**	2,866
Total deferred income tax assets	**15,809**	15,238
Deferred Income Taxes Per Consolidated Balance Sheet	**$ 112,912**	$ 77,840

(1) Includes $2,280,000, $1,963,000 and $1,588,000 of deferred state income taxes for the years 2011, 2010 and 2009, respectively.
(2) Federal income taxes were recorded at 35% for each year represented.

Notes to the Consolidated Financial Statements

J. Long-term Debt

Our outstanding long-term debt is as shown below.

(in thousands)	December 31, 2011	December 31, 2010
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$ 6,348**	$ 7,248
10.03% bond, due May 1, 2018	**3,492**	3,986
9.08% bond, due June 1, 2022	**7,958**	7,950
Uncollateralized senior notes:		
6.85% note, due January 1, 2012		1,000
7.83% note, due January 1, 2015	**6,000**	8,000
6.64% note, due October 31, 2017	**16,363**	19,091
5.50% note, due October 12, 2020	**18,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
5.68% note, due June 30, 2026	**29,000**	
Convertible debentures:		
8.25% due March 1, 2014	**1,134**	1,318
Promissory note	**186**	265
Total long-term debt	**118,481**	98,858
Less: current maturities	**(8,196)**	(9,216)
Total long-term debt, net of current maturities	**$ 110,285**	$ 89,642

Annual maturities of consolidated long-term debt are as follows: $8,196 for 2012; $8,196 for 2013;

$11,196 for 2014; $10,275 for 2015 and $80,683 thereafter.

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. The 9.57 percent bond and 10.03 percent bond require annual sinking fund payments of $909,000 and $500,000, respectively.

Uncollateralized Senior Notes

On June 23, 2011, we issued $29.0 million of 5.68 percent unsecured senior notes to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement we entered into with them on June 29, 2010. These notes have similar covenants and default provisions as Chesapeake s existing senior notes, and they require annual principal payments of $2.9 million beginning in the sixth year after the issuance. We used the proceeds to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds. These redemptions occurred in January 2010 and were previously financed by Chesapeake s short-term loan facilities. Under the same agreement, we may issue an additional $7.0 million of unsecured senior notes prior to May 3, 2013, at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance. These notes, if issued, will have similar covenants and default provisions as the senior notes issued in June 2011.

Convertible Debentures

The convertible debentures may be converted, at the option of the holder, into shares of our common stock at a conversion price of $17.01 per share. During 2011 and 2010, debentures totaling $181,000 and $202,000, respectively, were converted to stock. The debentures are also redeemable for cash at the option of the holder, subject to an annual non-cumulative maximum limitation of $200,000. In 2011, debentures totaling $2,000 were redeemed for cash. In 2010, no debentures were redeemed for cash. At our option, the debentures may be redeemed at stated amounts.

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Debt Covenants

Indentures to our long-term debt contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40 percent of total capitalization, and the fixed charge coverage ratio must be at least 1.2 times. In connection with the merger, the uncollateralized senior notes were amended to include an additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth by October 2011. 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, 2011, we are in compliance with all of our debt covenants. With the redemption of FPU s 6.85 percent and 4.90 percent secured first mortgage bonds in January 2010, the additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth was met.

Each of Chesapeake s uncollateralized senior notes contains a Restricted Payments covenant as defined in the note agreements. The most restrictive covenants of this type are included within the 7.83 percent Unsecured Senior Notes, due January 1, 2015. 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 our consolidated net income accrued on and after January 1, 2001. As of December 31, 2011, the cumulative consolidated net income base was $156.5 million, offset by Restricted Payments of $89.2 million, leaving $67.3 million of cumulative net income free of restrictions.

Each series of FPU s first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which provides 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, 2011, FPU s cumulative net income base was $74.0 million, offset by restricted payments of $37.6 million, leaving $36.4 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 $57.2 million of the net assets of our consolidated subsidiaries to be restricted at December 31, 2011. This represents approximately 24 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 consolidated subsidiaries for the purposes of determining the disclosure of parent-only financial statements.

K. Short-term Borrowing

At December 31, 2011 and 2010, we had $34.7 million and $64.0 million, respectively, of short-term borrowings outstanding. The annual weighted average interest rates on our short-term borrowings were 1.57 percent and 1.77 percent for 2011 and 2010, respectively. We incurred commitment fees of $85,000 and $86,000 in 2011 and 2010, respectively.

The outstanding short-term borrowings at December 31, 2011 were composed of $30.5 million in borrowings from bank lines of credit and $4.2 million in book overdrafts, which if presented would be funded through the bank lines of credit. The outstanding short-term borrowings at December 31, 2010 included $30.8 million in borrowings from the bank lines of credit, $29.1 million in borrowings from a term loan, which matured in June 2011, and $4.1 million in book overdrafts.

As of December 31, 2011, we had four unsecured bank lines of credit with two financial institutions, totaling $100.0 million, none of which requires compensating balances. These bank lines are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures. We maintain both committed and uncommitted credit facilities. 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 $85.0 million of short-term debt, as required, from these short-term lines of credit.

Committed credit facilities

As of December 31, 2011, we had two committed revolving credit facilities totaling $60.0 million. The first facility is an unsecured $30.0 million revolving line of credit that bears interest at the respective LIBOR rate, plus 1.25 percent per annum. At December 31, 2011, there was $2.0 million available under this credit facility.

The second facility is a $30.0 million committed revolving line of credit that bears interest at a base rate plus 1.25 percent, if requested and advanced on the same day, or LIBOR for the applicable period plus 1.25 percent if requested three days prior to the advance date. At

December 31, 2011, there was $27.5 million available under this credit facility.

Notes to the Consolidated Financial Statements

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.

Uncommitted credit facilities

As of December 31, 2011, we had two uncommitted line-of-credit facilities totaling $40.0 million. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks.

The first facility is an uncommitted $20.0 million line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. At December 31, 2011, the entire borrowing capacity of $20.0 million was available under this credit facility.

The second facility is a $20.0 million uncommitted line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. We have issued $4.9 million in letters of credit under this credit facility. There have been no draws on these letters of credit as of December 31, 2011. 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. At December 31, 2011, there was $15.1 million available under this credit facility, which was reduced by $4.9 million for letters of credit issued.

In addition to the four unsecured bank lines of credit, we entered into a new term loan for $29.1 million with an existing lender in March 2010 to temporarily finance the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds. On June 23, 2011, we issued $29.0 million of 5.68 percent Chesapeake unsecured senior notes to repay the new short-term credit facility and permanently finance the FPU first mortgage bonds.

L. Lease Obligations

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases for 2011, 2010 and 2009 was $1.2 million, $1.1 million and $997,000, respectively. Future minimum payments under our current lease agreements for the years 2012 through 2016 are $1.1 million, $866,000, $860,000, $733,000 and $733,000, respectively; and approximately $2.7 million thereafter, with an aggregate total of approximately $7.0 million.

M. Employee Benefit Plans

Retirement Plans

We sponsor a defined benefit pension plan (Chesapeake Pension Plan), an unfunded pension supplemental executive retirement plan (Chesapeake SERP), and an unfunded postretirement health care and life insurance plan (Chesapeake Postretirement Plan). As a result of the merger with FPU, we now also sponsor and maintain a separate defined benefit pension plan for FPU (FPU Pension Plan) and a separate unfunded postretirement medical plan for FPU (FPU Medical Plan).

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.

Notes to the Consolidated Financial Statements

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, 2011:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ (6)	$	$ 65	$ (1,063)	$	$ (1,004)
Net loss	4,337	10,697	712	1,178	1,277	18,201
Total	$ 4,331	$ 10,697	$ 777	$ 115	$ 1,277	$ 17,197
Accumulated other comprehesive loss pre-tax [(1)]	$ 4,331	$ 2,032	$ 777	$ 115	$ 243	$ 7,498
Regulatory asset post merger		8,665			1,034	9,699
Subtotal	4,331	10,697	777	115	1,277	17,197
Regulatory asset pre-merger		5,870			70	5,940
Total unrecognized cost	$ 4,331	$ 16,567	$ 777	$ 115	$ 1,347	$ 23,137

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2011 is net of income tax benefits of $3.0 million.

The pre-merger regulatory asset of $5.9 million at December 31, 2011 represents the portion attributable to FPU s regulated energy operations of the changes in the funded status in the FPU Pension Plan and FPU Medical Plan that occurred but were not recognized, as part of the net periodic benefit costs prior to the merger. This portion was deferred as a regulatory asset prior to the merger by FPU pursuant to a previous order by the Florida PSC and continues to be amortized over the remaining service period of the participants at the time of the merger.

During the second half of 2011, we experienced a significant decline in interest and other corporate bond rates, and as a result, we used lower discount rates for our pension and other postretirement plans at December 31, 2011 to estimate the benefit obligations of those plans. We also experienced a decline in plan asset values during 2011, which, in conjunction with the higher benefit obligations, resulted in higher unrecognized costs at December 31, 2011. The total unrecognized cost of our pension and postretirement benefits plans was $23.1 million at December 31, 2011, compared to $13.9 million at December 31, 2010.

The amounts in accumulated other comprehensive income/loss and regulatory asset for our pension and postretirement benefits plans that are expected to be recognized as a component of net benefit cost in 2012 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)	$ (5)	$	$ 19	$ (77)	$	$ (63)
Net loss	$ 339	$ 175	$ 46	$ 70	$ 91	$ 721
Amortization of pre-merger regulatory asset	$	$ 761	$	$	$ 8	$ 769

In January 2011, our former Chief Executive Officer retired and received a lump-sum pension distribution of $844,000 and $765,000 from the Chesapeake Pension Plan and Chesapeake SERP, respectively. In connection with these lump-sum payment distributions, we recorded $436,000 in pension settlement losses in addition to the net benefit cost in 2011. Based upon the current funding status of the Chesapeake Pension Plan, which does not meet or exceed 110 percent of the benefit obligation as required per the 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 will become unrestricted. Property equal to the life annuity amount will be returned to him from the escrow account. These same regulations will apply to the top 20 highest compensated employees taking distributions from the Pension Plan.

