CHESAPEAKE UTILITIES CORP
Form 10-K
March 08, 2010

Table of Contents

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, 2009
Commission File Number: 001-11590

Chesapeake Utilities Corporation
(Exact name of registrant as specified in its charter)

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

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including zip code)
302-734-6799
(Registrant s telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock par value per share $.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 o. No þ.

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 o. No þ.

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 þ. No o.

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 o. No o.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. þ

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 o	Accelerated filer þ	Non-accelerated filer o	Smaller Reporting Company o

Indicate by a check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o. No þ.
The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2009, 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 $223.5 million.
As of February 28, 2010, 9,436,558 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2010 Annual Meeting of Stockholders are incorporated by reference in Part III.

Chesapeake Utilities Corporation

Form 10-K
YEAR ENDED DECEMBER 31, 2009
TABLE OF CONTENTS

Table of Contents

GLOSSARY OF KEY TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

Subsidiaries of Chesapeake Utilities Corporation

BravePoint	BravePoint, Inc., a wholly-owned subsidiary of Chesapeake Services Company, which is a wholly-owned subsidiary of Chesapeake
Chesapeake	The Registrant, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure
Company	The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries, as appropriate in the context of the disclosure
ESNG	Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake
FPU	Florida Public Utilities Company, a new wholly-owned subsidiary of Chesapeake, effective October 28, 2009
OnSight	Chesapeake OnSight Services, LLC, a wholly-owned subsidiary of Chesapeake
PESCO	Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake
PIPECO	Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake
Sharp	Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake and Sharp s subsidiary, Sharpgas, Inc.
Xeron	Xeron, Inc., a wholly-owned subsidiary of Chesapeake

Regulatory Agencies

Delaware PSC	Delaware Public Service Commission
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
Florida PSC	Florida Public Service Commission
IRS	Internal Revenue Service
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Table of Contents

Other

AOCI	Accumulated Other Comprehensive Income
DSCP	Directors Stock Compensation Plan
GSR	Gas sales service rates
HDD	Heating degree-days
Mcf	Thousand Cubic Feet
MWH	Megawatt Hour
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
PIP	Performance Incentive Plan
S&P 500 Index	Standard & Poor s 500 Index
SFAS	Statement of Financial Accounting Standards

Accounting Standards

ASC	FASB Accounting Standards Codification TM(Codification)
ASU	FASB Accounting Standards Update
FSP	Financial Accounting Standards Board Staff Position
GAAP	Generally Accepted Accounting Principles

Table of Contents

Part I

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

Safe Harbor for Forward-Looking Statements

We make statements in this 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. You can typically identify forward-looking statements by the use of forward-looking words, such as project, believe, expect, anticipate, intend, plan, estimate, continue, potential, forecast or other similar words, or future or cond such as may, will, should, would or could. These statements represent our intentions, plans, expectations, assum 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 Risks 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;
- industrial, commercial and residential growth or contraction in our 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; and

the effect of competition on our businesses.

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 in 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 (ESNG) and Peninsula Pipeline Company, Inc. (PIPECO), respectively. Our unregulated businesses include 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 propane wholesale marketing operation through Xeron, Inc. (Xeron). We also have an advance information services subsidiary, BravePoint, Inc. (BravePoint).

(b) Operating Segments

As a result of the merger with FPU, we changed our operating segments to better align with how the chief operating decision maker (our Chief Executive Officer) views the various operations of the Company. Our three operating segments are now composed of the following:

Regulated Energy. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the Public Service Commission (PSC) having jurisdiction in each operating territory or by the Federal Energy Regulatory Commission (FERC) in the case of ESNG.

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 and net property, plant and equipment:

(in thousands)	**Operating Income**		**Net Property, Plant & Equipment**	
Regulated Energy	$ 26,900	80%	$ 387,022	89%
Unregulated Energy	8,158	24%	37,900	8%
Other	(1,322)	-4%	11,506	3%
Total	$ 33,736	100%	$ 436,428	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.

(i) Regulated Energy

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

Natural Gas Distribution

Our Delaware and Maryland natural gas distribution divisions serve 51,736 residential and commercial customers and 155 industrial customers in central and southern Delaware and Maryland s Eastern Shore. For the year ended December 31, 2009, operating revenues and deliveries by customer class for our Delaware and Maryland distribution divisions were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Residential	$ 51,309	58%	2,747,162	36%
Commercial	31,942	36%	2,693,724	35%
Industrial	3,696	4%	1,827,153	24%
Subtotal	86,947	98%	7,268,039	95%
Interruptible	977	1%	373,825	5%
Other (1)	1,291	1%		
Total	$ 89,215	100%	7,641,864	100%

(1) Operating revenues from Other sources include unbilled revenue, rental of gas properties, and other miscellaneous charges.

Chesapeake s Florida natural gas distribution division provides unbundled natural gas distribution services (the delivery of natural gas separated from the sale of the commodity) to 13,268 residential and 1,176 commercial and industrial customers in 14 counties in Florida. For the year ended December 31, 2009, operating revenues and deliveries by customer class for our Florida distribution division were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Residential	$ 3,682	30%	318,420	2%
Commercial	3,043	25%	1,151,071	8%
Industrial	4,260	34%	13,271,503	90%
Other(1)	1,377	11%		
Total	$ 12,362	100%	14,740,994	100%

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

Table of Contents

Our recent merger with FPU provides 51,536 additional residential, commercial and industrial natural gas distribution customers in seven counties in Florida, which have significantly expanded our existing natural gas distribution operations in Florida. For the period from the merger closing (October 28, 2009) to December 31, 2009, operating revenues and deliveries by customer class for these new customers added through the merger were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Residential	$ 3,028	27%	180,572	16%
Commercial	4,722	43%	496,183	45%
Industrial	1,346	12%	320,680	29%
Subtotal	9,096	82%	997,435	90%
Other[(1)]	2,045	18%	111,742	10%
Total	$ 11,141	100%	1,109,177	100%

(1) Operating revenues from Other sources include unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges and adjustments for pass-through taxes.

FPU s total natural gas deliveries in the full calendar year 2009, including deliveries for the period prior to the merger, were 1,157,100 Mcfs, 2,942,800 Mcfs and 1,784,500 Mcfs for residential, commercial and industrial customers, respectively.

Electric Distribution

Electric distribution is a new regulated energy business added to the Company as a result of the FPU merger. FPU distributes electricity to 31,030 customers in five counties in northeast and northwest Florida. For the period from the merger closing (October 28, 2009) to December 31, 2009, operating revenues and deliveries by customer class for FPU s electric distribution services were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(MWHs)*	
Residential	$ 6,140	50%	43,435	41%
Commercial	6,273	52%	50,033	47%
Industrial	1,004	8%	9,700	10%
Subtotal	13,417	110%	103,168	98%
Other[(1)]	(1,174)	-10%	2,572	2%

Total	$	12,243	100%	105,740	100%

(1) Operating revenues from Other sources include unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges and adjustments for pass-through taxes.

FPU s total deliveries of electricity in the full calendar year 2009, including deliveries for the period prior to the merger, were 316,306 MWHs, 316,412 MWHs and 64,950 MWHs for residential, commercial and industrial customers, respectively.

Table of Contents

Natural Gas Transmission

ESNG operates a 384-mile interstate pipeline system that transports natural gas from various points in Pennsylvania to Chesapeake s 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. ESNG also provides swing transportation service and contract storage services. For the year ended December 31, 2009, operating revenues and deliveries by customer class for ESNG were as follows:

	Operating Revenues (in thousands)		Deliveries (Mcfs)	
Local distribution companies	$ 19,699	76%	9,941,436	38%
Industrial	4,907	19%	14,471,109	55%
Commercial	1,336	5%	1,809,970	7%
Other [1]	35	0%		
Subtotal	25,977	100%	26,222,515	100%
Less: affiliated local distribution companies	(12,709)	(49)%	(5,578,918)	(21)%
Total non-affiliated	$ 13,268	51%	20,643,597	79%

(1) Operating revenues from Other sources are from rental of gas properties.

In 2005, we formed PIPECO to operate an intrastate pipeline to provide natural gas transportation services to industrial customers in Florida. In December 2007, the Florida Public Service Commission (Florida PSC) approved PIPECO s natural gas transmission pipeline tariff, which established its operating rules and regulations. In January 2009, PIPECO began providing natural gas transmission services to a customer for a period of 20 years at a fixed monthly charge, through an 8-mile pipeline located in Suwanee County, Florida, which PIPECO owns. For the year ended December 31, 2009, PIPECO had $264,000 in operating revenues under the contract.

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

Our Delaware and Maryland natural gas distribution divisions have both firm and interruptible transportation service contracts with four interstate open access pipeline companies, including the ESNG pipeline. These divisions are directly interconnected with the ESNG pipeline, and have contracts with interstate pipelines upstream of ESNG, including Transcontinental Gas Pipe Line Corporation (Transco), Columbia Gas Transmission Corporation (Columbia) and Columbia Gulf Transmission Company (Gulf). The Transco and Columbia pipelines are directly interconnected with the ESNG pipeline. The Gulf pipeline is directly interconnected with the Columbia pipeline and indirectly interconnected with the ESNG pipeline. None of the upstream pipelines is owned or operated by an affiliate of the Company. The Delaware and Maryland divisions use their firm transportation supply resources to meet a significant percentage of their projected demand requirements and they purchase 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 ESNG. These divisions also have the capability to use propane-air peak-shaving to supplement or displace the spot market purchases.

Table of Contents

The following table shows the firm transmission and storage capacity that the Delaware and Maryland divisions currently have under contract with ESNG and pipelines upstream of the ESNG pipeline, including the respective contract expiration dates.

Delaware

Pipeline	Firm transmission capacity maximum peak-day daily deliverability (Mcfs)	Firm storage capacity maximum peak-day daily withdrawal (Mcfs)	Expiration
Transco	20,699	6,190	Various dates between 2010 and 2028
Columbia	17,836	7,946	Various dates between 2011 and 2020
Gulf	850		Expires in 2014
ESNG	63,482	4,006	Various dates between 2010 and 2024

Maryland

Pipeline	Firm transmission capacity maximum peak-day daily deliverability (Mcfs)	Firm storage capacity maximum peak-day daily withdrawal (Mcfs)	Expiration
Transco	5,921	2,373	Various dates between 2010 and 2012
Columbia	6,473	3,539	Various dates between 2011 and 2018
Gulf	570		Expires in 2014
ESNG	19,834	2,228	Various dates between 2010 and 2023

The Delaware and Maryland divisions currently have contracts with several suppliers for the purchase of firm natural gas supply in the amount of their capacities on the Transco and Columbia pipelines. They also have contracts for firm peaking gas supplies to be delivered to their systems in order to meet the differential between their capacities on the ESNG pipeline and capacities on pipelines upstream of ESNG. These supply contracts provide a maximum firm daily entitlement of 13,237 Mcfs and 2,029 Mcfs for the Delaware and Maryland divisions, respectively, delivered on the Transco, Columbia, and/or Gulf systems to ESNG for redelivery to these divisions under firm transmission contracts. These gas supply contracts have various expiration dates, and quantities may vary from day to day and month to month.

Chesapeake s Florida natural gas distribution division has firm transmission 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, including PESCO. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

Contracts by Chesapeake s Florida natural gas distribution division with FGT include: (a) a contract, which expires on July 31, 2010, for daily firm transmission capacity of 22,901 Mcfs for the months of November through April, capacity of 19,594 Mcfs for the months of May through September, and 21,524 Mcfs for October; and (b) a contract for daily firm transmission capacity of 974 Mcfs daily, which expires in 2015. Chesapeake s contract with Gulfstream is for daily firm transmission capacity of 9,737 Mcfs and expires in 2022.

Table of Contents

FPU has firm transmission service contracts with FGT and firm transportation contracts with Florida City Gas (FCG) and Indiantown Gas Company (IGC). The additional contracts with FGT include (a) a contract which expires on July 2020, for daily firm transmission capacity of 26,500 Mcfs for the months of November through March, 22,411 Mcfs for the month of April, 9,211 Mcfs for the months of May through September and 9,314 Mcfs for the month of October; (b) a contract which expires in 2015 for daily firm transmission capacity of 10,286 Mcfs for the months of November through April and 4,360 Mcfs for the months of May through October; (c) a contract which expires in July 2020 for daily firm transmission capacity of 2,147 Mcfs for the months of November through March, 1,745 Mcfs for the month of April, 470 Mcfs for the months of May through September, and 896 Mcfs for the month of October; and (d) a contract for daily firm transmission capacity of 1,774 Mcfs with various partial expiration dates between 2016 and 2023. The contract with FCG, which expires in 2013, provides daily firm transportation capacity of 292 Mcfs on its Pioneer Pipeline. The contract with IGC, which expires in 2016, provides daily firm transportation capacity of 487 Mcfs on its distribution system.

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

Natural Gas Transmission

ESNG has three contracts with Transco for a total of 7,045 Mcfs of firm peak day storage entitlements and total storage capacity of 278,264 Mcfs, each of which expires in 2013. ESNG has retained these firm storage services in order to provide swing transportation service and firm storage service to those customers that have requested such service(s).

Electric Distribution

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

<u>Competition</u>

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

<u>Rates and Regulation</u>

Our natural gas and electric distribution operations are subject to regulation by the Delaware, Maryland and Florida PSCs with respect to various aspects of their business, including rates for sales and transportation to all customers in each respective jurisdiction. All of our firm distribution sales rates are subject to fuel cost recovery mechanisms, which match revenues with 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 regulatory authority having jurisdiction.

ESNG is subject to regulation as an interstate pipeline by the FERC, which regulates the terms and conditions of service and the rates ESNG can charge for its transmission and storage services. PIPECO is subject to regulation by the Florida PSC.

Table of Contents

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 Current Rates	Allowed Rate of 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 Electric	Florida PSC	5/22/2008	11.00% (1)
ESNG	FERC	9/1/2007	13.60% (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.

PIPECO, 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 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Rate Filings and Other Regulatory Activities.

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 sold and delivered. Specifically, customer demand substantially increases during the winter months, when natural gas is used for heating. Accordingly, the 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 use of natural gas, while sustained colder-than-normal temperatures will tend to increase 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 below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day. 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 Public Service Commission (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.

Table of Contents

(ii) Unregulated Energy

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 2,123 customers in Florida and 11 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, 2009, PESCO s operating revenues and deliveries were as follows:

	Operating Revenues *(in thousands)*			Deliveries *(Mcfs)*	
Florida	$	41,117	72%	7,066,144	71%
Delmarva		16,386	28%	2,818,844	29%
Total	$	57,503	100%	9,884,988	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 Mcfs, and expire in May of 2010. 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.

Included in PESCO s operating revenue on the Delmarva Peninsula for 2009 was approximately $10.6 million of various natural gas spot sales and services to Valero Energy Corporation (Valero) for its Delaware City refinery operation. We previously reported on November 25, 2009 in a Form 8-K that Valero announced its intention to permanently shut down its Delaware City refinery. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts; nor do we anticipate sales to Valero in the future.

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.

Table of Contents

Sharp, our propane distribution subsidiary, serves 33,088 customers throughout Delaware, the Eastern Shore of Maryland and Virginia and southeastern Pennsylvania. Sharp s Florida operation offers propane distribution services to 1,941 customers in parts of Florida. After the merger with FPU, 1,642 customers previously served by Sharp s Florida propane distribution operation are now being served by FPU s propane distribution operation in an effort to integrate operations. For the year ended December 31, 2009, operating revenues and total gallons sold by Sharp s Delmarva and Florida propane distribution operations were as follows:

	Operating Revenues (in thousands)			Total Gallons Sold (in thousands)	
Delmarva	$	54,850	96%	30,635	97%
Florida		2,357	4%	853	3%
Total	$	57,207	100%	31,488	100%

FPU has 13,651 propane distribution customers, including the customers previously served by Sharp s propane distribution operation in Florida as previously discussed, which increased our propane customer base in Florida. For the period from the merger closing (on October 28, 2009) to December 31, 2009, operating revenue and total gallons delivered to these new customers were $3.0 million and 1.1 million gallons. FPU s total propane deliveries in the full calendar year 2009, including the deliveries for the period prior to the merger, were 5.7 million gallons.

Propane Wholesale Marketing.

