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

909 Silver Lake Boulevard, Dover, Delaware 19904

(Address of principal executive offices, including zip code)

302-734-6799

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:

8.25% Convertible Debentures Due 2014

(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨. No 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.

(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.

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.

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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.

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.

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	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

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.

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.

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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.

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, *(in thousands)*	2011	2010	Increase (decrease)	2010	2009	Increase (decrease)
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.

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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	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
(in thousands)					
Long-term debt [1]	$ 8,196	$ 20,527	$ 18,273	$ 71,546	$ 118,542