Defined Benefit Pension Plans

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.

Notes to the Consolidated Financial Statements

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.

Our funding policy provides that payments to the trustee of each 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, 2011, 2010 and 2009:

	Chesapeake Pension Plan			FPU Pension Plan		
At December 31,	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
Asset Category						
Equity securities	**51.75%**	64.33%	66.22%	**51.98%**	60.00%	63.00%
Debt securities	**37.88%**	30.60%	33.76%	**38.05%**	35.00%	29.00%
Other	**10.37%**	5.07%	0.02%	**9.97%**	5.00%	8.00%
Total	**100.00%**	100.00%	100.00%	**100.00%**	100.00%	100.00%

In December 2011, we changed the investments and investment asset allocation of our pension assets to better align them with the investment goals and objectives. This change also resulted in the pension assets of the Chesapeake Pension Plan and FPU Pension Plan being invested in similar investments. 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. Investment assets are intended to provide a level of return generating sufficient capital to meet those obligations. 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 different 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, 2011, 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				
Domestic equities	$ 3,146	$ 7,175	$	$ 10,321
Foreign equities	8,563			8,563
Alternative strategies	4,489			4,489
	16,198	7,175		23,373
Debt securities				
Fixed income	2,237	12,617		14,854
Diversifying assets		2,256		2,256
	2,237	14,873		17,110
Other				
Diversifying assets	3,586			3,586
Guaranteed deposit			897	897
Other	32			32
	3,618		897	4,515
Total Pension Plan Assets	$ 22,053	$ 22,048	$ 897	$ 44,998

At December 31, 2011, 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 guaranteed deposit accounts, which were valued based on liquidation value of those accounts, including the effect of the balance and interest guarantee and liquidation restriction.

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Prior to the change in the pension asset investments and investment allocation in December 2011, all of the equity securities held by the Chesapeake Pension Plan were classified under Level 1 of the fair value hierarchy and were recorded at fair value based on unadjusted quoted prices in active markets for identical securities. All of the debt securities and other assets held by the Chesapeake Pension Plan were classified under Level 2 of the fair value hierarchy and were recorded at fair value based on quoted market prices in active markets for similar assets or closing prices reported in active markets for those assets. All of the assets held by the FPU Pension Plan were also classified under Level 2 of the fair value hierarchy and are recorded at fair value based on net asset value per unit of those assets.

The following schedule sets forth the funded status at December 31, 2011 and 2010:

	Chesapeake Pension Plan		**FPU Pension Plan**	
At December 31,	**2011**	**2010**	**2011**	**2010**
(in thousands)				
Change in benefit obligation:				
Benefit obligation beginning of year	**$ 11,760**	$ 11,127	**$ 52,478**	$ 45,420
Interest cost	**520**	570	**2,695**	2,729
Change in assumptions	**49**	(5)		
Actuarial loss	**892**	776	**5,403**	6,326
Benefits paid	**(705)**	(708)	**(2,577)**	(1,997)
Effect of settlement	**(844)**			
Benefit obligation end of year	**11,672**	11,760	**57,999**	52,478
Change in plan assets:				
Fair value of plan assets beginning of year	**7,787**	7,449	**40,201**	36,427
Actual return on plan assets	**(124)**	490	**(1,101)**	4,605
Employer contributions	**1,048**	556	**1,313**	1,166
Benefits paid	**(705)**	(708)	**(2,577)**	(1,997)
Effect of settlement	**(844)**			
Fair value of plan assets end of year	**7,162**	7,787	**37,836**	40,201
Reconciliation:				
Funded status	**(4,510)**	(3,973)	**(20,163)**	(12,277)
Accrued pension cost	**$ (4,510)**	$ (3,973)	**$ (20,163)**	$ (12,277)
Assumptions:				
Discount rate	**4.25%**	5.00%	**4.50%**	5.25%
Expected return on plan assets	**6.00%**	6.00%	**7.00%**	7.00%

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Net periodic pension cost (benefit) for the plans for 2011, 2010 and 2009 include the components shown below:

For the Years Ended December 31,	Chesapeake Pension Plan 2011	Chesapeake Pension Plan 2010	Chesapeake Pension Plan 2009	FPU Pension Plan 2011	FPU Pension Plan 2010	FPU Pension Plan 2009 [1]
(In thousands)						
Components of net periodic pension cost:						
Interest cost	**$ 520**	$ 570	$ 547	**$ 2,695**	$ 2,729	$ 418
Expected return on assets	**(424)**	(423)	(362)	**(2,783)**	(2,532)	(396)
Amortization of prior service cost	**(5)**	(5)	(5)			
Amortization of actuarial loss	**156**	155	237			
Net periodic pension cost	**247**	297	417	**(88)**	197	22
Settlement Expense	**217**					
Amortization of pre-merger regulatory asset				**761**	888	
Total periodic cost	**$ 464**	$ 297	$ 417	**$ 673**	$ 1,085	$ 22
Assumptions:						
Discount rate	**5.00%**	5.25%	5.25%	**5.25%**	5.75%	5.50%
Expected return on plan assets	**6.00%**	6.00%	6.00%	**7.00%**	7.00%	7.00%

[1] FPU s net periodic pension cost is from the merger date (October 28, 2009) through December 31, 2009.

Pension Supplemental Executive Retirement Plan

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. The accumulated benefit obligation for the Chesapeake SERP, which is unfunded, was $2.2 million and $2.7 million, at December 31, 2011 and 2010, respectively.

At December 31,	2011	2010
(in thousands)		
Change in benefit obligation:		
Benefit obligation beginning of year	**$ 2,731**	$ 2,505
Interest cost	**107**	136
Actuarial loss	**176**	179
Benefits paid	**(89)**	(89)
Effect of settlement	**(765)**	
Benefit obligation end of year	**2,160**	2,731
Change in plan assets:		
Fair value of plan assets beginning of year		
Employer contributions	**854**	89
Benefits paid	**(89)**	(89)
Effect of settlement	**(765)**	

Fair value of plan assets end of year		
Reconciliation:		
Funded status	**(2,160)**	(2,731)
Accrued pension cost	**($ 2,160)**	($ 2,731)
Assumptions:		
Discount rate	**4.25%**	5.00%

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Net periodic pension costs for the Chesapeake SERP for 2011, 2010, and 2009 include the components shown below:

For the Years Ended December 31, *(in thousands)*	2011	2010	2009
Components of net periodic pension cost:			
Interest cost	**$ 107**	$ 136	$ 130
Amortization of prior service cost	**19**	18	18
Amortization of actuarial loss	**38**	59	54
Net periodic pension cost	**164**	213	202
Settlement expense	**219**		
Total periodic cost	**$ 383**	$ 213	$ 202
Assumptions:			
Discount rate	**5.00%**	5.25%	5.25%

Other Postretirement Benefits Plans

The following schedule sets forth the status of other postretirement benefit plans:

At December 31, *(in thousands)*	Chesapeake Postretirement Plan 2011	Chesapeake Postretirement Plan 2010	FPU Medical Plan 2011	FPU Medical Plan 2010
Change in benefit obligation:				
Benefit obligation beginning of year	**$ 2,474**	$ 2,585	**$ 3,098**	$ 2,417
Service cost			**125**	76
Interest cost	**64**	121	**176**	122
Plan amendments	**(1,140)**			
Plan participants contributions	**108**	100	**88**	47
Actuarial (gain) loss	**100**	(149)	**802**	595
Benefits paid	**(210)**	(183)	**(208)**	(159)
Benefit obligation end of year	**1,396**	2,474	**4,081**	3,098
Change in plan assets:				
Fair value of plan assets beginning of year				
Employer contributions (1)	**102**	83	**120**	112
Plan participants contributions	**108**	100	**88**	47
Benefits paid	**(210)**	(183)	**(208)**	(159)
Fair value of plan assets end of year				
Reconciliation:				
Funded status	**(1,396)**	(2,474)	**(4,081)**	(3,098)
Accrued postretirement cost	**$ (1,396)**	$ (2,474)	**$ (4,081)**	$ (3,098)

Assumptions:				
Discount rate	**4.25%**	5.00%	**4.50%**	5.25%

(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 2011, 2010, and 2009 include the following components:

For the Years Ended December 31, *(in thousands)*	Chesapeake Postretirement Plan 2011	2010	2009	FPU Medical Plan 2011	2010	2009 [1]
Components of net periodic postretirement cost:						
Service cost	**$**	$	$ 3	**$ 125**	$ 76	$ 18
Interest cost	**64**	122	131	**176**	123	23
Amortization of:						
Actuarial (gain) loss	**67**	57	76	**55**	(6)	
Prior service cost	**(77)**					
Net periodic postretirement cost	**$ 54**	$ 179	$ 210	**$ 356**	$ 193	$ 41
Assumptions						
Discount rate	**5.00%**	5.25%	5.25%	**5.25%**	5.75%	5.50%

[1] FPU Medical Plan s net periodic cost includes only the cost from the merger date (October 28, 2009) through December 31, 2009. In addition, we recorded $8,000 and $9,000 in expense in 2011 and 2010, respectively, related to continued amortization of FPU s pre-merger postretirement benefit regulatory asset.

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 2011, 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 plans and FPU s plans. Since all of the pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable.