Xeron, our propane wholesale marketing operation, 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 the propane wholesale price volatility and supply levels. In 2009, Xeron had operating revenues totaling approximately $2.3 million, net of the associated cost of propane sold. For further discussion on Xeron s trading and 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. 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 3.0 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 (DOT) 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.

Advanced Information Services

Our advanced information services subsidiary, BravePoint, is headquartered in Norcross, Georgia, and provides domestic and 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 registered in Delaware.

(c) Other 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, 2009, we had a total of 757 employees, including 332 employees who joined the Company as a result of the recent merger with FPU, 162 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 2010.

(iii) Financial Information about Geographic Areas

All of our material operations, customers, and assets occur and 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 on the operation of 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.

Table of Contents

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. Each of these documents also is available on our Internet website or may be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Blvd., Dover, DE 19904.

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

Our Chief Executive Officer certified to the NYSE on June 1, 2009 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 financial, operational, regulatory and legal, and environmental risk factors that may affect the operations and/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

The anticipated benefits of the merger with FPU may not be realized.

We entered into the merger with FPU with the expectation that the merger would result in various benefits, including, among other things, synergies, cost savings and operating efficiencies. Achieving these synergies, cost savings and operating efficiencies cannot be assured and failure to achieve these benefits will adversely affect expected future performance of the Company. In addition, the regulatory agencies that have jurisdiction over our regulated energy businesses and operations may require us to pass on some, or all, of the achieved cost savings to ratepayers.

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 from operations, we may incur additional indebtedness to finance our growth. The turmoil experienced in the credit markets in 2008 and 2009 and its potential impact on the liquidity of major financial institutions may have an adverse effect on our customers and our ability to fund our business strategy through borrowings, under either existing or newly created arrangements in the public or private markets on terms we believe to be reasonable. 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.

Table of Contents

Unsound financial institutions could adversely affect the Company.

Our businesses have exposure to different industries and counterparties, and may periodically execute transactions with counterparties in the financial services industry, including brokers and dealers, commercial banks, investment banks and other institutional clients. These transactions may expose us to credit risk in the event of default of a counterparty or client. There can be no assurance that any such losses or impairments would not materially and adversely affect our businesses and results of operations.

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.

Debt covenant obligations, if triggered, may affect our financial condition.

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.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy, together with increased unemployment, mortgage and other credit defaults and significant decreases in the values of homes and investment assets, have adversely affected the financial resources of many domestic households. It is unclear whether governmental responses to these conditions will be successful in lessening the severity or duration of the current recession. As a result, our customers may use less natural gas, electricity or propane and it may become more difficult for them to pay their bills. This may slow collections and lead to higher than normal levels of accounts receivable, which in turn, could increase our financing requirements and result in higher bad debt expense.

Further changes in economic conditions and interest rates may adversely affect our results of operations and cash flows.

A continued downturn in the economies of the regions in which we operate might adversely affect our ability to increase our customer base and cash flows at historical rates. Further, 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, and to temporarily finance capital expenditures.

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

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for regulated operations and closely monitor the returns of our unregulated operations. There can be no assurance that we will be able to obtain adequate and timely rate increases to offset the effects of inflation. 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 operation and propane wholesale marketing operation are subject to market risks beyond their control, including market liquidity and commodity price volatility. Although we maintain a risk management policy, 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 Xeron 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 have credit risk and credit requirements that may 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. These subsidiaries are also 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 the Company declines, then the cost of credit available to these subsidiaries could increase. If credit is not available, or if credit is more costly, our results of operations, cash flows and financial condition may be adversely affected.

Current market conditions have had an adverse impact on the return on plan assets for our pension plans, which may require significant additional funding and adversely affect the Company s cash flows.

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. As a result of the extreme volatility and disruption in the domestic and international equity and bond markets in recent years, the asset values of Chesapeake s and FPU s pension plans declined by $2.4 million and $2.8 million, respectively, 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 may necessitate accelerated funding of the plans in the future to meet minimum federal government requirements. Downward pressure on the asset values of our pension plans may require us to 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

We may be unable to successfully integrate operations after the merger.

The merger between Chesapeake and FPU involves the integration of two companies that have previously operated independently. The difficulties of combining the companies operations include, among other things:

- the necessity of coordinating geographically separated organizations, systems and facilities;
- combining the best practices of the two companies, including operations, financial and administrative functions; and
- integrating personnel with diverse business backgrounds and different contractual terms and conditions of employment.

Table of Contents

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of one or more of our businesses and the loss of key personnel. We will be subject to employee workforce factors, including loss of employees, availability of qualified personnel, collective bargaining agreements with unions and work stoppages that could affect our business and financial condition. Our management team comprised of key personnel from both Chesapeake and FPU has dedicated substantial efforts to integrating the businesses. Such efforts could divert management s focus and resources from other strategic opportunities during the integration process. The diversion of management s attention and any delays or difficulties encountered in connection with the merger and the integration of the two companies operations could result in the disruption of our ongoing businesses or inconsistencies in standards, controls, procedures and policies that adversely affect our ability to maintain relationships with customers, suppliers, employees and others with whom we have business dealings.

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 sold and delivered. 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. In addition, hurricanes or other extreme weather conditions could damage production or transportation facilities, which could result in decreased supplies of natural gas, propane and electricity, increased supply costs and higher prices for customers.

Our electric operations, while generally less weather sensitive than natural gas and propane sales, are also affected by variations in general weather conditions and unusually severe weather.

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

Natural gas, electricity and propane 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.

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

Our natural gas distribution and marketing operations, electric distribution operation and propane operations have entered into various agreements with suppliers to purchase natural gas, electricity and propane to serve their 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.

We rely on having access to interstate natural gas pipelines transmission and storage capacity and electric transmission capacity; a substantial disruption or lack of growth in these services 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 both sufficient natural gas supplies, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate delivery 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, all of FPU s natural gas is transported through one pipeline system. Any interruption to that system could adversely affect our ability to meet the demands of FPU s customers and our earnings.

Table of Contents

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 and other fuels can significantly increase the cost of electricity billed to our electric 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/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. 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 3.0 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 unit 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 unit price of the propane that we purchase can change rapidly over a short period of time. The 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 U.S. generally accepted accounting principles (GAAP) if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

Operating events affecting public safety and the reliability our natural gas and electric distribution systems could adversely affect the results of operations, cash flows and financial condition.

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

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.

Table of Contents

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. 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 will compete against 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 operation 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 a risk management policy 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.

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 fuel sources. Slowdowns in these markets have and will continue to 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 facilities and operations could be targets of acts of terrorism.

Our natural gas and electric distribution, natural gas transmission and propane storage facilities may be targets of terrorist activities that could disrupt our ability to meet customer requirements. Terrorist attacks may also disrupt capital markets and our ability to raise capital. A terrorist attack on our facilities, or those of our suppliers or customers, could result in a significant decrease in revenues or a significant increase in repair costs, which could adversely affect our results of operations, financial position and cash flows.

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 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/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), a pandemic 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 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. The occurrence of any of these events could adversely affect our results of operations, cash flows and financial condition.

Our regulated energy business will 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.

Table of Contents

Regulatory and Legal Risks

Regulation of the Company, 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. ESNG is regulated by the FERC. These commissions 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.

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. As a result, we are sometimes a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance policies with insurers in the amount of $50 million covering general liabilities of the Company, 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 have recorded significant amounts of goodwill and regulatory assets prior to obtaining a rate order. An adverse outcome could result in an impairment of those assets.

The merger with FPU resulted in approximately $33.4 million in purchase premium which is currently recorded as goodwill. We also incurred approximately $3.0 million in merger-related costs, $1.5 million of which was deferred as a regulatory asset. We will be seeking regulatory approval to include these amounts in future rates in Florida. Other utilities in Florida, including Chesapeake and FPU in the past, have been successful in recovering similar costs by demonstrating benefits to customers attributable to the business combination. The ultimate outcome of such regulatory proceedings will depend on various factors, including but not limited to, our ability to achieve the anticipated benefits of the merger, the future regulatory environment in Florida and the future results of our Florida regulated operations. If we are not successful in obtaining regulatory approval to recover these costs in future rates, we will be required to perform impairment tests of goodwill and regulatory assets, the results of which could be an impairment of all or part of the goodwill and/or regulatory assets in the future.

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 current and former operating sites, including former manufactured gas plant (MGP) sites that we have acquired from third-parties. 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.

Table of Contents

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.

We may be exposed to certain regulatory and financial risks related to climate change.

Climate change is receiving ever increasing attention from scientists, legislators and regulators alike. The debate is ongoing as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs, including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

- result in increased costs associated with our operations;
- increase other costs to our business;
- affect the demand for natural gas, electricity and propane; and
- impact the prices we charge our customers.

Any action taken by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows.

Pending environmental matters, particularly with respect to FPU s site in West Palm Beach, Florida, may have a materially adverse effect on the 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 the Company has certain exposures at six former MGP sites. Those sites are located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the Maryland Department of the Environment (MDE) regarding a seventh former MGP site located in Cambridge, Maryland. The Key West, Pensacola, Sanford and West Palm Beach sites are related to FPU, for which we assumed any existing and future contingencies in the merger with FPU.

Pursuant to a consent order that FPU entered into with the Florida Department of Environmental Protection (the FDEP) prior to our merger with FPU, FPU is obligated to assess and remediate environmental impacts to soil and groundwater resulting from operation of the former West Palm Beach MGP. Following completion of the assessment task, FPU retained a consultant to perform a feasibility study to evaluate appropriate remedies for the site to respond to the reported environmental impacts. The feasibility study was performed and subsequently revised as a result of additional testing conducted at the site and extensive discussions with FDEP. The revised feasibility study evaluates several alternative remedies for the site. Discussions with FDEP are continuing, regarding selection of an appropriate remedy for the West Palm Beach site. Our current estimate of total remediation costs and expenses, including legal and consulting expenses, for the West Palm Beach site based on the likely remedy we believe will be approved by FDEP is between $7.8 million and $19.4 million; however, actual costs may be higher or lower than such range based upon the final remedy required by FDEP.

As of December 31, 2009, we had recorded $531,000 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 $1.7 million in assets for future recovery of environmental costs to be received from our customers through our approved rates. As of December 31, 2009, we had recorded approximately $12.3 million in environmental liabilities related to FPU s MGP sites in Florida, primarily related to the West Palm Beach site. Such amount represents our estimate as of December 31, 2009, of the future costs associated with those sites, although FPU is approved to recover its environmental costs up to $14.0 million from insurance and customers through approved rates. Of the approximately $12.3 million recorded as environmental liabilities related to FPU s MGP sites in Florida as of December 31, 2009, we have recovered approximately $5.7 million of environmental costs from insurance and customers through rates, and have recorded approximately $6.6 million in assets for future recovery of environmental costs to be received from FPU s customers through approved rates.

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 described above.

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; Lecanto, Virginia; and West Palm Beach, DeBary, Inglis, Marianna, Lantana, Lauderhill, Fernandina Beach and Winter Haven, Florida. We rent office space in Dover, Ocean View, and South Bethany, Delaware; Jupiter, Fernandina 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 over 1,102 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 operations, including Chesapeake s Florida division and FPU in its service areas, own 2,404 miles of natural gas distribution mains (and related equipment). Additionally, 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

ESNG owns and operates approximately 384 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Pennsylvania; Daleville, Pennsylvania; and Hockessin, Delaware, to approximately 80 delivery points in southeastern Pennsylvania, Delaware and the Eastern Shore of Maryland.

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

(d) Electric Distribution

The Company s electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 1,125 miles of electric distribution line located in northeast and northwest Florida.

Table of Contents

(e) Propane Distribution and Wholesale Marketing

Our Delmarva-based propane distribution operation owns bulk propane storage facilities, with an aggregate capacity of approximately 2.4 million gallons, at 42 plant facilities in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by the Company. Our Florida-based propane distribution operation owns 21 bulk propane storage facilities with a total capacity of 642,000 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: DeBary, Inglis, Marianna, Lantana, Lauderhill and Fernandina, Florida. FPU s natural gas distribution operation owns 1,637 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 1,125 miles of electric distribution line located in northeast and northwest Florida. FPU s propane distribution operation owns 18 bulk propane storage facilities with a total capacity of 576,000 gallons located in south and central Florida.

Item 3. Legal Proceedings.

(a) General

The Company and its subsidiaries are currently involved in various legal actions and claims arising in the normal course of business. The Company is 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 the Company s consolidated financial position and results of operations.

(b) Environmental

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

Item 4. Submission of Matters to a Vote of Security Holders.

A special meeting of the shareholders of the Company was held on October 22, 2009, to consider and vote upon the following proposals:

(1) A proposal related to adoption of the merger agreement and approval of the merger with Florida Public Utilities Company;

(2) A proposal relating to the issuance of Chesapeake common stock in the merger; and

(3) A proposal to approve adjournments or postponements of the special meeting, if necessary, to permit further solicitation of proxies if there are not sufficient votes at the end of the time in the special meeting to approve the above proposals.

The proposals were approved as follows:

	Votes For	Votes Against or Withheld	Abstentions
Adoption of the merger agreement and approval of the merger	5,186,617	85,243	27,204
Issuance of Chesapeake common stock in the merger	5,186,617	85,243	27,204
Approve adjournment or postponement	4,846,740	411,960	40,365

There were no broker non-votes.

Table of Contents

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
John R. Schimkaitis	62	Vice Chairman and Chief Executive Officer
Michael P. McMasters	51	President and Chief Operating Officer
Beth W. Cooper	43	Senior Vice President and Chief Financial Officer
Stephen C. Thompson	49	Senior Vice President and President, ESNG
Joseph Cummiskey	38	Vice President and President, PESCO

John R. Schimkaitis is Vice Chairman and Chief Executive Officer of Chesapeake and its subsidiaries. Mr. Schimkaitis assumed the role of Chief Executive Officer on January 1, 1999. Mr. Schimkaitis previously served as President, Chief Operating Officer, Executive Vice President, Senior Vice President, Chief Financial Officer, Vice President, Treasurer, Assistant Treasurer and Assistant Secretary of Chesapeake.

Michael P. McMasters is President and Chief Operating Officer of Chesapeake. Mr. McMasters assumed the role of President effective March 1, 2010. He has served as Chief Operating Officer since September of 2008. Prior to these appointments, Mr. McMasters served as 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 of Chesapeake Utilities Corporation since July 2005. She has served as Treasurer of Chesapeake 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 ESNG. 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 ESNG and Regional Manager for the Florida distribution operations.

Joseph Cummiskey was appointed as Vice President of Chesapeake and President of PESCO in December 2009. Mr. Cummiskey joined Chesapeake in December 2005 as the Director of Propane Supply and Wholesale Marketing. In 2008 and 2009, he served as the Director of Strategic Planning/Corporate Development and Director of Propane Operations. Prior to joining Chesapeake, Mr. Cummiskey was employed as a Natural Gas Liquids Regional Director for Ferrell North America. In that position, he was responsible for the purchasing and distribution of Ferrell s propane supply.

Table of Contents

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:

The Company s common stock is listed on the NYSE under the symbol CPK. The high, low and closing prices of the Company s common stock and dividends declared per share for each calendar quarter during the years 2009 and 2008 were as follows:

Quarter Ended	High	Low	Close	Dividends Declared Per Share
2009				
March 31	**$ 32.36**	**$ 22.02**	**$ 30.48**	**$ 0.305**
June 30	**34.55**	**27.62**	**32.53**	**0.315**
September 30	**35.00**	**29.24**	**30.99**	**0.315**
December 31	**32.67**	**29.53**	**32.05**	**0.315**
2008				
March 31	$ 33.60	$ 27.21	$ 29.64	$ 0.295
June 30	31.88	25.02	25.72	0.305
September 30	34.84	24.65	33.21	0.305
December 31	34.66	21.93	31.48	0.305

Holders

At December 31, 2009, there were 2,670 holders of record of Chesapeake common stock.

Dividends

We have paid a cash dividend to common stock shareholders for 49 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. No securities were sold during the year 2009 that were not registered under the Securities Act of 1933, as amended.

Indentures to the long-term debt of the Company 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, 2009, Chesapeake s cumulative consolidated net income base was $102.8 million, offset by Restricted Payments of $63.8 million, leaving $39.0 million of cumulative net income free of restrictions.