The health care inflation rate for 2011 used to calculate the benefit obligation is 6.5 percent for medical and 7.5 percent for prescription drugs for the Chesapeake Postretirement Plan; and 9.5 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 $602,000 as of January 1, 2011, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2011 by approximately $46,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $515,000 as of January 1, 2011, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2011 by approximately $39,000.

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Estimated Future Benefit Payments

In 2012, we expect to contribute $443,000 and $2.0 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $88,000 to the Chesapeake SERP. We also expect to contribute $87,000 and $193,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2012. The schedule below shows the estimated future benefit payments for each of the plans previously described:

(in thousands)	Chesapeake Pension Plan(1)	FPU Pension Plan(1)	Chesapeake SERP(2)	Chesapeake Postretirement Plan(2)	FPU Medical Plan(2)(3)
2012	$ 443	$ 2,500	$ 88	$ 87	$ 193
2013	$ 513	$ 2,677	$ 87	$ 91	$ 215
2014	$ 536	$ 2,807	$ 85	$ 91	$ 244
2015	$ 605	$ 2,935	$ 134	$ 93	$ 269
2016	$ 560	$ 3,033	$ 142	$ 95	$ 272
Years 2017 through 2021	$ 3,803	$ 16,295	$ 663	$ 464	$ 1,759

(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.
(3) These amounts are shown net of estimated Medicare Part-D reimbursements of $11,000, $12,000, $13,000, $14,000 and $14,000 for the years 2012 to 2016, respectively, and $80,000 for the years 2017 through 2021.

On March 23, 2010, the Patient Protection and Affordable Care Act was signed into law. On March 30, 2010, a companion bill, the Health Care and Education Reconciliation Act of 2010, was also signed into law. Among other things, these new laws, when taken together, reduce the tax benefits available to an employer that receives the Medicare Part D subsidy. The deferred tax effects of the reduced deductibility of the postretirement prescription drug coverage must be recognized in the period these new laws were enacted. The FPU Medical Plan receives the Medicare Part D subsidy. We assessed the deferred tax effects on the reduced deductibility as a result of these new laws and determined that the deferred tax effects were not material to our financial results.

Notes to the Consolidated Financial Statements

Retirement Savings Plan

Effective January 1, 2012, we sponsor one 401(k) retirement savings plan and one non-qualified supplemental employee 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 the eligible compensation, including pre-tax contributions made by BravePoint employees. 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.

Effective January 1, 1999, we began offering a non-qualified supplemental employee retirement savings plan (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. These same funds are available for investment of employee contributions within Chesapeake s 401(k) plan. 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 $1.7 million and $2.4 million at December 31, 2011 and 2010, respectively. (See Note G, Investments, to the Consolidated Financial Statements for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Prior to January 1, 2012, we sponsored two separate 401(k) retirement savings plans, one for FPU employees and the second one covering all other Chesapeake employees. From January 1, 2011 to December 31, 2011, benefits offered under the two separate 401(k) retirement savings plans were substantially the same. Those benefits were also similar to the benefits offered under the one combined 401(k) retirement savings plan effective January 1, 2012.

Prior to January 1, 2011, FPU s 401(k) plan provided a matching contribution of 50 percent of an employee s pre-tax contributions, up to six percent of the employee s salary, for a maximum company contribution of up to three percent. For non-union employees the plan provided a company match of 100 percent for the first two percent of an employee s contribution, and a match of 50 percent for the next four percent of an employee s contribution, for a total company match of up to four percent. Employees were automatically enrolled at the three percent contribution, with the option of opting out, and were eligible for the company match after six months of continuous service, with vesting of 100 percent after three years of continuous service.

Prior to January 1, 2011, we made matching contributions up to six percent of employee s eligible pre-tax compensation for Chesapeake legacy businesses, except for BravePoint, as further explained below. The match was between 100 percent and 200 percent of the employee s contribution (up to six percent of eligible compensation), based on the employee s age and years of service. The first 100 percent was matched with Chesapeake common stock; the remaining match was invested in Chesapeake s 401(k) Plan according to each employee s investment direction. Employees were automatically enrolled at a two-percent contribution, with the option of opting out, and were eligible for the company match after three months of continuing service, with vesting of 20 percent per year.

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From July 1, 2006 to December 31, 2010, our contribution made on behalf of BravePoint employees was a 50 percent matching contribution, for up to six percent of each employee s annual compensation contributed to the plan. The matching contribution was funded in Chesapeake common stock. The plan was also amended at the same time to enable it to receive discretionary profit-sharing contributions in the form of employee pre-tax deferrals. The extent to which BravePoint had funds available for profit-sharing was dependent upon the extent to which the segment s actual earnings exceeded budgeted earnings. Any profit-sharing dollars made available to employees could be deferred into the plan and/or paid out in the form of a bonus.

Contributions to all of our 401(k) plans totaled $2.0 million for the year ended December 31, 2011, $1.7 million for the year ended December 31, 2010, and $1.6 million for the year ended December 31, 2009. As of December 31, 2011, there are 580,484 shares reserved to fund future contributions to the 401(k) plans.

Deferred Compensation Plan

On December 7, 2006, the Board of Directors approved the Chesapeake Utilities Corporation Deferred Compensation Plan (Deferred Compensation Plan), as amended, effective January 1, 2007. The Deferred Compensation Plan is a non-qualified, deferred compensation arrangement under which certain 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. At December 31, 2011, the Deferred Compensation Plan consisted solely of shares of common stock related to the deferral of executive performance shares and directors stock retainers.

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 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 Balance Sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled $817,000 and $777,000 at December 31, 2011 and 2010, respectively.

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N. Share-Based Compensation Plans

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and the Performance Incentive Plan (PIP), respectively. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was granted.

The table below presents the amounts included in net income related to share-based compensation expense, for the restricted stock awards issued under the DSCP and the PIP for the years ended December 31, 2011, 2010 and 2009:

For the Years Ended December 31, *(in thousands)*	**2011**	**2010**	**2009**
Directors Stock Compensation Plan	**$ 407**	$ 283	$ 191
Performance Incentive Plan	**1,043**	872	1,115
Total compensation expense	**1,450**	1,155	1,306
Less: tax benefit	**581**	463	523
Share-Based Compensation amounts included in net income	**$ 869**	$ 692	$ 783

Stock Options

We did not have any stock options outstanding at December 31, 2011 or 2010, nor were any stock options issued during 2011, 2010 and 2009.

Directors Stock Compensation Plan

Under the DSCP, each of our non-employee directors received in May 2011 an annual retainer of 900 shares of common stock. Shares granted under the DSCP are issued in advance of the directors service period; therefore, these shares are fully vested as of the grant date. We record a prepaid expense as of the date of the grant equal to the fair value of the shares issued and amortize the expense equally over a service period of one year.

A summary of stock activity under the DSCP is presented below:

	Number of Shares	**Weighted Average Grant Date Fair Value**
Outstanding December 31, 2009		
Granted [(1)]	9,900	$ 29.99
Vested	9,900	$ 29.99
Forfeited		
Outstanding December 31, 2010		
Granted [(1)]	11,104	$ 41.02
Vested	11,104	$ 41.02
Forfeited		

Outstanding	December 31, 2011

(1) In January 2011, our former Chief Executive Officer John Schimkaitis, retired from the Company and was awarded 304 shares of common stock for the prorated portion of his service period as he began his service as a non-executive board member.

We recorded compensation expense of $407,000, $283,000 and $191,000 related to DSCP awards for the years ended December 31, 2011, 2010 and 2009, respectively.

The weighted average grant-date fair value of DSCP awards granted during 2011 and 2010 was $41.02 and $29.99, per share, respectively. The intrinsic values of the DSCP awards are equal to the fair value of these awards on the date of grant. At December 31, 2011, there was $148,000 of unrecognized compensation expense related to DSCP awards that is expected to be recognized over the first four months of 2012.

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As of December 31, 2011, there were 23,111 shares reserved for issuance under the DSCP.

Performance Incentive Plan

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.

In 2007, the Board of Directors granted each executive officer equity incentive awards, which entitled each to earn shares of common stock to the extent that we achieved pre-established performance goals at the end of a one-year performance period. In 2008, we adopted multi-year performance plans to be used in lieu of the one-year awards. Similar to the one-year plans, the multi-year plans provide incentives based upon the successful achievement of long-term goals, growth and financial results, and they are comprised of both market-based and performance-based conditions or targets.

The multi-year shares granted under the PIP in 2008 vested in 2011, and the fair value of each share is equal to the market price of our common stock on the date of the grant. The shares granted under the 2009, 2010 and 2011 long-term plans have not vested as of December 31, 2011, and the fair value of each 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 market-based award granted.

In conjunction with his retirement, our former Chief Executive Officer forfeited 24,000 shares, which represents the shares awarded under the PIP in January 2009 for the performance period ending December 31, 2011 and in January 2010 for the performance period ending December 31, 2012, that had not vested.

A summary of stock activity under the PIP is presented below:

	Number of Shares	Weighted Average Fair Value
Outstanding December 31, 2009	123,075	$ 28.15
Granted	40,875	29.38
Vested	43,960	27.94
Fortfeited		
Expired	18,840	27.94
Outstanding December 31, 2010	101,150	$ 28.78
Granted	41,664	40.16
Vested	31,400	27.63
Fortfeited	24,000	29.31
Expired		
Outstanding December 31, 2011	87,414	$ 34.47

In 2011 and 2010 (in 2009, no shares under the PIP vested), 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 12,324 and 17,695 for 2011 and 2010, respectively, was based on the value of the PIP shares on their vesting date, determined by the average of the high and low of our stock price. No payments for the employee s tax obligations were made to taxing authorities in 2009 as no shares vested during this period. Total payments for the employees tax obligations to the taxing authorities were approximately $496,000 and $538,000 in 2011 and 2010, respectively.