Table of Contents

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 2031, which provided 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 2001. As of December 31, 2009, FPU had the cumulative net income base of $32.7 million, offset by restricted payments of $22.1 million, leaving $10.6 million of cumulative net income of FPU free of restrictions based on this covenant. In January 2010, this series of first mortgage bonds were redeemed prior to their maturities. The second most restricted covenant of this type is included in the series that is due in 2022, which provided 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. This covenant provided FPU with the cumulative net income base of $56.0 million, offset by restricted payments of $37.6 million, leaving $18.4 million of cumulative net income of FPU free of restrictions as of December 31, 2009.

(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, 2009.

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, 2009 through October 31, 2009 (1)	587	$ 30.14		
November 1, 2009 through November 30, 2009				
December 1, 2009 through December 31, 2009				
Total	587	$ 30.14		

(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 Note N to the Consolidated Financial Statements. During the quarter, 587 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 compensation plans of Chesapeake and its subsidiaries, 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, 2010, in connection with the Company s Annual Meeting to be held on or about May 5, 2010 and, is incorporated herein by reference.

(c) Chesapeake Utilities Corporation Common Stock Performance Graph

The following stock Performance Graph compares cumulative total shareholder return on a hypothetical investment in our common stock during the five fiscal years ended December 31, 2009, with the cumulative total shareholder 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 11 of the companies in the current Edward Jones Natural Gas Distribution Group, a published listing of selected gas distribution utilities results. The Performance Graph for the previous year included all but one of these same companies. Our Compensation Committee utilizes the Edward Jones Natural Gas Distribution Group as our peer group to which our performance is compared for purposes of determining the level of long-term performance awards earned by our named executives.

The eleven companies in the Edward Jones Natural Gas Distribution Group industry index include: AGL Resources, Inc., Atmos Energy Corporation, Delta Natural Gas Company, Inc., Energy Inc., The Laclede Group, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Co., Inc., RGC Resources, Inc., South Jersey Industries, Inc, and WGL Holdings, Inc.

Table of Contents

The comparison assumes $100 was invested on December 31, 2004 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.

	2004	2005	2006	2007	2008	2009
Chesapeake	$ 100	$ 120	$ 124	$ 133	$ 137	$ 145
Industry Index	$ 100	$ 105	$ 125	$ 129	$ 139	$ 143
S&P 500 Index	$ 100	$ 105	$ 121	$ 128	$ 81	$ 102

Table of Contents

Item 6. Selected Financial Data

For the Years Ended December 31,	2009[3]	2008	2007
Operating [1]			
(in thousands)			
Revenues			
Regulated Energy	**$ 139,099**	$ 116,468	$ 128,850
Unregulated Energy	**119,973**	161,290	115,190
Other	**9,713**	13,685	14,246
Total revenues	**$ 268,785**	$ 291,443	$ 258,286
Operating income			
Regulated Energy	**$ 26,900**	$ 24,733	$ 21,809
Unregulated Energy	**8,158**	3,781	5,174
Other	**(1,322)**	(35)	1,131
Total operating income	**$ 33,736**	$ 28,479	$ 28,114
Net income from continuing operations	**$ 15,897**	$ 13,607	$ 13,218
Assets			
(in thousands)			
Gross property, plant and equipment	**$ 543,746**	$ 381,689	$ 352,838
Net property, plant and equipment [2]	**$ 436,428**	$ 280,671	$ 260,423
Total assets [2]	**$ 617,102**	$ 385,795	$ 381,557
Capital expenditures [1]	**$ 26,294**	$ 30,844	$ 30,142
Capitalization			
(in thousands)			
Stockholders equity	**$ 209,781**	$ 123,073	$ 119,576
Long-term debt, net of current maturities	**98,814**	86,422	63,256
Total capitalization	**$ 308,595**	$ 209,495	$ 182,832
Current portion of long-term debt	**35,299**	6,656	7,656
Short-term debt	**30,023**	33,000	45,664
Total capitalization and short-term financing	**$ 373,917**	$ 249,151	$ 236,152

(1) These amounts exclude the results of distributed energy and water services due to their reclassification

to discontinued operations. The Company closed its distributed energy operation in 2007. All assets of all of the water businesses were sold in 2004 and 2003.

(2) SFAS No. 143 (now codified within FASB ASC 360 and 410) was adopted in the year 2001; therefore, it was not applicable for the years prior to 2001.

(3) 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. These amounts may not be indicative of future results due to the

inclusion of merger effects. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions for addition discussions and presentation of pro forma results.

(4) SFAS No. 123R (now codified within FASB ASC 718, 505 and 260) and SFAS No. 158 (codified within FASB ASC 715) were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

Table of Contents

2006 (4)	2005	2004	2003	2002	2001	2000
$ 124,631	$ 124,563	$ 98,139	$ 92,079	$ 82,098	$ 87,444	$ 82,490
94,320	90,995	67,607	59,197	40,728	56,970	50,428
12,249	13,927	12,209	12,292	12,430	13,992	12,259
$ 231,200	$ 229,485	$ 177,955	$ 163,568	$ 135,256	$ 158,406	$ 145,177
$ 18,593	$ 16,248	$ 16,258	$ 16,219	$ 14,867	$ 14,060	$ 12,672
3,675	4,197	3,197	4,310	1,158	1,259	2,261
1,064	1,476	722	1,050	580	902	1,152
$ 23,332	$ 21,921	$ 20,177	$ 21,579	$ 16,605	$ 16,221	$ 16,085
$ 10,748	$ 10,699	$ 9,686	$ 10,079	$ 7,535	$ 7,341	$ 7,665
$ 325,836	$ 280,345	$ 250,267	$ 234,919	$ 229,128	$ 216,903	$ 192,925
$ 240,825	$ 201,504	$ 177,053	$ 167,872	$ 166,846	$ 161,014	$ 131,466
$ 325,585	$ 295,980	$ 241,938	$ 222,058	$ 223,721	$ 222,229	$ 211,764
$ 49,154	$ 33,423	$ 17,830	$ 11,822	$ 13,836	$ 26,293	$ 22,057
$ 111,152	$ 84,757	$ 77,962	$ 72,939	$ 67,350	$ 67,517	$ 64,669
71,050	58,991	66,190	69,416	73,408	48,409	50,921
$ 182,202	$ 143,748	$ 144,152	$ 142,355	$ 140,758	$ 115,926	$ 115,590
7,656	4,929	2,909	3,665	3,938	2,686	2,665
27,554	35,482	5,002	3,515	10,900	42,100	25,400
$ 217,412	$ 184,159	$ 152,063	$ 149,535	$ 155,596	$ 160,712	$ 143,655

Table of Contents

For the Years Ended December 31,	2009[3]	2008	2007
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [1]	**$ 2.17**	$ 2.00	$ 1.96
Diluted earnings per share from continuing operations [1]	**$ 2.15**	$ 1.98	$ 1.94
Return on average equity from continuing operations [1]	**11.2%**	11.2%	11.5%
Common equity / total capitalization	**68.0%**	58.7%	65.4%
Common equity / total capitalization and short-term financing	**56.1%**	49.4%	50.6%
Book value per share	**$ 22.33**	$ 18.03	$ 17.64
Market price:			
High	**$ 35.000**	$ 34.840	$ 37.250
Low	**$ 22.020**	$ 21.930	$ 28.000
Close	**$ 32.050**	$ 31.480	$ 31.850
Average number of shares outstanding	**7,313,320**	6,811,848	6,743,041
Shares outstanding at year-end	**9,394,314**	6,827,121	6,777,410
Registered common shareholders	**2,670**	1,914	1,920
Cash dividends declared per share	**$ 1.25**	$ 1.21	$ 1.18
Dividend yield (annualized) [2]	**3.9%**	3.9%	3.7%
Payout ratio from continuing operations [1] [4]	**57.6%**	60.5%	60.2%
Additional Data			
Customers [5]			
Natural gas distribution	**117,887**	65,201	62,884
Electric distribution	**31,030**		
Propane distribution	**48,680**	34,981	34,143
Volumes[6]			
Natural gas deliveries (in Mcfs)	**44,586,158**	39,778,067	34,820,050
Electric Distribution (in MWHs)	**105,739**		
Propane distribution (in thousands of gallons)	**32,546**	27,956	29,785
Heating degree-days (Delmarva Peninsula)			
Actual HDD	**4,729**	4,431	4,504
10-year average HDD (normal)	**4,462**	4,401	4,376
Propane bulk storage capacity (in thousands of gallons)	**3,042**	2,471	2,441
Total employees [1] [7]	**757**	448	445

(1) These amounts exclude the results of distributed

energy and water services due to their reclassification to discontinued operations. The Companyclosed its distributed energy operation in 2007. All assets of all of the water businesses were sold in 2004 and 2003.

(2) 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.

(3) 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. These amounts also include the effects of acquisition accounting and issuance of Chesapeake common shares as a result of the

merger. These amounts may not be indicative of future results due to the inclusion of merger effects. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions for addition discussions and presentation of pro forma results.

(4) 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.

(5) Customer data for 2009 includes 51,536, 31,030 and 13,651 of natural gas distribution, electric distribution and propane distribution customers, respectively, from FPU.

(6) Volumes data for 2009 includes 1,109,177 Mcfs, 105,739 MWHs and 1.1 million gallons for natural gas distribution, electric distribution and propane distribution, respectively, delivered by FPU from October 28, 2009 through December 31, 2009.

(7) Total employees for 2009 include 332 FPU employees added to the Company upon the merger, effective October 28, 2009.

Table of Contents

2006 [8]	2005	2004	2003	2002	2001	2000
$ 1.78	$ 1.83	$ 1.68	$ 1.80	$ 1.37	$ 1.37	$ 1.46
$ 1.76	$ 1.81	$ 1.64	$ 1.76	$ 1.37	$ 1.35	$ 1.43
11.0%	13.2%	12.8%	14.4%	11.2%	11.1%	12.2%
61.0%	59.0%	54.1%	51.2%	47.8%	58.2%	55.9%
51.1%	46.0%	51.3%	48.8%	43.3%	42.0%	45.0%
$ 16.62	$ 14.41	$ 13.49	$ 12.89	$ 12.16	$ 12.45	$ 12.21
$ 35.650	$ 35.780	$ 27.550	$ 26.700	$ 21.990	$ 19.900	$ 18.875
$ 27.900	$ 23.600	$ 20.420	$ 18.400	$ 16.500	$ 17.375	$ 16.250
$ 30.650	$ 30.800	$ 26.700	$ 26.050	$ 18.300	$ 19.800	$ 18.625
6,032,462	5,836,463	5,735,405	5,610,592	5,489,424	5,367,433	5,249,439
6,688,084	5,883,099	5,778,976	5,660,594	5,537,710	5,424,962	5,297,443
1,978	2,026	2,026	2,069	2,130	2,171	2,166
$ 1.16	$ 1.14	$ 1.12	$ 1.10	$ 1.10	$ 1.10	$ 1.07
3.8%	3.7%	4.2%	4.2%	6.0%	5.6%	5.8%
65.2%	62.3%	66.7%	61.1%	80.3%	80.3%	73.3%
59,132	54,786	50,878	47,649	45,133	42,741	40,854
33,282	32,117	34,888	34,894	34,566	35,530	35,563
34,321,160	34,980,939	31,429,494	29,374,818	27,934,715	27,263,542	30,829,509
24,243	26,178	24,979	25,147	21,185	23,080	28,469
3,931	4,792	4,553	4,715	4,161	4,368	4,730
4,372	4,436	4,389	4,409	4,393	4,446	4,356
2,315	2,315	2,045	2,195	2,151	1,958	1,928
437	423	426	439	455	458	471

(8) SFAS No. 123R (now codified within FASB ASC 718, 505

and 260) and SFAS No. 158 (codified within FASB ASC 715) were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

Table of Contents

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 and liquidity and capital resources, as well as discussion on 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, 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 above, Risk Factors. They should be considered in connection with evaluating 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. Chesapeake s management uses gross margin in measuring its business units performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

In addition, certain information is presented, which excludes for comparison purposes, result of operations of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009 and all merger-related costs incurred in connection with the FPU merger. Although the non-GAAP measures are not intended to replace the GAAP measures for evaluation of Chesapeake s performance, we believe that the portions of the presentation which excludes FPU s financial results for the post-merger period and merger-related costs provide a helpful comparative basis for investors to understand Chesapeake s performance.

(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 through expansion 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 diversified customer base, energy portfolio and utility foundation.

(b) Highlights and Recent Developments

On October 28, 2009, we completed the previously announced merger with FPU. As a result of the merger, FPU became a wholly-owned subsidiary of Chesapeake. The merger allowed us to become a larger energy company serving approximately 200,000 customers in the Mid-Atlantic and Florida markets, which is twice the number of energy customers we served previously. The merger increased our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing natural gas and propane distribution operations in Florida. It also introduces us to the electric distribution business as it incorporates FPU s approximately 31,000 electric customers in northwest and northeast Florida.

Total consideration paid by Chesapeake in the merger was approximately $75.7 million, which included approximately $16,000 paid in cash and 2,487,910 shares of common stock issued at a price per share of $30.42. Net fair value of the assets acquired and liabilities assumed in the merger was estimated at $42.3 million. This resulted in a purchase premium of $33.4 million, which was reflected as goodwill. All of the purchase premium paid in the merger was related to the regulated energy segment. Chesapeake also incurred approximately $3.0 million in merger-related costs related to consummating the merger, merger-related litigation costs and costs incurred in integrating operations of the two companies. As we intend to seek recovery through future rates of the premium paid and merger-related costs we incurred, we have deferred approximately $1.5 million of the merger-related costs as a regulatory asset as of December 31, 2009.

Our net income for 2009 was $15.9 million, or $2.15 per share (diluted), compared to $13.6 million, or $1.98 per share (diluted), for 2008. These results include approximately $1.5 million in costs expensed in 2009 and $1.2 million in costs related to our initial merger discussions with FPU, which were terminated in 2008. The 2009 results also include approximately $1.8 million in net income contributed by FPU for the period from the merger closing (October 28, 2009) to December 31, 2009. Excluding these merger-related items and net income contributed by FPU, our net income would have been $15.3 million and $14.3 million, or $2.20 per share (diluted) and $2.08 per share (diluted), in 2009 and 2008, respectively.

The following is a summary of key factors affecting our businesses and their impacts on our 2009 results. More detailed discussion and analysis are provided in the Results of Operations section.

Weather. Weather in 2009 was seven percent colder than 2008 and six percent colder than normal on the Delmarva Peninsula. We estimate that colder weather contributed approximately $1.6 million in additional gross margin for our regulated energy and unregulated energy operations on the Delmarva Peninsula in 2009 compared to 2008.

Growth. Customer growth continued to be affected by current economic conditions. Despite the slowdown in growth in the region, our Delaware and Maryland natural gas distribution divisions achieved customer growth in 2009 compared to 2008, which contributed $1.2 million in gross margin for the year. Chesapeake s Florida natural gas distribution division experienced a net customer loss in 2009, which resulted in a gross margin decrease of $190,000. A loss of three large industrial customers in Florida in late 2008 and 2009 contributed primarily to this gross margin decrease. Our natural gas transmission subsidiary, ESNG, experienced continued growth in 2009 through new transmission services and new expansion facilities. New firm services to an industrial customer in 2009 contributed $811,000 to ESNG s gross margin in 2009 and are expected to contribute approximately $1.1 million to its gross margin in 2010. New system expansions in November 2008 and 2009 also contributed $939,000 to its gross margin growth in 2009.

Table of Contents

Propane Prices. A sharp decline in propane prices in late 2008 resulted in inventory and swap valuation adjustments of $1.8 million in 2008, but allowed our Delmarva propane distribution operation to keep its propane cost low during the first half of 2009. The absence of similar inventory valuation adjustments in 2009 and increased margin generated from the low propane cost during the first half of 2009, coupled with sustained retail prices, contributed to increased gross margin of $3.5 million in 2009 compared to 2008 for the Delmarva propane distribution operation. Overall lack of volatility in wholesale propane prices reduced opportunities for our propane wholesale marketing subsidiary, Xeron, and decreased its trading volume by 57 percent in 2009 compared to 2008, which reduced its gross margin by approximately $1.0 million.

Natural Gas Spot Sale Opportunities. Our unregulated natural gas marketing subsidiary, PESCO, was able to identify various spot sale opportunities in 2009, which contributed significantly to the overall gross margin increase of $1.0 million in 2009. During 2009, PESCO sold natural gas and services of $10.6 million to Valero for its Delaware City refinery operation. Late in 2009, Valero announced its intention to permanently shut down that refinery. While PESCO s sale to Valero in 2009 represented approximately 19 percent of PESCO s total revenue for the year, spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts; nor do we anticipate sales to Valero in the future.

Rates and Regulatory Matters. In July 2009, Chesapeake s Florida natural gas distribution division filed with the Florida PSC its petition for a rate increase. In August 2009, the Florida PSC approved an interim rate increase of approximately $418,000. In December 2009, the Florida PSC approved a permanent rate increase of approximately $2.5 million, applicable to all meters read on or after January 14, 2010. In December 2009, FPU s natural gas distribution operation settled its request for a permanent rate increase, which had been approved by the Florida PSC in May 2009; however in June 2009, certain parts of the order approving the increase were protested by the Office of Public Counsel. The settlement allows an annual rate increase of approximately $8.0 million for FPU s natural gas distribution operations.

Information Technology Spending. The state of the economy continued to affect overall information technology spending in 2009. Our advanced information services subsidiary, BravePoint, continued to experience lower consulting revenues as billable consulting hours declined by 28 percent in 2009 compared to 2008. We implemented cost-containment actions, including layoffs and compensation adjustments, which reduced operating costs in 2009 by $1.0 million. BravePoint s professional database monitoring and support solution services, added $218,000 to its gross margin in 2009.

Interest Rates. We continued to experience low short-term interest rates throughout 2009 as our short-term weighted average interest rate decreased to 1.28 percent in 2009, compared to 2.79 percent in 2008. The level of our short-term borrowings in 2009 was reduced by the placement of $30.0 million of 5.93 percent Unsecured Senior Notes in October 2008 and a decline in working capital requirements due to lower commodity prices, lower trading volume by the propane wholesale marketing subsidiary, lower income tax payments from bonus depreciation and the timing of our capital expenditures.

(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.

Table of Contents

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with FASB Accounting Standards Codification (ASC) Topic 980, Regulated Operations, 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 $21.1 million and regulatory liabilities of $46.3 million, at December 31, 2009. If we were required to terminate application of this Topic, 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 O, Environmental Commitments and Contingencies, we have completed our responsibilities related to one environmental site and are currently participating in the investigation, assessment or remediation of seven other former manufactured gas plant sites. Amounts have been recorded as environmental liabilities and associated environmental regulatory assets based on estimates of future costs provided by independent consultants. 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.

Since we believe that recovery of these expenditures, including any litigation costs, is probable through the regulatory process, we have recorded a regulatory asset and corresponding environmental liability. At December 31, 2009, we have recorded an environmental regulatory asset of $7.5 million and a liability of $12.8 million for environmental costs.

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 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, 2009 and 2008:

During 2009 and 2008, our natural gas distribution, electric distribution, propane distribution and natural gas marketing operations entered into physical contracts for 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 the accrual basis of accounting.

During 2008, the propane distribution operation entered into a swap agreement to protect it from the impact of price increases on the Pro-Cap (propane price-cap) Plan that we offer to customers. The propane prices declined significantly in late 2008 and we recorded a mark-to-market adjustment of approximately $939,000, which increased our cost of propane sales in 2008. In January 2009, we terminated this swap agreement. During 2009, we purchased a put option related to the Pro-Cap Plan, which we accounted for on a mark-to-market basis and recorded a loss of $41,000.

Xeron, our propane wholesale marketing subsidiary, enters into forward, futures and other contracts that are considered derivatives. These contracts are marked-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 the years ended December 31, 2009 and 2008, these contracts had net unrealized losses of $1.6 million and net unrealized gains of $1.4 million, respectively.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSCs of the jurisdictions in which we operate. The natural gas transmission operation 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 ESNG to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as a recourse 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 not been accounted for on our delivery systems and must 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 our income statement. 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 costs 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 the Company nor its interruptible customers is 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 experiences, 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.

Table of Contents

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, 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 $892,000, $537,000, and $370,000 in 2009, 2008 and 2007, respectively. The Company expects to record pension and postretirement benefit costs in the range of $900,000 to $1.0 million for 2010 of which $275,000 is attributed to FPU s pension and medical plans. Actuarial assumptions affecting 2010 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 5.25 percent and 5.50 percent for Chesapeake s plan and FPU s plan, respectively. The discount rate for each plan was determined by management considering high quality corporate bond rates based on Moody s Aa bond index, the Citigroup yield curve, changes in those rates from the prior year, and other pertinent factors, such as the expected lives of the plans and the lump-sum-payment option.

Acquisition Accounting

The merger with FPU was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer. The acquisition method of accounting requires, among other things, that the assets acquired and liabilities assumed in the merger be recognized at their fair value as of the acquisition date. It also establishes that the consideration transferred be measured at the closing date of the merger at the then-current market price. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In addition, market participants are assumed to be buyers and sellers in the principal (or the most advantageous) market for the asset or liability and fair value measures for an asset assume the highest and best use by those market participants, rather than our intended use of those assets. Many of these fair value measurements can be highly subjective and it is also possible that others applying reasonable judgment to the same facts and circumstances could develop and support a range of alternative estimated amounts. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature and impact of regulations on those assets and liabilities as a factor in determining their appropriate fair value. We also considered the existence of a regulatory process that would allow, or sometimes require, regulatory assets and liabilities to be established to offset the fair value adjustment to certain assets and liabilities subject to rate regulation. If a regulatory asset or liability should be established to offset the fair value adjustment based on the current regulatory process, as was the case for fuel contracts and long-term debt, we did not gross-up our balance sheet to reflect the fair value adjustment and corresponding regulatory asset/liability, because such gross-up would not have resulted in a change to the value of net assets and future earnings of the Company.

Total consideration paid by Chesapeake in the merger was $75.7 million. Net fair value of the assets acquired and liabilities assumed in the merger was estimated to be $42.3 million. This resulted in a purchase premium of $33.4 million, which was reflected as goodwill. Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions describes more fully the purchase price allocation.

The acquisition method of accounting also requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger for the acquiree. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining proper accounting treatment for the merger-related costs. During 2009, we incurred approximately $3.0 million to consummate the merger, including the cost associated with merger-related litigation, and to integrate operations following the merger. We deferred approximately $1.5 million of the total costs incurred as a regulatory asset at December 31, 2009, which represents our best estimate, based on similar proceedings in Florida in the past, of the costs, which we expect to be permitted to recover when we complete the appropriate rate proceedings. The remaining $1.5 million in costs have been expensed in our 2009 results.

(d) Results of Operations

(in thousands except per share)			**Increase**			**Increase**
For the Years Ended December 31,	**2009**	**2008**	**(decrease)**	**2008**	**2007**	**(decrease)**
Business Segment:						
Regulated Energy	**$ 26,900**	$ 24,733	$ 2,167	$ 24,733	$ 21,809	$ 2,924
Unregulated Energy	**8,158**	3,781	4,377	3,781	5,174	(1,393)
Other	**(1,322)**	(35)	(1,287)	(35)	1,131	(1,166)
Operating Income	**33,736**	28,479	5,257	28,479	28,114	365
Other Income	**165**	103	62	103	291	(188)
Interest Charges	**7,086**	6,158	928	6,158	6,590	(432)
Income Taxes	**10,918**	8,817	2,101	8,817	8,597	220
Net Income from Continuing Operations	**15,897**	13,607	2,290	13,607	13,218	389
Loss from Discontinued Operations					(20)	20
Net Income	**$ 15,897**	$ 13,607	$ 2,290	$ 13,607	$ 13,198	$ 409
Diluted Earnings (Loss) Per Share						
Continuing operations	**$ 2.15**	$ 1.98	$ 0.17	$ 1.98	$ 1.94	$ 0.04
Discontinued operations						
Diluted Earnings Per Share	**$ 2.15**	$ 1.98	$ 0.17	$ 1.98	$ 1.94	$ 0.04

As a result of the merger with FPU in 2009, we changed our operating segments to better align with how the chief operating decision maker (our Chief Executive Officer) views the various operations of the Company. We revised the segment information for all periods presented to reflect the new operating segments. Also during 2009, we decided not to allocate merger-related costs to our operating segments for the purpose of reporting their operating profitability, because such costs are not directly attributable to their operations. Consequently, all of the $1.5 million and $1.2 million of merger-related costs expensed in 2009 and 2008, respectively, are included in Other segment.

2009 compared to 2008

Our net income increased by approximately $2.3 million in 2009 compared to 2008. Net income was $15.9 million, or $2.15 per share (diluted), for 2009, compared to $13.6 million, or $1.98 per share (diluted), for 2008. Our 2009 results include approximately $1.8 million in net income from FPU for the period from the merger closing (October 28, 2009) to December 31, 2009. Our 2009 results also include approximately $1.5 million of merger-related costs expensed by the Company, compared to $1.2 million in merger-related costs expensed in 2008. Absent the effect of the merger and merger-related costs, we estimate that net income would have been $15.3 million, or $2.20 per share (diluted), in 2009, compared to $14.3 million, or $2.08 per share (diluted), in 2008.

During 2009, Chesapeake incurred approximately $3.0 million related to consummating the merger, merger-related litigation costs and costs of integrating operations of the two companies. New accounting standards applicable to acquisitions, which became effective in 2009, require companies to expense merger-related costs in the periods in which they are incurred. Under the previous accounting standards, most of these merger-related costs would have been considered a part of purchase price or liabilities assumed at the merger and thus not expensed. In accounting for our merger-related costs, we also considered the potential impact of the future regulatory process as we intend to seek recovery in future rates of the premium paid and merger-related costs incurred. Similar recovery treatment has been pursued successfully by other regulated utilities. As we account for our regulated operations in accordance with ASC Topic 980, Regulated Operations, certain costs that would otherwise have been expensed by unregulated enterprises may be deferred to reflect the potential impact of the regulatory and rate-making actions. With regard to the $3.0 million in merger-related costs incurred in 2009, we deferred approximately $1.5 million as a regulatory asset, which represents our estimate, based on similar proceedings in Florida in the past, of the costs that we expect to be permitted to recover when we complete the appropriate rate proceedings.

During 2008, we incurred and expensed approximately $1.2 million in merger-related costs. These costs were related to our initial merger discussions with FPU, which were terminated in the second quarter of 2008.

Our operating income increased by $5.3 million in 2009 compared to 2008. Included in operating income for 2009 and 2008 are the $1.5 million and $1.2 million merger-related costs expensed in 2009 and 2008, respectively, which are included in the Other segments. Operating income from our regulated energy segment increased by $2.2 million in 2009. This increase is attributed to $3.0 million of FPU operating income for the period after the merger and an increase in operating income from the natural gas transmission operations through continued growth and new services. Offsetting those increases was a decrease in operating income from Chesapeake s Florida natural gas distribution operation as a result of lower-than-expected customer growth and loss of industrial customers. Operating income for our unregulated energy segment increased by $4.4 million, which includes $553,000 in operating income from FPU after the merger. The Delmarva propane distribution operation contributed most of the increase in operating income by this segment. Delmarva propane distribution operation recorded $1.8 million in unfavorable propane inventory and swap valuation adjustments in 2008, which did not recur in 2009. These adjustments to the inventory costs in late 2008 and relatively low propane prices during the first half of 2009 allowed the Delmarva propane distribution operation to maintain low propane inventory costs while sustaining its retail margins. Operating income for the Other segment decreased by $1.3 million, primarily due to lower operating results by the advanced information services operation and higher merger-related costs expensed in 2009. The operating results of the advanced information services operation continued to be negatively affected by the lower levels of information technology spending experienced in the economy at large.

During 2009, we recognized increased corporate overhead costs of $1.2 million compared to 2008, which were allocated to all of our segments. Payroll and benefits costs in corporate overhead increased by $961,000 and $225,000, respectively, due to higher incentive compensation based on improved operating results and increased costs associated with filling several key corporate positions in 2008 and 2009. Also contributing to the increase were additional costs associated with investor relations and financial reporting activities and increased pension costs as a result of a decline in the value of pension investments in late 2008.

An increase of $928,000 in interest charges in 2009 compared to 2008 partially offset the increased operating results. This increase reflects primarily the interest expense on FPU s long-term debt and customer deposits and the placement of the $30 million Unsecured Senior Notes in October 2008.

We continued to invest in property, plant and equipment in 2009 to support current and future growth opportunities, expending $26.3 million for such purposes.

2008 Compared to 2007

Our net income from continuing operations increased by $389,000 in 2008 compared to 2007. Net income from continuing operations was $13.6 million, or $1.98 per share (diluted), for 2008, compared to $13.2 million, or $1.94 per share (diluted), in 2007. Our 2008 results include a charge of $1.2 million for merger-related costs that were expensed in the second quarter of 2008 when our initial merger discussions with FPU were terminated. Absent the charge for the unconsummated acquisition, the Company estimates that period-over-period net income would have increased by $1.1 million in 2008 to $14.3 million, or $2.08 per share (diluted).

Table of Contents

During 2007, we decided to close the distributed energy services company, Chesapeake OnSight Services, LLC (OnSight), which consistently experienced operating losses since 2004. The results of operations for OnSight were classified to discontinued operations and shown net of tax. The discontinued operations experienced a net loss of $20,000 for 2007.

Our operating income increased by $365,000 in 2008 compared to 2007, including $1.2 million in merger-related costs expensed in 2008, which are included in the Other segment. Operating income from recurring operations increased by $1.5 million in 2008 compared to 2007. Our regulated energy segment achieved an increase of $2.9 million in operating income from new services provided by the natural gas transmission operation, four-percent customer growth for Chesapeake s natural gas distribution operations and the successful completion of the Delaware rate proceedings. Our unregulated energy segment experienced a decrease in operating income of $1.4 million, primarily as a result of recording $1.8 million in unfavorable propane inventory and swap valuation adjustments for the Delmarva propane distribution operations in the second half of 2008. The propane inventory valuation adjustments were recorded to adjust the value of propane inventory and price swap agreements to current market prices as propane prices declined significantly during the second half of 2008. Operating income for the Other segment decreased by $1.2 million due to the merger-related costs.

During 2008, we experienced increased corporate overhead costs, which were allocated to all of our segments. The increase of $519,000 in corporate overhead costs in 2008 compared to 2007 resulted primarily from increased payroll and benefit costs of $132,000 and $83,000, respectively, as several key corporate positions that were vacant in 2007 were filled in 2008 and increased outside services of $263,000 were incurred primarily for consulting costs relating to an independent third-party compensation survey, strategic planning and growth initiatives.

A decrease of $432,000 in interest charges in 2008 compared to 2007 also contributed to the overall increase in net income in 2008. Even though banks were tightening their lending in response to the financial crisis, we were able to firm up our credit lines during this volatile period by increasing our total committed short-term borrowing capacity from $15.0 million to $55.0 million. In addition, on October 31, 2008, we executed a $30.0 million long-term debt placement of 5.93 percent Unsecured Senior Notes.

Table of Contents

We continued to invest in property, plant and equipment in 2008 to support current and future growth opportunities, expending $30.8 million for such purposes.

Regulated Energy

For the Years Ended December 31, *(in thousands)*	2009	2008	Increase (decrease)	2008	2007	Increase (decrease)
Revenue	**$ 139,099**	$ 116,468	$ 22,631	$ 116,468	$ 128,850	$ (12,382)
Cost of sales	**64,803**	54,789	10,014	54,789	70,861	(16,072)
Gross margin	**74,296**	61,679	12,617	61,679	57,989	3,690
Operations & maintenance	**32,569**	25,369	7,200	25,369	25,061	308
Depreciation & amortization	**8,866**	6,694	2,172	6,694	6,918	(224)
Other taxes	**5,961**	4,883	1,078	4,883	4,201	682
Other operating expenses	**47,396**	36,946	10,450	36,946	36,180	766
Operating Income	**$ 26,900**	$ 24,733	$ 2,167	$ 24,733	$ 21,809	$ 2,924

Heating Degree-Day (HDD) and Customer Analysis

For the Years Ended December 31,	2009	2008	Increase (decrease)	2008	2007	Increase (decrease)
Heating degree-day data Delmarva						
Actual HDD	**4,729**	4,431	298	4,431	4,504	(73)
10-year average HDD	**4,462**	4,401	61	4,401	4,376	25
Estimated gross margin per HDD	**$ 2,429**	$ 1,937	$ 492	$ 1,937	$ 1,937	$ 0
Estimated dollars per residential customer added:						
Gross margin	**$ 375**	$ 375	$ 0	$ 375	$ 372	$ 3
Other operating expenses	**$ 100**	$ 103	$ (3)	$ 103	$ 106	$ (3)
Average number of residential customers						
Delmarva	**46,717**	45,570	1,147	45,570	43,485	2,085
Florida	**13,268**	13,373	(105)	13,373	13,250	123
Total	**59,985**	58,943	1,042	58,943	56,735	2,208

2009 Compared to 2008

Operating income for the regulated energy segment increased by approximately $2.2 million, or nine percent, in 2009, compared to 2008, which was generated from a gross margin increase of $12.6 million, offset partially by an operating expense increase of $10.4 million.