We recorded compensation expense of $1.0 million, $872,000 and $1.1 million related to the PIP for the years ended December 31, 2011, 2010, and 2009, respectively.

Notes to the Consolidated Financial Statements

The weighted average grant-date fair value of PIP awards granted during 2011, 2010 and 2009 was $40.16, $29.38 and $29.19, per share, respectively. The intrinsic value of the PIP awards was $1.9 million, $2.7 million and $2.1 million for 2011, 2010 and 2009, respectively.

As of December 31, 2011, there were 325,952 shares reserved for issuance under the PIP.

O. Rates and other regulatory activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSCs; 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

Capacity Release: On September 2, 2008, our Delaware division filed with the Delaware PSC its annual Gas Sales Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2008. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, which included the Delaware PSC, our Delaware division and the Division of the Public Advocate. As part of the settlement agreement, the parties agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, PESCO. On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates under asymmetrical pricing principles and the amount actually received by the Delaware division for capacity released to PESCO. The Hearing Examiner also recommended that the Delaware PSC require us to adhere to asymmetrical pricing principles in all future capacity releases by the Delaware division to PESCO, if any. If the Hearing Examiner s refund recommendation for past capacity releases had ultimately been approved without modification by the Delaware PSC, the Delaware division would have had to credit to its firm service customers amounts equal to the maximum tariff rates that the Delaware division paid for long-term capacity, which we estimated to be approximately $700,000, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. On February 18, 2010, we filed exceptions to the Hearing Examiner s recommendations.

At the hearing on March 30, 2010, the Delaware PSC agreed with us that the Delaware division had been releasing capacity based on a previous settlement approved by the Delaware PSC and, therefore, did not require the Delaware division to issue any refunds for past capacity releases. The Delaware PSC, however, required the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO until a more appropriate pricing methodology is developed and approved. The Delaware PSC issued an order on May 18, 2010, elaborating its decisions at the March hearing and directing the parties to reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity releases by the Delaware division to PESCO.

On June 17, 2010, the Division of the Public Advocate filed an appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to refunds for past capacity releases. On June 28, 2010, the Delaware division filed a Notice of Cross Appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to requiring the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO. On June 13, 2011, the Delaware Superior Court issued its decision affirming all aspects of the Delaware PSC s Order on May 18, 2010, which included its decision not to require the Delaware division to issue any refunds for past releases.

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On June 29, 2011, the Delaware Attorney General filed an appeal with the Delaware Supreme Court, asking it to review the Delaware Superior Court s decision affirming the Delaware PSC decision with regard to refunds for past capacity releases. On July 12, 2011, the Delaware division filed a Notice of Cross Appeal with the Delaware Supreme Court, asking it to overturn the Superior Court s decision with regard to the Delaware PSC s decision on future capacity releases to PESCO. On August 3, 2011, the Delaware Attorney General filed a Notice of Dismissal with the Supreme Court withdrawing its appeal. Consequently, on August 4, 2011, the Delaware division filed a Notice of Dismissal with the Supreme Court to withdrawal its cross appeal and the filing of the Notice of Dismissal eliminates any potential liability related to potential refunds for past capacity releases and the matter is officially closed. The parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases by the Delaware division to PESCO or any other affiliates.

Our Delaware division also had developments in the following matters with the Delaware PSC:

On September 1, 2010, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2010. On September 21, 2010, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2010, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware PSC granted approval of the GSR charges at its regularly scheduled meeting on June 7, 2011.

On March 10, 2011, the Delaware division filed with the Delaware PSC an application requesting approval to guarantee certain debt of FPU. Specifically, the Delaware division sought approval to execute a Seventeenth Supplemental Indenture, in which Chesapeake guarantees the payment of certain debt of FPU and FPU is permitted to deliver Chesapeake s consolidated financial statements in lieu of FPU s stand-alone financial statements to satisfy certain covenants within the indentures of FPU s debt. The Delaware PSC granted approval of the guarantee of certain debt of FPU at its regularly scheduled meeting on April 4, 2011.

On September 1, 2011, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2011. On September 20, 2011, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed, on November 1, 2011, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. We anticipate that the Delaware PSC will render a final decision on the GSR charges in the second or third quarter of 2012.

On September 19, 2011, the Delaware division filed with the Delaware PSC two applications seeking approval to begin charging customers for the franchise fees imposed upon the Delaware division by the City of Lewes, Delaware and the Town of Dagsboro, Delaware. On October 3, 2011, the Delaware PSC issued orders on both matters, effectively opening the proceedings and setting evidentiary hearings for November 8, 2011. The Delaware PSC granted approval for the franchise fees at its regularly scheduled meeting on November 8, 2011.

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Maryland

On December 14, 2010, the Maryland PSC held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Maryland division during the 12 months ended September 30, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

On March 2, 2011, the Maryland division filed with the Maryland PSC an application for the approval of a franchise executed between the Maryland division and the Board of County Commissioners of Cecil County, Maryland. In this franchise agreement, the County granted the Maryland division a 50-year, non-exclusive franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Cecil County. On April 11, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Cecil County, subject to no adverse comments being received within 30 days after the issuance of the Order. On May 10, 2011, comments opposing the application were filed by Pivotal Utility Holdings, Inc. d/b/a Elkton Gas (Pivotal). Pivotal also provides natural gas service to customers in a portion of Cecil County. On June 8, 2011, the Maryland PSC granted the Maryland division the authority to exercise its franchise in a majority of the area requested in the Maryland division s application. The approval for a small portion of the area within the requested franchise area, which is closest to the area served by Pivotal, was withheld until an evidentiary hearing could be convened. On August 16, 2011, the Maryland division submitted testimony in support of its proposed boundary with Pivotal. On September 29, 2011, the parties in the proceeding (Maryland division, Pivotal, Maryland PSC Staff, and the Office of People s Counsel) submitted a proposed settlement agreement for the Maryland PSC s consideration that outlined an agreed upon boundary between the Maryland division and Pivotal in the small portion of Cecil County that was subject to further review. On October 12, 2011, the assigned Public Utility Law Judge in this matter issued a Proposed Order, approving the proposed settlement agreement as submitted by the parties in the proceeding. The Proposed Order became a final order of the Maryland PSC on November 15, 2011.

On May 17, 2011, the Maryland division filed with the Maryland PSC an application for approval of a franchise executed between the Maryland division and the Board of County Commissioners for Worcester County, Maryland. In this franchise agreement, the County granted the Maryland division a 25-year, non-exclusive franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Worcester County. On June 14, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Worcester County, subject to no adverse comments being received within 20 days after the issuance of the Order. No adverse comments were filed within the comment period, and the order became effective on July 5, 2011.

On August 12, 2011, the Maryland division submitted a request to the Maryland PSC for approval of a negotiated delivery service rate for a large customer on its system. At its regularly scheduled meeting on September 21, 2011, the Maryland PSC granted approval of the negotiated delivery service rate effective for bills rendered after that date.

On December 12, 2011, the Maryland PSC held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Maryland division during the 12 months ended September 30, 2011. No issues were raised at the hearing, and on December 13, 2011, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on December 29, 2011.

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Florida

Come-Back Filing: As part of our 2010 rate case settlement in Florida, the Florida PSC required us to submit a Come-Back filing, detailing all known benefits, synergies, cost savings and cost increases resulting from the merger with FPU. We submitted this filing on April 29, 2011, and requested the recovery, through rates, of approximately $34.2 million in acquisition adjustment (the price paid in excess of the book value) and $2.2 million in merger-related costs. In the past, the Florida PSC has allowed recovery of an acquisition adjustment under certain circumstances to provide an incentive for larger utilities to purchase smaller utilities. The Florida PSC requires a company seeking recovery of the acquisition adjustment and merger-related costs to demonstrate that customers will benefit from the acquisition. They use the following five factor test to determine if the customers are benefiting from the transaction: (a) increased quality of service; (b) lower operating costs; (c) increased ability to attract capital for improvements; (d) lower overall cost of capital; and (e) more professional and experienced managerial, financial, technical and operational resources. With respect to lower costs, the Florida PSC effectively requires that the synergies be sufficient to offset the rate impact of the recovery of the acquisition adjustment and merger-related costs.

At the December 6, 2011 agenda conference, the Florida PSC approved the following: (a) FPU and the Florida division of Chesapeake have complied with the reporting requirements in the 2010 rate case settlement; (b) FPU is authorized to reflect an acquisition adjustment of $34.2 million, to be amortized over a 30-year period using the straight-line method beginning in November 2009; (c) FPU is authorized to reflect a regulatory asset of $2.2 million for the merger-related costs, to be amortized over a five-year period using the straight-line method beginning in November 2009; (d) FPU and the Florida division of Chesapeake are not permitted to consolidate the earnings surveillance reporting and accounting records until such time as the rates and tariffs are combined; (e) FPU and the Florida division of Chesapeake are not permitted to establish a combined benchmark for the purpose of evaluating incremental cost increases in their future rate proceedings until those entities are functioning as a single utility for regulatory purposes; and (f) FPU and the Florida division of Chesapeake do not have any 2010 excess earnings to be refunded to customers.