Gross Margin

Gross margin for our regulated energy segment increased by $12.6 million, or 20 percent. FPU s natural gas and electric distribution operations had $9.2 million in gross margin for the period from the merger closing (October 28, 2009) to December 31, 2009, which contributed to this increase.

The natural gas distribution operations for the Delmarva Peninsula generated an increase in gross margin of $1.3 million in 2009. The factors contributing to this increase are as follows:

Despite the continued slowdown in the new housing construction and industrial growth in the region, the Delmarva natural gas distribution operations experienced growth in residential, commercial, and industrial customers, which contributed $471,000, $149,000 and $589,000, respectively, to the gross margin increase. A two-percent residential customer growth experienced by the Delmarva natural gas distribution operation in 2009 was lower than the growth experienced in recent years and we expect that trend to continue in the near future.

Colder weather on the Delmarva Peninsula contributed $449,000 to the increased gross margin, as heating degree days increased by 298, or seven percent, compared to 2008.

The Delaware division s new rate structure allows collection of miscellaneous service fees of $256,000, which, although not representing additional revenue, had previously been offset against other operating expenses.

Interruptible sales to industrial customers decreased in 2009 due to a reduction in the price of alternative fuels, which reduced gross margin by $355,000.

Non-weather related customer consumption decreased in 2009, which reduced gross margin by $187,000. The decrease in consumption is a result of conservation primarily by residential customers.

Chesapeake s Florida natural gas distribution operation experienced a decrease in gross margin of $333,000, in 2009. This decrease was attributable to reduced consumption by residential and non-residential customers and loss of three industrial customers, one in 2008 and two in 2009, due to adverse economic conditions in the region. This decrease was partially offset by an increase to gross margin of $99,000 due to implementation of interim rates in the third quarter of 2009.

The natural gas transmission operations achieved gross margin growth of $2.5 million in 2009. The factors contributing to this increase are as follows:

New long-term transmission services implemented by ESNG in November of 2008 and 2009, which provided for an additional 5,459 Mcfs per day and 3,976 Mcfs per day, respectively, added $939,000 to gross margin in 2009.

New firm transmission services provided to an industrial customer for the period of February 6, 2009 through October 31, 2009, provided for an additional 6,957 Mcfs per day and added $574,000 to gross margin. In addition, ESNG entered into two additional firm transmission service agreements with this customer: (1) 6,006 Mcfs per day from November 1, 2009 through November 30, 2009, which added $56,000 to gross margin for 2009; and (2) 9,662 Mcfs per day from November 1, 2009 through October 31, 2012, which added $181,000 to gross margin in 2009 and will contribute $1.1 million in gross margin in 2010.

In April 2009, ESNG changed its rates to recover specific project costs in accordance with the terms of precedent agreements with certain customers. These new rates generated $381,000 in gross margin for 2009 and will contribute $516,000 annually thereafter for a period of 20 years.

During January 2009, PIPECO, our intra-state pipeline subsidiary in Florida, began to provide natural gas transmission service to a customer under a 20 year contract. This agreement contributed $264,000 to gross margin in 2009.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $10.4 million, of which $6.2 million was related to other operating expenses of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009. The remaining increase in other operating expenses is due primarily to the following factors:

Depreciation expense, asset removal costs and property taxes, collectively, increased by approximately $1.4 million as a result of our continued capital investments to support customer growth. Depreciation expense for 2008 also includes a $305,000 depreciation credit as a result of the Delaware negotiated rate settlement agreement in the third quarter of 2008, of which $295,000 related to depreciation for the months of October through December 2007.

Salaries and incentive compensation increased by $803,000, due primarily to compensation adjustments implemented on January 1, 2009 for non-executive employees, based on a compensation survey completed in the fourth quarter of 2008, and annual salary increases, coupled with a slight increase in the accrual for incentive compensation.

The allowance for uncollectible accounts in the natural gas operation increased by $176,000 due to growth in customers and the general economic climate.

Benefit costs increased by $373,000, due primarily to higher pension costs as a result of the decline in the value of pension assets in 2008 and other benefit costs relating to increased payroll costs.

Table of Contents

- Increased information technology spending to continuously enhance our information technology infrastructure and level of support generated increased costs of $285,000.
- Corporate overhead allocated to the regulated energy segment increased by approximately $722,000 due to the factors previously discussed.

Other Developments

The following developments, which are not discussed above, may affect the future operating results of the regulated energy segment:

- ESNG received notice from a customer of its intention not to renew two firm transmission service contracts, one of which expired in October 2009 and the other is expiring in March 2010. If these contracts are not renewed, or equivalent firm service capacity is not contracted to other customers, gross margin could be reduced by approximately $427,000 in 2010. ESNG also received notice from a smaller customer that it does not intend to renew its firm transmission service contract, which expires in April 2010. Revenue from this contract provides annualized gross margin of approximately $54,000.
- In December 2009, the Florida PSC approved a permanent rate increase of approximately $2.5 million for Chesapeake s Florida natural gas distribution division, applicable to all meters read on or after January 14, 2010. Also in December 2009, FPU s natural gas distribution operation settled its request for a permanent rate increase, which was approved by the Florida PSC in May 2009; however, in June 2009, certain parts of the order were protested by the Office of Public Counsel. The settlement provides for an annual rate increase of approximately $8.0 million. As a result of the settlement, FPU refunded approximately $290,000 to its customers in February 2010, which represents revenues in excess of the amounts provided by the settlement agreement that had been billed to customers from June 4, 2009 to January 13, 2010.
- The Delaware division is currently involved in a regulatory proceeding regarding the price it charged for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, PESCO. The Hearing Examiner recommended, among others, a refund to our Delaware firm customers, which could be up to approximately $700,000, exclusive of any interest, as of December 31, 2009. We disagree with the Hearing Examiner s recommendations and filed exceptions to those recommendations. We have not recorded a liability for this contingency based on our current assessment of the case. We anticipate a ruling by the Delaware PSC in March 2010. Item 8 under the heading, Notes to the Consolidated Financial Statements Note P, Other Commitments and Contingencies provides further discussions on this matter.

2008 Compared to 2007

Operating income for the regulated energy segment increased by approximately $2.9 million in 2008 compared to 2007, which was attributable to a gross margin increase of $3.7 million, offset partially by an operating expense increase of $766,000.

Gross Margin

Gross margin for our regulated segment increased by $3.7 million, or six percent, of which $2.0 million was attributable to the natural gas distribution operations and $1.7 million to the natural gas transmission operation.

The Delmarva natural gas distribution operations generated an increase to gross margin of $1.8 million due to the following factors:

- The average number of residential customers on the Delmarva Peninsula increased by 2,085, or five percent, for 2008, and we estimate that these additional residential customers contributed approximately $850,000 to gross margin in 2008.
- Growth in commercial and industrial customers contributed $473,000 and $89,000, respectively, to gross margin in 2008.
- Interruptible services revenue, net of required margin-sharing, increased by $307,000 as customers took advantage of lower natural gas prices compared to prices for alternative fuels.

- We estimate that weather contributed $122,000 to gross margin, despite temperatures on the Delmarva Peninsula being two percent warmer in 2008, compared to 2007.
- Partially offsetting these increases to gross margin was the negative impact of lower consumption per customer in 2008 compared to 2007. We estimate that lower consumption per customer reduced gross margin by $118,000. The lower consumption reflects customer conservation efforts in light of higher energy costs, more energy-efficient housing, and current economic conditions.

Gross margin for the Florida natural gas distribution operation increased by $200,000 in 2008, compared to 2007. The higher gross margin for the period was attributable primarily to a one-percent growth in residential customers, an increase in non-residential customer volumes, and higher revenues from third-party natural gas marketers.

The natural gas transmission operation achieved gross margin growth of $1.7 million in 2008, $1.2 million of which was attributable to new transmission capacity contracts implemented in November 2007 and 2008. In addition, the implementation of rate case settlement rates, effective September 1, 2007, contributed an additional $439,000 to gross margin in 2008. The remaining $61,000 increase to gross margin was attributable primarily to higher interruptible sales revenue, net of required margin-sharing.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by approximately $766,000, due primarily to the following factors:

- Payroll and benefit costs increased by $486,000 and $152,000, respectively, reflecting annual compensation increases and increased staff to support compliance with new federal pipeline integrity regulations and to serve the additional growth.
- Depreciation expense and asset removal costs decreased by approximately $1.5 million, primarily as a result of our Delaware distribution operation s rate proceedings in 2008 and ESNG s rate settlement in September 2007, which provided for lower depreciation and asset removal cost allowances. Higher depreciation expense from the increased level of capital investment partially offset this decrease in 2008.
- Property taxes increased by approximately $609,000 due to the higher level of capital investment and adjusted property assessments by various jurisdictions.
- Vehicle-related costs increased by $132,000 due to higher fuel and depreciation charges.
- Information technology costs increased by approximately $517,000 as a result of higher spending to improve the infrastructure, including system performance, disaster recovery and support.
- Corporate overhead costs allocated to the regulated energy segment increased by approximately $385,000 as previously discussed.

Table of Contents

Unregulated Energy

For the Years Ended December 31,	2009	2008	Increase (decrease)	2008	2007	Increase (decrease)
(in thousands)						
Revenue	**$ 119,973**	$ 161,290	$ (41,317)	$ 161,290	$ 115,190	$ 46,100
Cost of sales	**90,408**	138,302	(47,894)	138,302	91,727	46,575
Gross margin	**29,565**	22,988	6,577	22,988	23,463	(475)
Operations & maintenance	**18,016**	16,322	1,694	16,322	15,559	763
Depreciation & amortization	**2,415**	2,024	391	2,024	1,842	182
Other taxes	**976**	861	115	861	888	(27)
Other operating expenses	**21,407**	19,207	2,200	19,207	18,289	918
Operating Income	**$ 8,158**	$ 3,781	$ 4,377	$ 3,781	$ 5,174	$ (1,393)

Propane Heating Degree-Day (HDD) Analysis Delmarva

For the Years Ended December 31,	2009	2008	Increase (decrease)	2008	2007	Increase (decrease)
Heating degree-days						
Actual	**4,729**	4,431	298	4,431	4,504	(73)
10-year average	**4,462**	4,401	61	4,401	4,376	25
Estimated gross margin per HDD	**$ 3,083**	$ 2,465	$ 618	$ 2,465	$ 1,974	$ 491

<u>2009 compared to 2008</u>

Operating income for the unregulated energy segment increased by approximately $4.4 million in 2009 compared to 2008, which was attributable to a gross margin increase of $6.6 million, offset partially by an operating expense increase of $2.2 million.

<u>Gross Margin</u>

Gross margin for our unregulated energy segment increased by $6.6 million, or 29 percent, in 2009 compared to 2008. FPU s propane distribution operation contributed $1.8 million to gross margin during the period from the merger closing (October 28, 2009) to December 31, 2009.

PESCO, our natural gas marketing operation, experienced an increase in gross margin of $1.0 million in 2009. PESCO increased its sales volume by 13 percent in 2009 compared to 2008, as it benefited from increased spot sale opportunities on the Delmarva Peninsula during 2009, which contributed significantly to the gross margin increase. Spot sales are opportunistic and unpredictable, and their future availability is highly dependent upon market conditions.

The propane distribution operation, excluding FPU, increased its gross margin by $4.8 million. The absence of inventory valuation adjustments in 2009 and lower propane costs, coupled with sustained retail prices, contributed $3.5 million of the gross margin increase. A sharp decline in propane prices in late 2008 resulted in a loss associated with the inventory and swap valuation adjustments of $1.8 million in 2008. These inventory adjustments in 2008 and relatively low propane prices during the first half of 2009 allowed the Delmarva propane distribution operation to keep its propane cost low. Colder weather on the Delmarva Peninsula in 2009 increased gross margin by $1.2 million, as temperatures were seven percent colder in 2009, compared to 2008. Gross margin for the Florida propane distribution operation in 2009 remained unchanged from 2008 as increased margins per retail gallon were offset by a decline in residential and non-residential consumption.

The propane wholesale marketing operation experienced a reduction in gross margin of $1.0 million in 2009. The propane wholesale marketing operation typically capitalizes on price volatility by selling at prices above cost and effectively managing the larger spreads between the market (spot) prices and forward prices. Overall lack of volatility in wholesale propane prices in 2009, compared to 2008, reduced such revenue opportunities and its trading volume by 57 percent.

Table of Contents

Other Operating Expenses

Total other operating expenses for the unregulated energy segment increased by $2.2 million in 2009, of which $1.2 million was related to other operating expenses of FPU during the period from the merger closing (October 28, 2009) to December 31, 2009. The remaining increase in other operating expenses is due primarily to the following factors:

- Payroll costs increased by $301,000 in 2009 compared to 2008 due to annual salary increases.
- Benefit costs increased by $167,000, due primarily to increased pension costs in 2009 as a result of the decline in the value of pension plan assets.
- Depreciation expense increased by $249,000 as we continued to make capital investments in the propane distribution operations.
- Additional costs of approximately $115,000 were incurred in 2009 to maintain propane tanks in compliance with United States Department of Transportation standards.
- Corporate overhead allocated to the unregulated energy segment increased by approximately $568,000 as previously discussed.
- These increases were partially offset by lower vehicle-related costs of $176,000, primarily due to a decrease in the cost of fuel.

Other Developments

The following developments, which are not discussed above, may affect the future operating results of the unregulated energy segment:

- On November 20, 2009, Valero announced that it was permanently shutting down its refinery operation located in Delaware City, Delaware. During 2009, PESCO sold natural gas and services for $10.6 million to Valero. PESCO s natural gas sales to Valero were on a spot sale basis. PESCO s sale to Valero represented 19 percent of its total sales in 2009. Spot sales are not predictable, and therefore, are not included in our long-term financial plans or forecasts; nor do we anticipate sales to Valero in the future.
- In February 2010, Sharp, our Delmarva propane distribution subsidiary, purchased the operating assets of a regional propane distributor serving approximately 1,000 retail customers in Northampton and Accomack, Virginia.

2008 Compared to 2007

Operating income for the unregulated energy segment decreased by approximately $1.4 million, or 27 percent, in 2008 compared to 2007, which was attributable to a gross margin decline of $475,000 and an operating expense increase of $918,000.

Gross Margin

The period-over-period decrease in gross margin of $475,000, or two percent, for the unregulated energy segment was due to $2.9 million in decreased gross margin for the propane distribution operations, which was offset by the increase to gross margin of $901,000 for the propane wholesale marketing operation and $1.5 million for the natural gas marketing operation.

The Delmarva propane distribution operation s decrease in gross margin of $3.1 million resulted from the following:

- Gross margin decreased by $1.1 million in 2008, compared to 2007, primarily because of a $0.04 decrease in the average gross margin per retail gallon attributable to inventory write-downs of approximately $800,000 during 2008 in response to market prices below the Company s inventory price per gallon.

- Wholesale propane prices rose dramatically during the spring of 2008, when they traditionally fall. In efforts to protect the Company from the impact that additional price increases would have on our Pro-Cap (propane price cap) Plan, the propane distribution operation entered into a swap agreement. By the end of the period, the market price of propane had plummeted well below the unit price in the swap agreement. As a result, we marked the agreement relating to the January 2009 and February 2009 gallons to market, which increased cost of sales by $939,000 in 2008. In January 2009, we terminated this swap agreement.
- Non-weather-related volumes sold in 2008 decreased by 1.2 million gallons, or five percent. This decrease in gallons sold reduced gross margin by approximately $867,000 for the Delmarva propane distribution operation. Factors contributing to this decrease in gallons sold included customer conservation and the timing of propane deliveries.
- Margins per gallon on the Pro-Cap Plan for the last four months of 2008 recovered to a level just $113,000 below the prior year s levels, despite realizing a charge to cost of sales of $494,000 as the December gallons related to this plan were valued at current market prices.
- Temperatures on the Delmarva Peninsula were two percent warmer in 2008 compared to 2007, which contributed to a decrease of 248,000 gallons sold, or one percent. We estimated that the warmer weather and decreased volumes sold had a negative impact of approximately $180,000 on gross margin for the Delmarva propane distribution operation.
- Gross margin from miscellaneous fees, including items such as tank and meter rentals and marketing pricing programs, increased by $271,000.

The Florida propane distribution operation experienced an increase in gross margin of $181,000 in 2008, compared to 2007. The higher gross margin resulted from increases of four percent and 10 percent in the number of gallons sold to residential and commercial customers, respectively, combined with a higher average gross margin per retail gallon.

Gross margin for the propane wholesale marketing operation increased by $901,000 in 2008, compared to 2007. This increase reflects the operation capitalizing on a larger number of market opportunities that arose in 2008 due to price volatility in the propane wholesale market. This volatility created an opportunity for the operation to capture larger price-spreads between sales contracts and purchase contracts in addition to larger spreads between the market (spot) prices and forward propane prices.

Gross margin for the natural gas marketing operation increased by $1.5 million for 2008, compared to 2007. The increase in gross margin was due to enhanced sales contract terms, margins on spot sales of approximately $600,000 and 26-percent growth in its customer base. The increased customer base contributed to a 41-percent increase in volumes sold in 2008.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $918,000 due primarily to the following factors:

- Payroll and benefit costs decreased by $186,000, due primarily to lower accrual for incentive compensation as a result of lower operating results in 2008.
- Vehicle-related costs increased by $207,000 as a result of higher fuel costs and continued maintenance of our delivery trucks.
- Depreciation and amortization expense increased by $182,000 as a result of an increase in our capital investments, primarily in Community Gas Systems.
- The allowance for uncollectible accounts increased by $436,000 due to increased revenue.
- Maintenance expense decreased by $193,000, due primarily to additional costs in 2007 associated with propane tank recertifications and maintenance to comply with the Department of Transportation standards.
- Information technology costs increased by approximately $153,000 as a result of higher spending to improve the infrastructure, including system performance, disaster recovery and support.
- Corporate overhead costs increased by approximately $204,000 as previously discussed.

Table of Contents

Other

For the Years Ended December 31, *(in thousands)*	2009	2008	Increase (decrease)	2008	2007	Increase (decrease)
Revenue	**$ 11,998**	$ 15,373	$ (3,375)	$ 15,373	$ 15,721	$ (348)
Cost of sales	**6,036**	8,034	(1,998)	8,034	8,260	(226)
Gross margin	**5,962**	7,339	(1,377)	7,339	7,461	(122)
Operations & maintenance	**4,859**	5,206	(347)	5,206	5,333	(127)
Transaction-related costs	**1,478**	1,153	325	1,153		1,153
Depreciation & amortization	**310**	290	20	290	304	(14)
Other taxes	**640**	728	(88)	728	697	31
Other operating expenses	**7,287**	7,377	(90)	7,377	6,334	1,043
Operating Income Other	**(1,325)**	(38)	(1,287)	(38)	1,127	(1,165)
Operating Income Eliminations	**3**	3		3	4	(1)
Operating Income	**$ (1,322)**	$ (35)	$ (1,287)	$ (35)	$ 1,131	$ (1,166)

2009 compared to 2008

Operating loss for the Other segment increased by approximately $1.3 million in 2009 compared to 2008. The increased loss was attributable primarily to the gross margin decrease of $1.4 million in the advanced information services operation.

Gross margin

The period-over-period decrease in gross margin for the Other segment was a result of a decrease in consulting revenues by the advanced information services operation due primarily to a 28-percent decrease in the number of billable consulting hours, coupled with a decline in training revenues. The reduction in the number of billable consulting hours is a result of current economic conditions in which information technology spending has not rebounded. The decrease in consulting revenues was partially offset with an increase of $218,000 from BravePoint s professional database monitoring and support solution services, and increased product sales of $140,000. While there have been some improvement in recent months, we do not expect customers information technology spending to return to historical levels in the foreseeable future given the current economic climate.

Operating expenses

Other operating expenses decreased by $90,000 in 2009. The decrease in operating expenses was attributable primarily to the cost containment actions, including layoffs and compensation adjustments, implemented by the advanced information service operation in 2009 to reduce costs to offset the decline in revenues. This decrease was offset by the increased merger-related costs.

2008 Compared to 2007

Operating income for the Other segment decreased by approximately $1.2 million in 2008 compared to 2007, which was attributable to a gross margin decrease of $122,000 and an operating expense increase of $1.0 million.

Gross margin

Our advanced information services operation contributed most of the gross margin for the Other segment. Gross margin for our advanced services operation declined by approximately $152,000, which was attributable to a decrease of $610,000 in consulting revenues as higher average billing rates were not able to overcome a nine-percent decrease in the number of billable consulting hours. The reduction in the number of billable hours was a result of economic conditions in which information technology spending broadly declined. The decrease in consulting revenues was partially offset with increased product sales and training revenues of $403,000 and $47,000, respectively.

Table of Contents

The increase in other operating expenses in 2008 was primarily related to $1.2 million in merger-related costs in 2008 that were expensed in the second quarter of 2008 when initial discussions with FPU regarding a potential merger were terminated. Other operating expenses for our advanced information services operation remained relatively unchanged in 2008 compared to 2007.

Other Income

Other income for 2009, 2008 and 2007 was $163,000, $103,000 and $291,000, respectively, which includes interest income, late fees charged to customers and gains or losses from the sale of assets.

Interest Expense

2009 Compared to 2008

Total interest expense for 2009 increased by approximately $928,000, or 15 percent, compared to 2008. Total interest expense for 2009 includes approximately $741,000 in FPU s interest expense for the period from the merger closing (October 28, 2009) to December 31, 2009, which is primarily related to $610,000 in interest on FPU s long-term debt and $115,000 in interest on customer deposits. FPU s weighted average interest rate was 7.41 percent for the period from the merger closing to December 31, 2009.

The remaining increase in interest expense in 2009 was attributable to the following factors:

- Excluding FPU s long-term debt, interest expense on long-term debt increased by $990,000 as our average long-term debt balance increased to $92.1 million in 2009 from $76.2 million in 2008. This increase was primarily related to the placement of $30.0 million of 5.93 percent Unsecured Senior Notes in October 2008. The weighted average interest rate on our long-term debt remained unchanged at 6.37 percent in 2009, compared to 6.40 percent in 2008.
- Interest expense in short-term borrowing decreased by $852,000 in 2009, compared to 2008, as our average short-term borrowing balance decreased to $13.0 million in 2009 from $38.3 million in 2008. The $30.0 million long-term placement in October 2008 contributed to this decrease as well as a decrease in working capital requirements in 2009, compared to 2008, due to lower capital expenditures, lower income tax payments from bonus depreciation, net tax operating losses carried forward from 2008 and lower commodity costs. The impact from these factors was offset slightly by the increased working capital needs as a result of the FPU merger. Also contributing to the decrease in interest expense in short-term borrowing was a decrease in the weighted average short-term interest rate to 1.28 percent in 2009 from 2.79 percent in 2008 as we continued to experience low interest rates throughout 2009.
- Other interest charges increased by $49,000.

In January 2010, we redeemed $28.7 million of the secured first mortgage bonds with a carrying value of $27.2 million to increase financial flexibility by reducing the amount of the FPU secured long-term debt and maintaining compliance with the covenants in our unsecured senior notes.

2008 Compared to 2007

Total interest expense for 2008 decreased by approximately $432,000, or seven percent, compared to 2007. The lower interest expense is primarily the result of the following:

- Interest on long-term debt decreased by $263,000 in 2008, compared to 2007, as we reduced our average long-term debt balance and weighted average interest rate. Our average long-term debt balance during 2008 was $76.2 million, with a weighted average interest rate of 6.40 percent, compared to $76.5 million, with a weighted average interest rate of 6.71 percent, for the same period in 2007.

Other interest charges decreased by $127,000 as higher amounts of interest capitalized were partially offset by interest accrued on pending customer refunds.

Interest on short-term borrowings decreased by $42,000 in 2008 compared to 2007, as the weighted average interest rate was nearly 2.7 percentage points lower in 2008 offsetting a $17.7 million increase in our average short-term borrowing balance. Our average short-term borrowing during 2008 was $38.3 million, with a weighted average interest rate of 2.79 percent, compared to $20.6 million, with a weighted average interest rate of 5.46 percent, for 2007.

Income Taxes

2009 Compared to 2008

Income tax expense was $10.9 million in 2009, compared to $8.8 million in 2008, representing an increase of $2.1 million. During 2009, we expensed approximately $871,000 in merger-related costs that were determined to be non-deductible for income tax purposes. Excluding the impact of these costs, our effective income tax rate for 2009 and 2008 remained primarily unchanged at 39.4 percent and 39.3 percent, respectively. The increase in income tax expense reflects the increased taxable income in 2009.

2008 Compared to 2007

Income tax expense was $8.8 million in 2008, compared to $8.6 million in 2007, representing an increase of $200,000. Our effective income tax rate for 2008 and 2007 remained primarily unchanged at 39.3 percent and 39.4 percent, respectively. The increase in income tax expense reflects the increased taxable income in 2008.

Discontinued Operations

During 2007, we decided to close the distributed energy services subsidiary, OnSight, which had experienced operating losses since its inception in 2004. The results of operations for OnSight have been reclassified to discontinued operations and shown net of tax for all periods presented. The discontinued operations experienced a net loss of $20,000 for 2007. We did not have any discontinued operations in 2008 and 2009.

(e) Liquidity and Capital Resources

Our capital requirements reflect the capital-intensive nature of our business and are principally attributable to investment in new plant and equipment and retirement of outstanding debt. We rely on cash generated from operations, short-term borrowing, and other sources to meet normal working capital requirements and to finance capital expenditures.

During 2009, net cash provided by operating activities was $45.8 million, cash used in investing activities was $23.1 million, and cash used in financing activities was $21.4 million. Cash provided during 2009 includes approximately $359,000 of net cash acquired in the merger with FPU.

During 2008, net cash provided by operating activities was $28.5 million, cash used by investing activities was $31.2 million, and cash provided by financing activities was $1.7 million.

During 2007, net cash provided by operating activities was $25.7 million, cash used by investing activities was $31.3 million, and cash provided by financing activities was $3.7 million.

As of December 31, 2009, we had four unsecured bank lines of credit with two financial institutions, for a total of $90.0 million, none of which requires compensating balances. In January 2010, the total unsecured bank lines of credit increased to $100.0 million, none of which requires compensating balances. These bank lines are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to fund temporarily portions of the capital expenditure program. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these short-term lines of credit. In response to the instability and volatility of the financial markets during 2008, we solidified our lines of credit by converting $40.0 million of available credit under uncommitted lines to committed lines of credit. Currently, two of the bank lines, totaling $60.0 million, are committed. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. The outstanding balance of short-term borrowing at December 31, 2009 and 2008 was $30.0 million and $33.0 million, respectively. The level of short-term debt was reduced in late 2008 and throughout 2009 with funds provided from the placement of $30 million of 5.93 percent Unsecured Senior Notes in October 2008. This reduction was offset in late 2009 by the increased working capital requirements after the FPU merger.

We have budgeted $53.9 million for capital expenditures during 2010. This amount includes $49.2 million for the regulated energy segment, $3.3 million for the unregulated energy segment and $1.4 million for the Other segment. The amount for the regulated energy segment includes estimated capital expenditures for the following: natural gas distribution operation ($20.2 million), natural gas transmission operation ($25.4 million) and electric distribution operation ($3.6 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 an estimated capital expenditure of $288,000 for the advanced information services operation with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2010 capital expenditures program from short-term borrowing, cash provided by operating activities, and other sources. The capital expenditure 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.

Capital Structure

In consummating the FPU merger, Chesapeake issued 2,487,910 shares of its common stock, valued at approximately $75.7 million, in exchange for all outstanding common stock of FPU. We also became subject to FPU s long-term debt of $47.8 million as a result of the merger. The following presents our capitalization as of December 31, 2009 and 2008:

(in thousands)	**December 31, 2009**		**December 31, 2008**	
Long-term debt, net of current maturities	**$ 98,814**	**32%**	$ 86,422	41%
Stockholders equity	**209,781**	**68%**	123,073	59%
Total capitalization, excluding short-term debt	**$ 308,595**	**100%**	$ 209,495	100%

As of December 31, 2009, common equity represented 68 percent of total capitalization, compared to 59 percent at December 31, 2008. As of December 31, 2009, we classified as a current portion of long-term debt two series of FPU s secured first mortgage bonds in the amount of approximately $27.2 million because we redeemed them in January 2010 prior to their stated maturities in order to maintain increased financial flexibility and compliance with the covenants in our Unsecured Senior Notes. We used the short-term borrowing to finance the redemption of these bonds.

Table of Contents

The following presents our capitalization as of December 31, 2009 and 2008, if short-term borrowing and the current portion of long-term debt were included in capitalization:

(in thousands)	December 31, 2009		December 31, 2008	
Short-term debt	**$ 30,023**	**8%**	$ 33,000	13%
Long-term debt, including current maturities	**134,113**	**36%**	93,078	38%
Stockholders equity	**209,781**	**56%**	123,073	49%
Total capitalization, including short-term debt	**$ 373,917**	**100%**	$ 249,151	100%

Excluding $75.7 million of the value of Chesapeake s common stock issued in the merger and $47.8 million of FPU s long-term debt included in our Consolidated Balance Sheet at December 31, 2009, total capitalization increased by $1.3 million in 2009.

We remain 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.

Cash Flows Provided by Operating Activities

Our cash flows provided by operating activities were as follows:

For the Years Ended December 31, *(in thousands)*	**2009**	**2008**	**2007**
Net income	**$ 15,897**	$ 13,607	$ 13,198
Non-cash adjustments to net income	**28,319**	22,919	15,829
Changes in assets and liabilities	**1,593**	(7,982)	(3,346)
Net cash from operating activities	**$ 45,809**	$ 28,544	$ 25,681

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

We 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.

Table of Contents

In 2009, our net cash flow provided by operating activities was $45.8 million, an increase of $17.3 million compared to 2008. This increase includes $4.7 million in net cash flow provided by the operating activities of FPU after the merger. The remaining increase was due primarily to the following:

- Net cash flows from the change in income taxes receivable and non-cash adjustments for deferred income taxes were related to continued higher tax deductions provided by bonus depreciation, which resulted in net federal income tax refunds received in 2009 and continued to create higher book-to-tax timing differences;
- Net cash flows from changes in accounts receivable and accounts payable were due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale marketing operation; and
- Net cash flows from the increase in regulatory liabilities were due primarily to higher over-collection of purchased gas costs by our Delmarva natural gas distribution operation.

In 2008, our net cash flow provided by operating activities was $28.5 million, an increase of $2.9 million compared to 2007. The increase was due primarily to the following:

- Net cash flows from changes in accounts receivable and accounts payable were due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale and marketing operation;
- Timing of payments for the purchase of propane inventory, natural gas purchases injected into storage, and the relative decline in the unit price of these commodities;
- Reduction in regulatory liabilities, which resulted primarily from lower deferred gas cost recoveries in our natural gas distribution operations as the price of natural gas declined in the second half of 2008;
- Reduced payments for income taxes payable as a result of higher tax deductions provided by the 2008 Economic Stimulus Act; and
- Cash flows provided by non-cash adjustments for deferred income taxes. The increase in deferred income taxes is the result of higher book-to-tax timing differences during the period that were generated by the Economic Stimulus Act, which authorized bonus depreciation for certain assets.