The Florida PSC Order allows us to classify the acquisition adjustment and merger-related costs as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, our rate of return calculation will be based upon this higher level of investment, which effectively enables us to earn a return on this investment. Pursuant to the Order, we reclassified to a regulatory asset at December 31, 2011, $31.7 million of the $34.2 million goodwill, which represents the portion of the goodwill allowed to be recovered in future rates after the effective date of the Florida PSC Order. We also recorded as a regulatory asset $18.1 million related to the gross-up of the acquisition adjustment for income tax. The $1.3 million of the $2.2 million of merger-related costs, which represent the portion of the merger-related costs allowed to be recovered in future rates after the effective date of the Florida PSC Order, had previously been deferred as a regulatory asset. We also recorded as a regulatory asset $349,000 related to the gross-up of the merger-related costs for income tax. As a result of this Order, we will record $2.4 million ($1.4 million, net of tax) in amortization expense related to these assets in 2012 and 2013, $2.3 million ($1.4 million, net of tax) in 2014 and $1.8 million ($1.1 million, net of tax) annually, thereafter until 2039. These amortization expenses will be a non-cash charge, and the net effect of the recovery will be positive cash flow. Over the long-term, however, the inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have otherwise been able to achieve.

In FPU s future rate proceedings, if it is determined that the level of cost savings supporting the lower operating costs in its request for the recovery of the acquisition adjustment no longer exists, the remaining acquisition adjustment may be partially or entirely disallowed by the Florida PSC. In such event, we will have to expense the corresponding amount of the disallowed acquisition adjustment.

The Florida PSC Order also resulted in the reversal in December 2011, of the $750,000 regulatory accrual, which was recorded in 2010 based on management s assessment of FPU s earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in this Come-Back filing. The reversal of the $750,000 regulatory accrual was reflected in operating revenue in 2011 in the accompanying consolidated statements of income.

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Peninsula Pipeline: On September 19, 2011, Peninsula Pipeline filed a petition seeking the Florida PSC s approval of a Firm Transportation Agreement (FTA) between Peninsula Pipeline and FPU, an affiliated company, in accordance with its tariff. On February 8, 2012 Peninsula Pipeline filed a petition with the Florida PSC seeking approval of an amended and revised FTA between Peninsula Pipeline and FPU. This amended and revised FTA provides for upstream interconnection of Peninsula Pipeline s facilities with the Peoples Gas distribution facilities at the Duval/Nassau County line and several downstream interconnections with FPU s facilities. This amended and revised FTA replaces, in its entirety, the agreement originally filed on September 19, 2011. The revised and amended FTA comes as a result of negotiations between Peoples Gas, FPU, and Peninsula Pipeline, which resulted in a territorial agreement and related service arrangements described below.

In January 2012, Peninsula Pipeline executed an agreement with Peoples Gas for the joint construction, ownership and operation of an approximately 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. Under the terms of the agreement, Peninsula Pipeline will own approximately 45 percent of this 16-mile pipeline. Peninsula Pipeline s portion of the estimated project cost is $5.7 million. Peoples Gas will operate the pipeline and Peninsula Pipeline will be responsible for its portion of the operation and maintenance expenses of the pipeline based on its ownership percentage. Peninsula Pipeline will contract with Peoples Gas for capacity from the unaffiliated upstream interstate pipeline to this jointly-owned pipeline. Peninsula Pipeline will utilize both the capacity contracted with Peoples Gas and the capacity on the new jointly-owned pipeline to provide transportation service to FPU for its natural gas distribution service in Nassau County. The new jointly-owned pipeline is expected to be completed and placed into service in the second half of 2012.

Marianna Franchise: On July 7, 2009, the Marianna Commission adopted an ordinance granting a franchise to FPU effective February 1, 2010 for a period not to exceed 10 years for the operation and distribution and/or sale of electric energy (the Franchise Agreement). The Franchise Agreement provides that FPU will develop and implement new TOU and interruptible electric power rates, or other similar rates, mutually agreeable to FPU and the City of Marianna. The Franchise Agreement further provides for the TOU and interruptible rates to be effective no later than February 17, 2011, and available to all customers within FPU s Northwest Division, which includes the City of Marianna. If the rates were not in effect by February 17, 2011, the City of Marianna would have the right to give notice to FPU within 180 days thereafter of its intent to exercise an option in the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and by the referendum, the closing of the purchase must occur within 12 months after the referendum is approved. If the City of Marianna elects to purchase the Marianna property, the Franchise Agreement requires the City of Marianna to pay FPU the fair market value for such property as determined by three qualified appraisers. Future financial results would be negatively affected by the loss of earnings generated by FPU from its approximately 3,000 customers in the City under the Franchise Agreement.

In accordance with the terms of the Franchise Agreement, FPU developed TOU and interruptible rates and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an Order approving FPU s petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna objected to the proposed rates and filed a petition protesting the entry of the Florida PSC s Order. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

On January 26, 2011, FPU filed a petition with the Florida PSC for approval of an amendment to FPU s Generation Services Agreement entered into between FPU and Gulf Power. The amendment provides for a reduction in the capacity demand quantity, which generates the savings necessary to support the TOU and interruptible rates approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019. Pursuant to its Order dated June 21, 2011, the Florida PSC approved the amendment. On July 12, 2011, the City of Marianna filed a protest of this decision and requested a hearing on the amendment. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

On April 7, 2011, FPU filed a petition for approval of a mid-course reduction to its Northwest Division fuel rates based on two factors: (1) the previously discussed amendment to the Generation Services Agreement with Gulf Power, and (2) a weather-related increase in sales resulting in an accelerated collection of the prior year s under-recovered costs. Pursuant to its Order dated July 5, 2011, the Florida PSC approved the petition, which reduced the fuel rates of FPU s northwest division.

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On February 24, 2012, FPU filed a revised petition for approval of a mid-course reduction to its Northwest Division fuel rates based on a mid-course reduction to its supplier s fuel rates. FPU expects to significantly lower purchased power costs for its Northwest Division in 2012 as a result of this reduction by the supplier. In order to ensure that its customers receive these significant savings in the most timely manner, FPU filed this petition. We anticipate Florida PSC s decision on this petition in April 2012.

As disclosed in Note Q, Other Commitments and Contingencies, to the Consolidated Financial Statements, the City of Marianna, on March 2, 2011, filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU s property in the City of Marianna in accordance with the terms of the Franchise Agreement. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegation by the City of Marianna and asserted affirmative defenses. The litigation remains pending and discovery is still underway.

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

On June 21, 2011, FPU, in accordance with the Florida PSC rules, filed its 2011 depreciation study and request for new depreciation rates effective January 1, 2012 for its electric distribution operation. The Florida PSC approved the depreciation study at its January 24, 2012 Agenda Conference. The new approved depreciation rates are expected to reduce annual depreciation expense by approximately $227,000.

On February 3, 2012, FPU s natural gas distribution operation and the Florida Division of Chesapeake filed a petition with the Florida PSC for approval of a surcharge to customers for a Gas Reliability Infrastructure Program. We are seeking approval to recover costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic (Polyethylene)) in their respective systems. If the petition is approved, we will replace qualifying mains and services over a 10-year period.

Eastern Shore

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

Energylink Expansion Project: In 2006, Eastern Shore proposed to develop, construct and operate approximately 75 miles of new pipeline facilities from the existing Cove Point Liquefied Natural Gas terminal in Calvert County, Maryland, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, Maryland, to points on the Delmarva Peninsula, where such facilities would interconnect with Eastern Shore s existing facilities in Sussex County, Delaware. In April 2009, Eastern Shore terminated this project based on increased construction costs over its original projection. As approved by the FERC, Eastern Shore initiated billing to recover approximately $3.2 million of costs incurred in connection with this project and the related cost of capital over a period of 20 years in accordance with the terms of the precedent agreements executed with the two participating customers. One of the two participating customers is Chesapeake, through its Delaware and Maryland divisions. During 2010, Eastern Shore and the participating customers negotiated to reduce the recovery period of this cost from 20 years to five years. On January 27, 2011, Eastern Shore filed with the FERC the request to amend the cost recovery period, which was approved by the FERC on February 14, 2011. Eastern Shore revised its billing to reflect the five-year surcharge, effective March 1, 2011.

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Rate Case Filing: On December 30, 2010, Eastern Shore filed with the FERC a base rate proceeding in accordance with the terms of the settlement in its prior base rate proceeding. The rate filing reflected increases in operating and maintenance expenses, depreciation expense, and a return on existing and new gas plant facilities expected to be placed into service before June 30, 2011. The FERC issued a notice of the filing on January 3, 2011. Protests were received from several interested parties, and other parties intervened in the proceeding. On January 31, 2011, the FERC issued its Order accepting the filing and suspending its effectiveness for the full five-month period permitted under the Natural Gas Act. The discovery process commenced on February 22, 2011, and the FERC Staff performed an on-site audit on March 16-17, 2011. Subsequent to the on-site audit, settlement conferences involving Eastern Shore, the FERC Staff and other interested parties resulted in a settlement, which provides a cost of service of approximately $29.1 million and a pre-tax return of 13.9 percent. Also included in the settlement is a negotiated rate adjustment, effective November 1, 2011, associated with the phase-in of an additional 15,000 Dts/d of new transportation service on Eastern Shore s eight-mile extension to interconnect with TETLP s pipeline system. This rate adjustment reduces the rate per Dt of the service on this eight-mile extension by reflecting the increased service of 15,000 Dts/d with no additional revenue. This rate adjustment effectively offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm service although Eastern Shore may still benefit from the increased commodity charge on the increased volume from the phase-in of service. The settlement also provides a five-year moratorium on the parties rights to challenge Eastern Shore s rates and on Eastern Shore s right to file a base rate increase. The settlement 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. The FERC approved the settlement on January 24, 2011.

From July 2011 through October 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the FERC s approval of the new rates. From November 2011, Eastern Shore adjusted its billing to reflect the settlement rates, subject to refund to customers upon FERC s approval of the settlement. As of December 31, 2011, Eastern Shore has recorded approximately $1.3 million as a regulatory liability related to the refund due to customers as a result of the settlement, which refund was paid in January and February 2012.