Cash Flows Used in Investing Activities

In 2009, net cash flows used by investing activities totaled $23.1 million, a decrease of $8.1 million compared to 2008. In 2008, net cash flows used by investing activities totaled $31.2 million, which remained relatively unchanged from net cash flows used by investing activities of $31.3 million in 2007.

- We acquired $359,000 in cash, net of cash paid, in the merger with FPU in 2009.
- We received $3.5 million in proceeds from an investment account related to future environmental costs, which was previously included as a non-current investment, as we transferred the amount to our general account that invests in overnight income-producing securities. Our general account is considered cash equivalent.
- Cash utilized for capital expenditures was $26.6 million, $30.8 million and $31.3 million for 2009, 2008, and 2007, respectively.
- Environmental expenditures exceeded amounts recovered through rates charged to customers in 2009, 2008 and 2007 by $418,000, $480,000 and $228,000, respectively.
- Sales of property, plant, and equipment generated $205,000 of cash in 2007.

Table of Contents

Cash Flows Provided by Financing Activities

In 2009, net cash flows used by financing activities totaled $21.4 million, compared to net cash flow provided by financing activities of $1.7 million and $3.7 million in 2008 and 2007, respectively. Significant financing activities included the following:

- During 2009 and 2008, we reduced our short-term debt by $3.8 million and $12.0 million, respectively. During 2007, net borrowing of short-term debt increased by $18.7 million, primarily to support our capital investments.
- In October 2008, we completed the placement of $30.0 million of 5.93 percent Unsecured Senior Notes.
- We repaid $10.9 million of long-term debt during 2009, compared to $7.7 million of long-term debt repaid during each of 2008 and 2007.
- We paid $8.0 million, $7.8 million and $7.0 million in cash dividends in 2009, 2008 and 2007, respectively. An increase in cash dividends paid in each year reflects the growth in the annualized dividend rate.

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2009:

	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]	$ 36,765	$ 17,293	$ 20,793	$ 60,818	$ 135,669
Operating leases [2]	866	1,449	865	2,031	5,211
Purchase obligations [3]					
Transmission capacity	11,133	38,589	20,447	63,028	133,197
Storage Natural Gas	530	6,600	2,001	968	10,099
Commodities	54,802	341			55,143
Electric supply	574	1,149	1,149	2,298	5,170
Forward purchase contracts					
Propane [4]	12,570				12,570
Other	1,557	16			1,573
Unfunded benefits [5]	371	1,504	847	4,926	7,648
Funded benefits [6]	2,090	79	670	1,170	4,009
Total Contractual Obligations	**$ 121,258**	**$ 67,020**	**$ 46,772**	**$ 135,239**	**$ 370,289**

(1) Principal payments on long-term debt, see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-Term

Debt , for additional discussion of this item. The expected interest payments on long-term debt are $7.5 million, $12.6 million, $10.1 million and $17.3 million, respectively, for the periods indicated above. Expected interest payments for all periods total $47.6 million.

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

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

(4) We have also entered into forward sale

contracts. See Market Risk of the Management s Discussion and Analysis for further information.

(5) We have recorded long-term liabilities of $7.6 million at December 31, 2009 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assumes a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations.

(6) We have recorded long-term liabilities of $12.7 million at December 31, 2009 for two qualified, defined benefit pension

plans. The assets funding these plans are in a separate trust and are not considered assets of the Company or included in the Company s balance sheets. The Contractual Obligations table above includes $2.0 million, reflecting the expected payments the Company will make to the trust funds in 2010. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See Item 8 under the heading Notes to the Consolidated Financial Statements Note M, Employee Benefit Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling $2.0 million funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the Balance Sheet. We assume a retirement age of 65 for purposes of distribution from this account.

Table of Contents

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and the natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. None of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2009 was $22.7 million, with the guarantees expiring on various dates in 2010.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $725,000, which expires on August 31, 2010. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of December 31, 2009.

(f) Rate Filings and Other Regulatory Activities

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by their respective PSC; ESNG is subject to regulation by the FERC; and PIPECO is subject to regulation by the Florida PSC. At December 31, 2009, Chesapeake was involved in rate filings and/or regulatory matters in each of the jurisdictions in which it operates. Each of these rate filings or regulatory matters is fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note P, Other Commitments and Contingencies.

(g) Environmental Matters

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

(h) Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures (see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-term Debt for annual maturities of consolidated long-term debt). All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was $134.1 million at December 31, 2009, as compared to a fair value of $145.5 million, based on a discounted cash flow methodology that incorporates a market interest rate that is based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

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

Table of Contents

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third-parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of natural gas liquids to us or the counter-party or booking out the transaction. Booking out is a procedure for financially settling a contract in lieu of the physical delivery of energy. The propane wholesale marketing operation also enters into futures contracts that are traded on the New York Mercantile Exchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The propane wholesale marketing business is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets and the credit risk of counter-parties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and futures contracts at December 31, 2009 and 2008 is presented in the following tables.

At December 31, 2009	Quantity in gallons	Estimated Market Prices		Weighted Average Contract Prices	
Forward Contracts					
Sale	11,944,800	$0.6900	$1.3350	$	1.1264
Purchase	11,256,000	$0.7275	$1.3350	$	1.1367
Other Contract					
Put option	1,260,000	$		$	0.1500

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire in the first quarter of 2010.

At December 31, 2008	Quantity in gallons	Estimated Market Prices		Weighted Average Contract Prices	
Forward Contracts					
Sale	10,626,000	$0.5450	$1.9100	$	0.9984
Purchase	9,949,800	$0.7000	$1.9600	$	1.0233

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expired in 2009.

At December 31, 2009 and 2008, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	December 31, 2009		December 31, 2008	
Mark-to-market energy assets	**$**	**2,379**	$	4,482
Mark-to-market energy liabilities	**$**	**2,514**	$	3,052

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

(i) Competition

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

Our electric distribution operation currently does not face substantial competition as the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

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

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

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

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

Table of Contents

(j) Inflation

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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

Item 8. Financial Statements and Supplementary Data.

Management s Report on Internal Control Over Financial Reporting

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

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

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. Chesapeake is in the process of integrating FPU s operations and has not included FPU s activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions for additional information relating to the FPU merger. FPU s operations constituted approximately 30 percent of total assets (excluding goodwill and other intangible assets) as of December 31, 2009, and 10 percent of operating revenues for the year then ended. FPU s operations will be included in Chesapeake s assessment as of December 31, 2010.

Chesapeake s management has evaluated and concluded that Chesapeake s internal control over financial reporting was effective as of December 31, 2009.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2009. Chesapeake Utilities Corporation s management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Chesapeake Utilities Corporation as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Chesapeake Utilities Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 8, 2010 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2010

Table of Contents

Consolidated Statements of Income

For the Years Ended December 31, *(in thousands, except shares and per share data)*	2009	2008	2007
Operating Revenues			
Regulated Energy	**$ 139,099**	$ 116,468	$ 128,850
Unregulated Energy	**119,973**	161,290	115,190
Other	**9,713**	13,685	14,246
Total operating revenues	**268,785**	291,443	258,286
Operating Expenses			
Regulated energy cost of sales	**64,803**	54,789	70,861
Unregulated energy cost of sales	**95,467**	145,854	99,987
Operations	**50,706**	43,476	42,243
Transaction-related costs	**1,478**	1,153	
Maintenance	**3,430**	2,215	2,236
Depreciation and amortization	**11,588**	9,005	9,060
Other taxes	**7,577**	6,472	5,785
Total operating expenses	**235,049**	262,964	230,172
Operating Income	**33,736**	28,479	28,114
Other income, net of other expenses	**165**	103	291
Interest charges	**7,086**	6,158	6,590
Income Before Income Taxes	**26,815**	22,424	21,815
Income taxes	**10,918**	8,817	8,597
Net Income from continuing operations	**15,897**	13,607	13,218
Loss from discontinued operations, net of tax benefit of $0, $0 and $11			(20)
Net Income	**$ 15,897**	$ 13,607	$ 13,198
Weighted Average Common Shares Outstanding:			
Basic	**7,313,320**	6,811,848	6,743,041
Diluted	**7,440,201**	6,927,483	6,854,716
Earnings Per Share of Common Stock:			
Basic			
From continuing operations	**$ 2.17**	$ 2.00	$ 1.96
From discontinued operations			

Net Income	**$**	**2.17**	$	2.00	$	1.96
Diluted						
From continuing operations	**$**	**2.15**	$	1.98	$	1.94
From discontinued operations						
Net Income	**$**	**2.15**	$	1.98	$	1.94
Cash Dividends Declared Per Share of Common Stock	**$**	**1.250**	$	1.210	$	1.175

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

Table of Contents

Consolidated Statements of Cash Flows

For the Years Ended December 31, *(in thousands)*	**2009**	2008	2007
Operating Activities			
Net Income	**$ 15,897**	$ 13,607	$ 13,198
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**11,588**	9,005	9,060
Depreciation and accretion included in other costs	**2,789**	2,239	3,337
Deferred income taxes, net	**10,065**	11,442	1,831
Gain on sale of assets			(205)
Unrealized (gain) loss on commodity contracts	**1,606**	(1,252)	(65)
Unrealized (gain) loss on investments	**(212)**	509	(123)
Employee benefits and compensation	**1,217**	152	1,004
Share based compensation	**1,306**	820	990
Other, net	**(40)**	4	
Changes in assets and liabilities:			
Sale (purchase) of investments	**(146)**	(201)	229
Accounts receivable and accrued revenue	**(13,652)**	19,411	(28,189)
Propane inventory, storage gas and other inventory	**2,597**	(1,730)	1,193
Regulatory assets	**(1,842)**	411	(345)
Prepaid expenses and other current assets	**(747)**	(1,182)	(1,186)
Other deferred charges	**(83)**	(153)	(2,478)
Long-term receivables	**191**	207	84
Accounts payable and other accrued liabilities	**10,185**	(15,033)	22,024
Income taxes receivable	**5,020**	(6,155)	(159)
Accrued interest	**66**	158	33
Customer deposits and refunds	**(75)**	(502)	2,535
Accrued compensation	**(2,066)**	(175)	946
Regulatory liabilities	**1,071**	(3,107)	2,124
Other liabilities	**1,074**	69	(157)
Net cash provided by operating activities	**45,809**	28,544	25,681
Investing Activities			
Property, plant and equipment expenditures	**(26,603)**	(30,756)	(31,277)
Proceeds from sale of assets			205
Proceeds from investments	**3,519**		
Cash acquired in the merger, net of cash paid	**359**		
Environmental expenditures	**(418)**	(480)	(228)
Net cash used by investing activities	**(23,143)**	(31,236)	(31,300)
Financing Activities			
Common stock dividends	**(7,957)**	(7,810)	(7,030)
Issuance of stock for Dividend Reinvestment Plan	**392**	(118)	299

Change in cash overdrafts due to outstanding checks		**835**		(684)		(541)
Net borrowing (repayment) under line of credit agreements		**(3,812)**		(11,980)		18,651
Proceeds from issuance of long-term debt				29,961		
Repayment of long-term debt		**(10,907)**		(7,658)		(7,656)
Net cash provided by (used in) financing activities		**(21,449)**		1,711		3,723
Net Increase (Decrease) in Cash and Cash Equivalents		**1,217**		(981)		(1,896)
Cash and Cash Equivalents Beginning of Period		**1,611**		2,592		4,488
Cash and Cash Equivalents End of Period	**$**	**2,828**	$	1,611	$	2,592

Supplemental Cash Flow Disclosures (see Note D)

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

Table of Contents

Consolidated Balance Sheets

Assets *(in thousands, except shares and per share data)*	December 31, 2009	December 31, 2008
Property, Plant and Equipment		
Regulated energy	**$ 463,856**	$ 316,125
Unregulated energy	**61,360**	51,827
Other	**16,054**	12,255
Total property, plant and equipment	**541,270**	380,207
Less: Accumulated depreciation and amortization	**(107,318)**	(101,018)
Plus: Construction work in progress	**2,476**	1,482
Net property, plant and equipment	**436,428**	280,671
Investments	**1,959**	1,601
Current Assets		
Cash and cash equivalents	**2,828**	1,611
Accounts receivable (less allowance for uncollectible accounts of $1,609 and $1,159, respectively)	**70,029**	52,905
Accrued revenue	**12,838**	5,168
Propane inventory, at average cost	**7,901**	5,711
Other inventory, at average cost	**3,149**	1,479
Regulatory assets	**1,205**	826
Storage gas prepayments	**6,144**	9,492
Income taxes receivable	**2,614**	7,443
Deferred income taxes	**1,498**	1,578
Prepaid expenses	**5,843**	4,679
Mark-to-market energy assets	**2,379**	4,482
Other current assets	**147**	147
Total current assets	**116,575**	95,521
Deferred Charges and Other Assets		
Goodwill	**34,095**	674
Other intangible assets, net	**3,951**	164
Long-term receivables	**343**	533
Regulatory assets	**19,860**	2,806
Other deferred charges	**3,891**	3,825
Total deferred charges and other assets	**62,140**	8,002

Total Assets	**$**	**617,102**	$	385,795

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

Table of Contents

Consolidated Balance Sheets

Capitalization and Liabilities *(in thousands, except shares and per share data)*	December 31, 2009	December 31, 2008
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 12,000,000 shares)	**$ 4,572**	$ 3,323
Additional paid-in capital	**144,502**	66,681
Retained earnings	**63,231**	56,817
Accumulated other comprehensive loss	**(2,524)**	(3,748)
Deferred compensation obligation	**739**	1,549
Treasury stock	**(739)**	(1,549)
Total stockholders equity	**209,781**	123,073
Long-term debt, net of current maturities	**98,814**	86,422
Total capitalization	**308,595**	209,495
Current Liabilities		
Current portion of long-term debt	**35,299**	6,656
Short-term borrowing	**30,023**	33,000
Accounts payable	**51,948**	40,202
Customer deposits and refunds	**24,960**	9,534
Accrued interest	**1,887**	1,024
Dividends payable	**2,959**	2,082
Accrued compensation	**3,445**	3,305
Regulatory liabilities	**8,882**	3,227
Mark-to-market energy liabilities	**2,514**	3,052
Other accrued liabilities	**8,683**	2,970
Total current liabilities	**170,600**	105,052
Deferred Credits and Other Liabilities		
Deferred income taxes	**66,923**	37,720
Deferred investment tax credits	**193**	235
Regulatory liabilities	**4,154**	875
Environmental liabilities	**11,104**	511
Other pension and benefit costs	**17,505**	7,335
Accrued asset removal cost Regulatory liability	**33,214**	20,641
Other liabilities	**4,814**	3,931
Total deferred credits and other liabilities	**137,907**	71,248

Other commitments and contingencies (Note P)				
Total Capitalization and Liabilities	**$**	**617,102**	$	385,795

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

Table of Contents

Consolidated Statements of Stockholders Equity

(in thousands, except per share and share data)	Common Stock Number of Shares [7]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2006	**6,688,084**	**$ 3,255**	**$ 61,960**	**$ 46,271**	**$ (334)**	**$ 1,119**	**$ (1,119)**	**$ 111,152**
Net Income				13,198				13,198
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					(3)			(3)
Net loss [5]					(515)			(515)
Total comprehensive income								12,680
Dividend Reinvestment Plan	35,333	17	1,121					1,138
Retirement Savings Plan	29,563	14	935					949
Conversion of debentures	8,106	4	135					139
Share based compensation [1] [3]	16,324	8	1,442					1,450
Deferred Compensation Plan						285	(285)	
Purchase of treasury stock	(971)						(30)	(30)
Sale and distribution of treasury stock	971						30	30
Cash dividends [2]				(7,931)				(7,931)
Balances at December 31, 2007	**6,777,410**	**3,298**	**65,593**	**51,538**	**(852)**	**1,404**	**(1,404)**	**119,577**
Net Income				13,607				13,607
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					(71)			(71)
Net loss [5]					(2,825)			(2,825)
Total comprehensive income								10,711
Dividend Reinvestment Plan	9,060	5	269					274
Retirement Savings Plan	5,260	3	156					159
Conversion of debentures	10,397	5	171					176
Share based compensation [1] [3]	24,994	12	442					454
Tax benefit on stock warrants			50					50
Deferred Compensation Plan						145	(145)	
Purchase of treasury stock	(2,425)						(72)	(72)
Sale and distribution of treasury stock	2,425						72	72
Dividends on stock-based compensation				(81)				(81)
Cash dividends [2]				(8,247)				(8,247)
Balances at December 31, 2008	**6,827,121**	**3,323**	**66,681**	**56,817**	**(3,748)**	**1,549**	**(1,549)**	**123,073**
Net Income				15,897				15,897
Other comprehensive income, net of tax:								

Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					7			7
Net Gain [5]					1,217			1,217
Total comprehensive income								17,121
Dividend Reinvestment Plan	31,607	15	921					936
Retirement Savings Plan	32,375	16	966					982
Conversion of debentures	7,927	4	131					135
Share based compensation [1] [3]	7,374	3	1,332					1,335
Deferred Compensation Plan [6]						(810)	810	
Purchase of treasury stock	(2,411)						(73)	(73)
Sale and distribution of treasury stock	2,411						73	73
Common stock issued in the merger	2,487,910	1,211	74,471					75,682
Dividends on stock-based compensation				(104)				(104)
Cash dividends [2]				(9,379)				(9,379)
Balances at December 31, 2009	**9,394,314**	**$ 4,572**	**$ 144,502**	**$ 63,231**	**$ (2,524)**	**$ 739**	**$ (739)**	**$ 209,781**

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

(2) Cash dividends per share for the periods ended December 31, 2009, 2008 and 2007 were $1.250, $1.210 and $1.175 respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For 2008 and 2007, the Company withheld 12,511 and 2,420 respectively shares for taxes. The Company did not issue any shares for the PIP in 2009.