Mainline Extension Project: On April 1, 2011, Eastern Shore filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 3,405 Dts/d of natural gas to an existing industrial customer. The FERC published notice of this filing on April 7, 2011. The 60-day comment period subsequent to the FERC notice expired on June 6, 2011, and the requested authorization became effective on that date.

On April 28, 2011, Eastern Shore filed a notice of intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 6,250 Dts/d of natural gas to Chesapeake s Delaware and Maryland divisions and Eastern Shore Gas, an unaffiliated provider of piped propane service in Maryland. The FERC published notice of this filing on May 12, 2011, and one of Eastern Shore s customers filed a conditional protest with the FERC, which it withdrew on July 29, 2011. Upon withdrawal of the protest, the requested authorization became effective.

Also on April 28, 2011, Eastern Shore filed a notice of intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 4,070 Dts/d of natural gas to Chesapeake s Maryland division to provide new natural gas service in Cecil County, Maryland. The FERC published notice of this filing on May 12, 2011, and one of Eastern Shore s customers filed a conditional protest with the FERC, which it withdrew on July 29, 2011. Upon withdrawal of the protest, the requested authorization became effective.

Eastern Shore also had developments in the following FERC matters:

On March 7, 2011, Eastern Shore filed certain tariff sheets to amend the creditworthiness provisions contained in its FERC Gas Tariff. On April 6, 2011, the FERC issued an Order accepting and suspending Eastern Shore s filed tariff revisions for an effective date of April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to several proposed revisions.

On April 18, 2011, Eastern Shore submitted its annual Interruptible Revenue Sharing Report to the FERC. Eastern Shore reported in this filing that its interruptible revenue did not exceed its annual threshold amount, which would trigger sharing of excess interruptible revenues with its firm service customers. Consequently, Eastern Shore is not required to refund to its firm customers any portion of its interruptible revenue received for the period April 2010 through March 2011.

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On June 24, 2011, Eastern Shore filed certain tariff sheets to amend the General Terms and Conditions and the pro forma FTA contained in its FERC Gas Tariff to allow for specification of minimum delivery pressures and maximum hourly quantity. The FERC published the notice of this filing on June 27, 2011, and no protests or adverse comments opposing this filing were submitted. On July 15, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective July 24, 2011.

On August 15, 2011, Eastern Shore filed certain tariff sheets to update certain Delivery Point Area definitions contained in its FERC Gas Tariff. The FERC published notice of this filing on August 16, 2011, and no protests or adverse comments opposing this filing were submitted. On September 13, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective September 14, 2011.

On September 7, 2011, Eastern Shore filed certain tariff sheets to reflect a decrease in the Annual Charge Adjustment, which is a surcharge designed to recover applicable program costs incurred by the FERC to discharge its jurisdictional responsibilities. The surcharge decreased from $0.0019 per Dt to $0.0018 per Dt. The FERC published the notice of this filing on September 8, 2011, and no protests or adverse comments opposing this filing were submitted. On September 27, 2011, the FERC issued a Letter Order, accepting the tariff revisions as proposed, effective October 1, 2011.

P. Environmental Commitments and Contingencies

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

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

As of December 31, 2011, we had approximately $11.0 million in environmental liabilities related to all of FPU s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates. Approximately $8.3 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of December 31, 2011. We also had approximately $5.7 million in regulatory assets for future recovery of environmental costs from FPU s customers.

In addition to the FPU MGP sites, we had $254,000 in environmental liabilities at December 31, 2011, related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of December 31, 2011, we had approximately $991,000 in regulatory and other assets for future recovery through Chesapeake s rates.

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

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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 an MGP. Pursuant to a Consent Order between FPU and the FDEP, effective April 8, 1991, FPU is required to complete the delineation of soil and groundwater impacts at the site and implement an effective remedy.

On June 30, 2008, FPU transmitted to the FDEP a revised feasibility study, evaluating appropriate remedies for the site. This revised feasibility study evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. On April 30, 2009, the FDEP issued a remedial action order, which it subsequently withdrew. In response to the Order and as a condition to its withdrawal, FPU committed to perform additional field work in 2009 and complete an additional engineering evaluation of certain remedial alternatives. The scope of this work has increased in response to FDEP s requests for additional information.

FPU performed additional fieldwork in August 2010, which included the installation of additional groundwater monitoring wells and performance of a comprehensive groundwater sampling event. FPU also performed vapor intrusion sampling in October 2010. The results of the fieldwork were submitted to FDEP for their review and comment in October 2010. On November 4, 2010, FDEP issued its comments on the feasibility study and the proposed remedy.

On November 16, 2010, FPU presented to FDEP a new remedial action plan for the site, and FDEP agreed with FPU s proposal to implement a phased approach to remediation. On December 22, 2010, FPU submitted to FDEP an interim RAP to remediate the east parcel of the site, which FDEP conditionally approved on February 4, 2011. Subsequent modifications to the interim RAP, dated March 12, 2011 and April 18, 2011, were submitted to address potential concerns raised by FDEP. An Approval Order for the interim RAP was issued by FDEP on May 2, 2011, and subsequently modified by FDEP on May 18, 2011.

FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP s conditions for approval. The operations on the east parcel have been relocated, and the structures removed. New monitoring wells and Bio Sparging and Soil-Vapor Extraction (BS/SVE) test wells were installed on the east parcel in May 2011. The initial round of SVE and sparging pilot testing was conducted in June 2011, and a subsequent round of testing was conducted in July of 2011. A supplement to the interim RAP was prepared to present the findings of the pilot testing and the proposed design details for a full-scale remediation system, and was submitted to FDEP on October 31, 2011. On December 22, 2011, FDEP issued conditional approval for full-scale implementation of BS/SVE on the east parcel.

Estimated costs of remediation for the West Palm Beach site range from approximately $4.7 million to $15.8 million. We have revised our estimated maximum cost of $13.1 million to $15.8 million to include costs associated with the relocation of FPU s operations at this site, which may be necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

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

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Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In late September 2006, the EPA sent a Special Notice Letter, notifying FPU, and the other responsible parties at the site (Florida Power Corporation, Florida Power & Light Company, Atlanta Gas Light Company, and the city of Sanford, Florida, collectively with FPU, the Sanford Group), of EPA s selection of a final remedy for OU1 (soils), OU2 (groundwater), and OU3 (sediments) for the site. The EPA projected the total estimated remediation costs for this site to be approximately $12.9 million.

In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by 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 million, or $650,000. As of December 31, 2011, FPU has paid $650,000 to the Sanford Group escrow account for its share of the funding requirements.

The Sanford Group, EPA and the U.S. Department of Justice agreed to a Consent Decree in March 2008, which was entered by the Federal Court in Orlando, Florida on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. 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.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have 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.

As of December 31, 2011, FPU s remaining share of remediation expenses, including attorneys fees and costs, is 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 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, 2011.

Key West, Florida

FPU formerly owned and operated an 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 September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is requesting implementation of additional fieldwork, which FDEP believes is warranted for the site.

FPU and the current site owner have had several discussions regarding the approach to be taken with FDEP and the proposed scope of work. Representatives of FPU, FDEP and the current site owner participated in a teleconference on July 7, 2011. During that call, the scope of work was tentatively agreed upon, and FDEP agreed to proceed without using a Consent Order. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells.

FPU and the current site owner, Suburban Propane, submitted a work plan and schedule to FDEP on September 30, 2011. FDEP conditionally approved the work plan in a letter dated October 19, 2011, and further clarified the conditions of approval in an e-mail dated October 24, 2011. The two new monitoring wells were installed in November of 2011, and groundwater monitoring was begun in December 2011.

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FPU and Suburban Propane have entered into a cost-sharing agreement, whereby Suburban Propane has agreed to contribute $15,000 to complete the agreed-upon scope of work. FPU s estimated share of the cost to complete the work is $21,000. Prior to completion of the monitoring program, we cannot determine to a reasonable degree of certainty the probable costs to resolve FPU s liability for the Key West MGP Site, although we do not anticipate the cost to exceed $100,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action (NFA) determination for the site, which must include a requirement for institutional and engineering controls.

On December 13, 2011, Gulf Power, City of Pensacola, FDOT and FPU submitted a draft covenant for institutional and engineering controls for the site to the FDEP. Upon FDEP s approval and the subsequent recording of the institutional and engineering controls, no further work will be required of the parties. Assuming the FDEP approves the draft institutional and engineering controls, it is anticipated that FPU s share of remaining legal and cleanup costs will not exceed $5,000.

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. During 1996, we completed construction of an Air Sparging and Soil/Vapor Extraction system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to permanently decommission the Air Sparging and Soil/Vapor Extraction system 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 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.

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 the FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. In 2001, FDEP approved a RAP requiring construction and operation of a BS/SVE treatment system to address soil and groundwater impacts at a portion of the site. The BS/SVE treatment system has been in operation since October 2002. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. The Eighteenth Semi-Annual RAP Implementation Status Report was submitted to FDEP in December 2011. The groundwater sampling results through December 2011 show a continuing reduction in contaminant concentrations and indicate that the recent treatment system modifications and upgrades have had a beneficial impact on the rate of reduction. At present, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the BS/SVE treatment system. The total expected cost of operating and monitoring the system is approximately $46,000.

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The BS/SVE treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to FDEP for review. On June 24, 2010, FDEP provided comments on the soil excavation interim RAP by letter, to which we responded, and a subsequent conditional approval letter was issued by FDEP on August 27, 2010. The cost to implement this excavation plan has been estimated at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. Because the costs associated with shoreline stabilization and dewatering (including treatment and discharge of the pumped water) are likely to be substantial, alternatives to this excavation plan are being evaluated. One alternative currently being evaluated involves sparging into the southwest portion of the property to treat soils rather than excavating the soils. Two new sparge points were installed in the southwest portion of the property in February of 2011. Sparging into these points has been initiated, and operational and monitoring data over the next few quarters should provide the information needed to make this evaluation.

FDEP has indicated that we may be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, we object to FDEP s suggestion that the sediments have been adversely impacted by the former operations of the MGP. Our early estimates indicate that some of the corrective measures discussed by FDEP could cost as much as $1.0 million. We believe that corrective measures for the sediments are not warranted and intend to oppose any requirement that we undertake corrective measures in the offshore sediments. We have not recorded a liability for sediment remediation, as the final resolution of this matter cannot be predicted at this time.

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.

Q. Other Commitments and Contingencies

Litigation

In May 2010, an FPU propane customer filed a class action complaint against FPU in Palm Beach County, Florida, alleging, among other things, that FPU acted in a deceptive and unfair manner related to a particular charge by FPU on its bills to propane customers and the description of such charge. The suit sought to certify a class comprised of FPU propane customers to whom such charge was assessed since May 2006 and requested damages and statutory remedies based on the amounts paid by FPU customers for such charge. FPU vigorously denied any wrongdoing and maintained that the particular charge at issue is customary, proper and fair. Without admitting any wrongdoing, validity of the claims or a properly certifiable class for the complaint, FPU entered into a settlement agreement with the plaintiff in September 2010 to avoid the burden and expense of continued litigation. The court approved the final settlement agreement, and the judgment became final on March 13, 2011. In 2010, we recorded $1.2 million of the total estimated costs related to this litigation. Pursuant to the final settlement agreement, the distribution to the class was completed by May 13, 2011.

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On March 2, 2011, the City of Marianna, Florida filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU s customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU s property. On August 31, 2011, FPU advised the City of Marianna that it has no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU s property. At a hearing on January 10, 2012 the judge presiding over this case set plaintiff s motion for summary judgment for hearing on April 2, 2012. The court directed the parties to complete by March 23, 2012, depositions necessary for consideration at the summary judgment hearing. The court also set the case for trial commencing July 30, 2012. We anticipate that the case will be tried at this time. FPU intends to continue its vigorous defense of the lawsuit filed by the City of Marianna and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

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

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations and propane wholesale marketing operation have entered into contractual commitments to purchase gas, electricity and propane from various suppliers. The contracts have various expiration dates. We have a contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2013.

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

In May 2011, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2012. PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements before the existing agreements expire.

As discussed in Note O Rates and Other Regulatory Activities, on January 25, 2011, FPU entered into an amendment to its Generation Services Agreement with Gulf Power, which reduces the capacity demand quantity and provides the savings necessary to support the TOU and interruptible rates for the customers in the City of Marianna, both of which were approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019.

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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 result 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. 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 agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operation 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 action taken or proposed to be taken to be compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. FPU was in compliance with these requirements as of December 31, 2011.

The total purchase obligations for natural gas, electric and propane supplies are $99.2 million for 2012, $70.6 million for 2013 2014, $61.1 million for 2015 2016 and $122.9 million thereafter.

Corporate Guarantees

The Board of Directors has authorized the Company to issue up to $45 million of corporate guarantees on behalf of our subsidiaries and for letters of credit.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2011 was $27.6 million, with the guarantees expiring on various dates through December 2012.

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 J, Long-Term Debt, to the Consolidated Financial Statements for further details).

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2012, 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 $656,000, which expires on December 2, 2012, as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed the letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of December 31, 2011. 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 $2.5 million to TETLP related to the Precedent Agreement with TETLP, which is further described below.

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP s mainline system by up to 190,000 Dts/d. The Precedent Agreement provides that, upon satisfaction of certain conditions, the parties will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 34,100 Dts/d and 15,900 Dts/d, respectively. The 34,000 Dts/d for our Delaware division and15,900 Dts/d for our Maryland division reflect the additional volume subscribed to by our divisions above the volume originally agreed to by the parties. These contracts will be effective on the service commencement date of the project, which is currently projected to occur in November 2012. Each firm transportation service contract shall, among other things, provide for: (a) the maximum daily quantity of Dts/d described above; (b) a term of 15 years; (c) a receipt point at Clarington, Ohio; (d) a delivery point at Honey Brook, Pennsylvania; and (e) certain credit standards and requirements for security. Commencement of service and TETLP s and our rights and obligations under the two firm transportation service contracts are subject to satisfaction of various conditions specified in the Precedent Agreement.

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Our Delmarva natural gas supplies have been received primarily from the Gulf of Mexico natural gas production region and have been transported through three interstate upstream pipelines, two of which interconnect directly with Eastern Shore s transmission system. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide gas supply through an additional direct interconnection with Eastern Shore s transmission system and provide access to new sources of supply from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth.

The Precedent Agreement provides that the parties shall promptly meet and work in good faith to negotiate a mutually acceptable reservation rate. Failure to agree upon a mutually acceptable reservation rate would have enabled either party to terminate the Precedent Agreement, and would have subjected us to reimburse TETLP for certain pre-construction costs; however, on July 2, 2010, our Delaware and Maryland divisions executed the required reservation rate agreements with TETLP.

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP s pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $6.1 million as of December 31, 2011. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2012, our proportionate share could be as much as approximately $50 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote.

As previously mentioned, we have provided a letter of credit to TETLP for $2.5 million, which is the maximum amount required under the Precedent Agreement with TETLP.

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with Eastern Shore to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. As discussed in Note O, Rates and Other Regulatory Activities, to Consolidated Financial Statements, Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transportation service on this extension is Eastern Shore s current tariff rate for service in that area.

In November 2011, TETLP obtained the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project from the FERC. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or Eastern Shore.

As the Eastern Shore and TETLP firm transportation services commence, our Delaware and Maryland divisions incur costs for those services based on the agreed and FERC-approved reservation rates, which will become an integral component of the costs associated with providing natural gas supplies to our Delaware and Maryland divisions and will be included in the annual GSR filings for each of our respective divisions.

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing sales tax audits in Florida. As of December 31, 2011 and 2010, we maintained accruals of $307,000 and $698,000, respectively, related to additional sales taxes and gross receipts taxes that we may owe to various states.

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Notes to the Consolidated Financial Statements

R. 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)				
2011				
Operating Revenue	**$ 146,597**	**$ 86,831**	**$ 80,610**	**$ 103,988**
Operating Income	**$ 24,839**	**$ 7,776**	**$ 5,594**	**$ 15,495**
Net Income	**$ 13,747**	**$ 3,520**	**$ 2,397**	**$ 7,957**
Earnings per share:				
Basic	**$ 1.44**	**$ 0.37**	**$ 0.25**	**$ 0.83**
Diluted	**$ 1.43**	**$ 0.37**	**$ 0.25**	**$ 0.83**
2010				
Operating Revenue	$ 153,260	$ 80,061	$ 76,466	$ 117,759
Operating Income	$ 25,398	$ 7,761	$ 4,583	$ 14,188
Net Income	$ 13,974	$ 3,340	$ 1,628	$ 7,113
Earnings per share:				
Basic	$ 1.48	$ 0.35	$ 0.17	$ 0.75
Diluted	$ 1.47	$ 0.35	$ 0.17	$ 0.74

(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

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated the Company s 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, 2011. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of December 31, 2011.

Changes 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, 2011, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. Chesapeake has included FPU s activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions for additional information relating to the FPU merger.

CEO and CFO Certifications

The Company s 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 the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2011. In addition, on June 2, 2011 the Company s Chief Executive Officer certified to the NYSE that he was not aware of any violation by the Company 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, Chesapeake s management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in a report entitled Internal Control Integrated Framework, issued 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.

Chesapeake s management has evaluated and concluded that Chesapeake s internal control over financial reporting was effective as of December 31, 2011.

Our independent auditors, ParenteBeard LLC, have audited and issued their report on effectiveness of our internal control over financial reporting. That report appears on the following page.

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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, 2011, based on criteria established in *Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).* Chesapeake Utilities Corporation 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, Chesapeake Utilities Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Chesapeake Utilities Corporation as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, stockholders equity and cash flows of Chesapeake Utilities Corporation, and our report dated March 7, 2012 expressed an unqualified opinion.

/s/ ParenteBeard LLC
ParenteBeard LLC
Malvern, Pennsylvania
March 7, 2012

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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, 2012, in connection with the Company s Annual Meeting to be held on or about May 2, 2012.

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, under the caption Executive Officers of the Company.

The Company has adopted a Code of Ethics for Financial Officers, which applies to its 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, 2012, in connection with the Company s Annual Meeting to be held on or about May 2, 2012.

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, 2012, in connection with the Company s Annual Meeting to be held on or about May 2, 2012.

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The following table sets forth information, as of December 31, 2011, with respect to compensation plans of Chesapeake and its subsidiaries, 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			372,413 [(1)]
Equity compensation plans not approved by security holders			
Total			372,413

(1) Includes 325,952 shares under the 2005 Performance Incentive Plan, 23,111 shares available under the 2005 Directors Stock Compensation Plan, and 23,350 shares available under the 2005 Employee Stock Awards Plan.

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, 2012 in connection with the Company s Annual Meeting to be held on or about May 2, 2012.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

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, 2012, in connection with the Company s Annual Meeting to be held on or about May 2, 2012.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) The following documents are filed as part of this report:

1. Financial Statements:

Report of Independent Registered Public Accounting Firm;

Consolidated Statements of Income for each of the three years ended December 31, 2011, 2010, and 2009;

Consolidated Statements of Comprehensive Income for each of the three years ended December 31, 2011, 2010, and 2009;

Consolidated Balance Sheets at December 31, 2011 and December 31, 2010;

Consolidated Statements of Cash Flows for each of the three years ended December 31, 2011, 2010, and 2009;

Consolidated Statements of Stockholders Equity for each of the three years ended December 31, 2011, 2010, and 2009; and

Notes to the Consolidated Financial Statements.

2. Financial Statement Schedules:

Report of Independent Registered Public Accounting Firm; and

Schedule II Valuation and Qualifying Accounts.

All other schedules are omitted, because they are not required, are inapplicable, or the information is otherwise shown in the financial statements or notes thereto.

3. Exhibits

Exhibit 1.1 Underwriting Agreement entered into by Chesapeake Utilities Corporation and Robert W. Baird & Co. Incorporated and A.G. Edwards & Sons, Inc., on November 15, 2006 relating to the sale and issuance of 600,300 shares of Chesapeake s common stock, is incorporated herein by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed November 16,

	2006, File No. 001-11590.
Exhibit 2.1	Agreement and Plan of Merger between Chesapeake Utilities Corporation and Florida Public Utilities Company dated April 17, 2009, is incorporated herein by reference to Exhibit 2.1 of our Current Report on Form 8-K, filed April 20, 2009, File No. 001-11590.
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 April 7, 2010, are incorporated herein by reference to Exhibit 3 of the Company s Current Report on Form 8-K, filed April 13, 2010, File No. 001-11590.
Exhibit 4.1	Form of Indenture between Chesapeake and Boatmen s Trust Company, Trustee, with respect to the 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.

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Exhibit 4.2	Note Purchase Agreement, entered into by the Company on October 2, 1995, pursuant to which Chesapeake privately placed $10 million of its 6.91% Senior Notes, paid off in 2010, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 4.3	Note Purchase Agreement, entered into by Chesapeake on December 15, 1997, pursuant to which Chesapeake privately placed $10 million of its 6.85% Senior Notes due in 2012, is incorporated by reference to Exhibit 4.3 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 4.4	Note Purchase Agreement entered into by Chesapeake on December 27, 2000, pursuant to which Chesapeake privately placed $20 million of its 7.83% Senior Notes, due in 2015, is incorporated by reference to Exhibit 4.4 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 4.5	Note Agreement entered into by Chesapeake on October 31, 2002, pursuant to which Chesapeake privately placed $30 million of its 6.64% Senior Notes, due in 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 4.6	Note Agreement entered into by Chesapeake on October 18, 2005, pursuant to which Chesapeake, on October 12, 2006, privately placed $20 million of its 5.5% Senior Notes, due in 2020, with Prudential Investment Management, Inc., 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 4.7	Note Agreement entered into by Chesapeake on October 31, 2008, pursuant to which Chesapeake, on October 31, 2008, privately placed $30 million of its 5.93% Senior Notes, due in 2023, with General American Life Insurance Company and New England Life Insurance Company, is incorporated by reference to Exhibit 4.7 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 4.8	Form of Indenture of Mortgage and Deed of Trust between Florida Public Utilities Company and the trustee, dated September 1, 1942 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 entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on April 12, 2011, 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 entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on December 1, 2009, pursuant to which Chesapeake Utilities Corporation, on December 1, 2009 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	Fifteenth Supplemental Indenture entered into by Florida Public Utilities Company on November 1, 2001, pursuant to which Florida Public Utilities Company, on November 1, 2001, privately placed $14,000,000 of its 4.90% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(c) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.

Exhibit 4.12	Fourteenth Supplemental Indenture entered into by Florida Public Utilities Company on September 1, 2001, pursuant to which Florida Public Utilities Company, on September 1, 2001, privately placed $15,000,000 of its 6.85% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(b) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.
Exhibit 4.13	Thirteenth Supplemental Indenture entered into by Florida Public Utilities Company on 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 4.14	Twelfth Supplemental Indenture entered into by Florida Public Utilities on May 1, 1988, pursuant to which Florida Public Utilities Company, on May 1, 1988, privately placed $10,000,000 and $5,000,000 of its 9.57% First Mortgage Bonds and 10.03% First Mortgage Bonds, respectively, are 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, 1988.
Exhibit 4.15	Term Note Agreement entered into by Chesapeake Utilities Corporation on March 16, 2010, pursuant to the $29 million credit facility with PNC Bank, N.A., is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
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, adopted in 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, adopted in 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, adopted in 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 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 10.6*	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 10.7	Consulting Agreement dated January 3, 2011, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.8 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.8*	Executive Employment Agreement dated January 14, 2011, by and 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 10.9*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.

Exhibit 10.10*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.11*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Joseph Cummiskey, is incorporated herein by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.12*	Executive Employment Agreement dated March 3, 2011, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.13 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.13*	Amendment to Executive Employment Agreement, effective January 1, 2012, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is filed herewith.
Exhibit 10.14*	Form of Performance Share Agreement effective January 7, 2009 for the period 2009 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.26 on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.15*	Form of Performance Share Agreement effective January 6, 2010 for the period 2010 to 2012, 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 Joseph Cummiskey is incorporated herein by reference to Exhibit 10.24 on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 10.16*	Performance Share Agreement dated January 20, 2010 for the period 2010 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Joseph Cummiskey is incorporated herein by reference to Exhibit 10.24 on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 10.17*	Form of Performance Share Agreement effective January 14, 2011 for the period 2011 to 2013, 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, Joseph Cummiskey, and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
Exhibit 10.18*	Form of Performance Share Agreement effective January 14, 2011 for the period 2011 to 2012, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.28 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.19*	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 10.20*	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 10.21*	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.

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Exhibit 10.22*	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 10.23	Amended and Restated Electric Service Contract between Florida Public Utilities Company and JEA dated November 6, 2008, is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company s Current Report on Form 8-K, filed on November 6, 2008, File No. 001-10908.
Exhibit 10.24	Networking Operating Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.25	Network Integration Transmission Service Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.4 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.26	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2016 (Contract No. 107033), is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.27	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to March 2022 (Contract No. 107034), is incorporated herein by reference to Exhibit 10.2 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.28	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2022 (Contract No. 107035), is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.29	Precedent Agreement between Chesapeake Utilities Corporation and Texas Eastern Transmission LP, dated April 8, 2010 is incorporated herein by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
Exhibit 10.30	Form of Franchise Agreement between Florida Public Utilities Company and the city of Marianna, effective February 1, 2010, is incorporated herein by reference to Exhibit 10.41 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-1068.

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Exhibit 10.31	Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, dated December 28, 2006, effective January 1, 2008 is hereby incorporated herein by reference to Exhibit 10(s) on Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2006, File No. 001-10608.
Exhibit 10.32	Amendment to Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, effective January 25, 2011, is incorporated herein by reference to Exhibit 10.43 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-10608.
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.
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 7, 2012, 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 7, 2012, 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 7, 2012, 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 7, 2012, is filed herewith.
Exhibit 101. INS**	XBRL Instance Document
Exhibit 101. SCH**	XBRL Taxonomy Extension Schema Document
Exhibit 101. CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
Exhibit 101. DEF**	XBRL Taxonomy Extension Definition Linkbase Document
Exhibit 101. LAB**	XBRL Taxonomy Extension Label Linkbase Document
Exhibit 101. PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Management contract or compensatory plan or agreement.

** XBRL (Extensible Business Reporting Language) information is furnished and not filed for purposes of Section 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934. In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 of this Annual Report on Form 10-K shall not be subject to the liability of Section 18 of the Securities Exchange Act of 1934 and shall not be part of any registration statement or other document filed under the Securities Act of 1933 or the Securities Exchange Act of 1934, except as shall be expressly set forth by specific reference in such filing.

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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 7, 2012

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: February 29, 2012

/s/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director

Date: March 7, 2012

/s/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
Date: March 7, 2012

/s/ EUGENE H. BAYARD,ESQ
Eugene H. Bayard, Director
Date: February 29, 2012

/s/ RICHARD BERNSTEIN
Richard Bernstein, Director
Date: February 29, 2012

/s/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
Date: March 5, 2012

/s/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
Date: February 29, 2012

/s/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
Date: February 29, 2012

/s/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
Date: February 29, 2012

/s/ J. PETER MARTIN
J. Peter Martin, Director
Date: February 29, 2012

/s/ JOSEPH E. MOORE, ESQ
Joseph E. Moore, Esq., Director
Date: February 29, 2012

/s/ CALVERT A. MORGAN, JR
Calvert A. Morgan, Jr., Director
Date: February 29, 2012

/s/ DIANNA F. MORGAN
Dianna F. Morgan, Director
Date: February 29, 2012

/s/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Vice Chairman of the Board and Director
Date: February 29, 2012

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 7, 2012 relating to the consolidated financial statements of Chesapeake Utilities Corporation as of December 31, 2011 and 2010 and for each of the years in the three-year period ended December 31, 2011, 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 Chesapeake Utilities Corporation s management. Our responsibility is to express an opinion on this 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/ ParenteBeard LLC
ParenteBeard LLC

Malvern, Pennsylvania

March 7, 2012

Chesapeake Utilities Corporation and Subsidiaries

Schedule Valuation and Qualifying Accounts

Schedule II

Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts (1)	Deductions (2)	Balance at End of Year
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
(In thousands)					
2011	**$ 1,194**	**$ 1,157**	**$ 293**	**$ (1,554)**	**$ 1,090**
2010	$ 1,609	$ 1,129	$ 181	$ (1,725)	$ 1,194
2009	$ 1,159	$ 1,138	$ 616	$ (1,304)	$ 1,609

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