(4) Tax expense (benefit) recognized

on the prior service cost component of employees benefit plans for the periods ended December 31, 2009, 2008 and 2007 were approximately $5, ($52) and ($2) respectively.

(5) Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended December 31, 2009, 2008 and 2007 were $794, ($1,900) and ($340) respectively.

(6) In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in 2008 and 2007.

(7) Includes 28,452, 62,221 and 57, 309 shares at December 31, 2009, 2008 and 2007, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

Notes to the Consolidated Financial Statements

A. Summary of Accounting Policies

Nature of Business

Chesapeake, incorporated in 1947 in Delaware, is a diversified utility company engaged in regulated energy, unregulated energy and other unregulated businesses. On October 28, 2009, we completed a merger with FPU, pursuant to which FPU became a wholly-owned subsidiary of Chesapeake. Our regulated energy business delivers natural gas to approximately 118,000 customers located in central and southern Delaware, Maryland s Eastern Shore and Florida and electricity to approximately 31,000 customers in northeast and northwest Florida. Our regulated energy business also provides natural gas transmission service primarily through a 384-mile interstate pipeline from various points in Pennsylvania and northern Delaware to our natural gas distribution affiliates in Delaware and Maryland as well as to other utility and industrial customers in Pennsylvania, Delaware and the Eastern Shore of Maryland.

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

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

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries. As a result of the merger with FPU on October 28, 2009, FPU s financial position, results of operations and cash flows have been consolidated into our results from the effective date of the merger. We do not have any ownership interests in investments accounted for using the equity method or any variable interests in a variable interest entity. All intercompany transactions have been eliminated in consolidation.

System of Accounts

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

Property, Plant, Equipment and Depreciation

Property, plant and equipment is stated at original cost less accumulated depreciation or fair value, if impaired. Property, plant and equipment acquired in the merger were stated at fair value at the time of the merger. Costs include direct labor, materials and third-party construction contractor costs, allowance for capitalized interest and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged against income as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property of unregulated businesses, the gain or loss, net of salvage value, is charged to income. Upon retirement or disposition of property of regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. The provision for depreciation is computed using the straight-line method at rates that amortize the unrecovered cost of depreciable property over the estimated remaining useful life of the asset. Depreciation and amortization expenses for the regulated energy operations are provided at various annual rates, as approved by the regulators.

Table of Contents

(In thousands)	December 31, 2009	December 31, 2008	Useful Life (1)
Plant in service			
Mains	**$ 237,133**	$ 184,125	27-62 years
Services utility	**61,803**	37,947	12-48 years
Compressor station equipment	**24,981**	24,981	42 years
Liquefied petroleum gas equipment	**30,211**	26,304	5-31 years
Meters and meter installations	**28,419**	19,479	Unregulated energy 3-33 years, regulated energy 14-49 years
Measuring and regulating station equipment	**19,131**	15,092	14-54 years
Office furniture and equipment	**15,587**	12,536	Unregulated energy 4-7 years, regulated energy14-25 years
Transportation equipment	**16,805**	11,267	1-20 years
Structures and improvements	**15,007**	10,602	3-44 years (2)
Land and land rights	**12,789**	7,901	Not depreciable, except certain regulated assets
Propane bulk plants and tanks	**12,181**	6,296	12-40 years
Electric transmission lines and transformers	**29,736**		10-41 years
Poles and towers	**8,752**		21-40 years
Various	**28,735**	23,677	Various
Total plant in service	**541,270**	380,207	
Plus construction work in progress	**2,476**	1,482	
Less accumulated depreciation	**(107,318)**	(101,018)	
Net property, plant and equipment	**$ 436,428**	$ 280,671	

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

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

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

(2) Includes buildings, structures used

in connection with natural gas, electric and propane operations, improvements to those facilities and leasehold improvements.

Plant in service includes $1.4 million of assets owned by one of our natural gas transmission subsidiaries, which it uses to provide natural gas transmission service under a contract with a third-party. This contract is accounted for as an operating lease due to exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and provides $264,000 in annual revenues for a term of 20 years. Accumulated depreciation for these assets total $74,000 at December 31, 2009.

Cash and Cash Equivalents

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

Table of Contents

Inventories

We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to market values.

Regulatory Assets, Liabilities and Expenditures

We account for our regulated operations in accordance with ASC Topic 980, Regulated Operations. This Topic includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions, the economics of which require companies to defer costs or revenues in different periods than may be appropriate for unregulated enterprises. When this situation occurs, a regulated company defers the associated costs as regulatory assets on the balance sheet and records them as expense on the income statement as it collects revenues. Further, regulators can also impose liabilities upon a regulated company for amounts previously collected from customers, and for recovery of costs that are expected to be incurred in the future as regulatory liabilities.

At December 31, 2009 and 2008, the regulated utility operations had recorded the following regulatory assets and liabilities on the Balance Sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers rates.

(in thousands)	**December 31, 2009**	December 31, 2008
Regulatory Assets		
Underrecovered purchased gas costs	**$ 1,149**	$ 651
Income tax related amounts due from customers	**1,783**	1,285
Deferred post retirement benefits	**3,636**	83
Deferred transaction and transition costs	**1,486**	
Deferred piping and conversion costs	**1,061**	
Deferred development costs	**1,698**	
Environmental regulatory assets and expenditures	**7,510**	779
Acquisition adjustment (1)	**795**	
Loss on reacquired debt	**154**	
Other	**1,793**	834
Total Regulatory Assets	**$ 21,065**	$ 3,632
Regulatory Liabilities		
Self insurance	**$ 982**	$ 912
Overrecovered purchased gas costs	**7,304**	1,542
Shared interruptible margins	**84**	232
Conservation cost recovery	**1,035**	744
Rate refund(2)	**258**	
Income tax related amounts due to customers	**729**	125
Storm reserve	**2,554**	
Accrued asset removal cost	**33,214**	20,641
Other	**90**	547
Total Regulatory Liabilities	**$ 46,250**	$ 24,743

(1)

Net carrying value of goodwill from FPU s previous acquisition that is allowed to be amortized pursuant to a rate order.

(2) Refunded to FPU natural gas customers in February 2010.

Included in the regulatory assets listed above is $1.5 million related to deferred merger-related costs at December 31, 2009 for which we intend to seek recovery in future rates in Florida. Also included in the regulatory assets listed above are $838,000 and $711,000 at December 31, 2009 and 2008, respectively, in other costs primarily related to income tax related amounts, for which we are awaiting regulatory approval from various jurisdictions for recovery. For certain regulatory assets, such as under-recovered purchased fuel costs, deferred rate case costs and development costs, only recovery of the deferred costs is allowed in rates and we do not earn a return on those regulatory assets.

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

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually. In addition, goodwill of a reporting unit is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives. Please refer to Note H, Goodwill and Other Intangible Assets, to the Consolidated Financial Statements for additional discussion of this subject.

Other Deferred Charges

Other deferred charges include discount, premium and issuance costs associated with long-term debt. Debt costs are deferred and then are amortized to interest expense over the original lives of the respective debt issuances.

Pension and Other Postretirement Plans

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. Management annually reviews the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities with the assistance of third-party actuarial firms. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rates, health care cost trend rates and rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rates are utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When establishing its discount rates, we consider high quality corporate bond rates based on Moody s Aa bond index, the Citigroup yield curve, changes in those rates from the prior year, and other pertinent factors, such as the expected life of each of our plans and their respective payment options.

The expected long-term rates of return on assets are utilized in calculating the expected returns on plan assets component of our annual pension and plan costs. We estimate the expected returns on plan assets of each of our plans by evaluating expected bond returns, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rates of return on assets.

We estimate the assumed health care cost trend rates used in determining our postretirement net expense based upon actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual reviews of participant census information as of the measurement date.

Table of Contents

Income Taxes and Investment Tax Credit Adjustments

Deferred tax assets and liabilities are recorded for the tax effect of temporary differences between the financial statements bases and tax bases of assets and liabilities and are measured using the enacted tax rates in effect in the years in which the differences are expected to reverse. The portions of our deferred tax liabilities applicable to regulated energy operations, which have not been reflected in current service rates, represent income taxes recoverable through future rates. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such tax benefits will be realized. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

We account for uncertainty in income taxes in the financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the financial statements.

Financial Instruments

Xeron, our propane wholesale marketing operation, engages in trading activities using forward and futures contracts, which have been accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, our trading contracts are recorded at fair value, net of future servicing costs. The changes in market price are recognized as gains or losses in revenues on the consolidated income statement in the period of change. There were unrealized losses of $1.6 million in 2009 and unrealized gains of $1.4 million in 2008. Trading liabilities are recorded in mark-to-market energy liabilities. Trading assets are recorded in mark-to-market energy assets.

Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis. The propane distribution operation may enter into a fair value hedge of its inventory in order to mitigate the impact of wholesale price fluctuations. During 2008, we entered into a swap agreement to protect the Company from the impact that propane price increases would have on the Pro-Cap (propane price cap) Plan that the Delmarva propane distribution operation offers to our customers. Propane prices declined significantly in late 2008 and we recorded a mark-to-market loss of approximately $939,000 on the swap agreement in 2008, which increased the cost of propane sales. In January 2009, we terminated the swap agreement. During 2009, we purchased a put option related to the Pro-Cap Plan, which we accounted for on a mark-to-market basis, and recorded a loss of $41,000. At December 31, 2009 and 2008, we had $0 in fair value of the put agreement and $(105,000) in fair value of the swap agreement, respectively.

Table of Contents

Earnings Per Share

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

For the Years Ended December 31,	**2009**	**2008**	**2007**
(in thousands, except shares and per share data)			
Calculation of Basic Earnings Per Share:			
Net Income	**$ 15,897**	$ 13,607	$ 13,198
Weighted average shares outstanding	**7,313,320**	6,811,848	6,743,041
Basic Earnings Per Share	**$ 2.17**	$ 2.00	$ 1.96
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	**$ 15,897**	$ 13,607	$ 13,198
Effect of 8.25% Convertible debentures	**79**	89	96
Adjusted numerator Diluted	**$ 15,976**	$ 13,696	$ 13,294
Reconciliation of Denominator:			
Weighted shares outstanding Basic	**7,313,320**	6,811,848	6,743,041
Effect of dilutive securities:			
Share-based Compensation	**34,229**	12,083	
8.25% Convertible debentures	**92,652**	103,552	111,675
Adjusted denominator Diluted	**7,440,201**	6,927,483	6,854,716
Diluted Earnings Per Share	**$ 2.15**	$ 1.98	$ 1.94

Common stock issued in connection with the FPU merger (See Note B, Acquisitions and Dispositions, to the Consolidated Financial Statements) increased weighted average shares outstanding during 2009.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSCs of the states in which they operate. The natural gas transmission operation 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 ESNG to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as a recourse 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 the amount of natural gas and electricity that have not been accounted for on our delivery systems and must 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 our consolidated statement of income. For propane distribution customers without meters and advanced information services customers, we record revenue in the period the products are delivered and/or services are rendered.

Table of Contents

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

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

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services provided by the Company for its regulated and unregulated energy segments. These costs include primarily the variable cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, transportation costs to transport propane purchases to our storage facilities, and the direct cost of labor for our advanced information services operation.

Operations and Maintenance Expenses

Operations and maintenance expenses are costs associated with the operation and maintenance of our regulated and unregulated operations. Major cost components include operation and maintenance salaries and benefits, materials and supplies, usage of vehicles, tools and equipment, payments to contractors, utility plant maintenance, customer service, professional fees and other outside services, insurance expense, minor amounts of depreciation, accretion of cost of removal for future retirements of utility assets, and other administrative expenses.

Depreciation and Accretion Included in Operations Expenses

Depreciation and accretion included in operations expenses consist of the accretion of the costs of removal for future retirement of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense.

Allowance for Doubtful Accounts

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

Certain Risks and Uncertainties

Our financial statements are prepared in conformity with GAAP, which require management to make estimates in measuring assets and liabilities and related revenues and expenses (see Note O, Environmental Commitments and Contingencies, and Note P, Other Commitments and Contingencies, to the Consolidated Financial Statements for significant estimates). These estimates involve judgments with respect to, among other things, various future economic factors that are difficult to predict and are beyond the control of the Company; therefore, actual results could differ from those estimates.

We record certain assets and liabilities in accordance with ASC Topic 980, Regulated Operations. In applying provisions of this Topic, our regulated operations may defer costs or revenues in different periods than our unregulated operations would recognize, resulting in their being recorded as assets or liabilities on the applicable operation s balance sheet. If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the income statement at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material.

Acquisition Accounting

The merger with FPU was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer. The acquisition method of accounting requires, among other things, that the assets acquired and liabilities assumed in the merger be recognized at their fair value as of the acquisition date. It also establishes that the consideration transferred be measured at the closing date of the merger at the then-current market price. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In addition, market participants are assumed to be buyers and sellers in the principal (or the most advantageous) market for the asset or liability and fair value measures for an asset assume the highest and best use by those market participants, rather than the acquirer s intended use of those assets. Many of these fair value measurements can be highly subjective and it is also possible that others applying reasonable judgment to the same facts and circumstances could develop and support a range of alternative estimated amounts. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature and impact of such regulations on those assets and liabilities as a factor in determining their appropriate fair value. We also considered the existence of a regulatory process that would allow, or sometimes require, regulatory assets and liabilities to be established for fair value adjustment to certain assets and liabilities subject to rate regulation. If a regulatory asset or liability should be established to offset the fair value adjustment based on the current regulatory process, as was the case for fuel contracts and long-term debt, we did not gross-up our balance sheet to reflect the fair value adjustment and corresponding regulatory asset/liability, because such gross-up would not have resulted in a change to the value of net assets and future earnings of the Company.

Total value of the consideration transferred by Chesapeake in the merger was $75.7 million. Net fair value of the assets acquired and liabilities assumed in the merger was estimated to be $42.3 million. This resulted in a purchase premium of $33.4 million, which was reflected as goodwill. Note B, Acquisitions and Dispositions, to the Consolidated Financial Statements describes more fully the purchase price allocation.

The acquisition method of accounting also requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of considerations transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger for the acquiree. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining proper accounting treatment for the merger-related costs. During 2009, we incurred approximately $3.0 million to consummate the merger, including the cost associated with merger-related litigation, and integrate operations following the merger. We deferred approximately $1.5 million of the total costs incurred as a regulatory asset at December 31, 2009, which represents our estimate, based on similar proceedings in Florida in the past, of the costs which we expect to be permitted to recover when we complete the appropriate rate proceedings.

Subsequent Events

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

Reclassifications

As a result of the merger with FPU in 2009, we changed our operating segments (see Note C, Segment Information, to the Consolidated Financial Statements). We revised the 2008 and 2007 segment information to reflect the new segments. We also revised the 2008 segment information by reclassifying transaction costs, which were previously allocated to all segments, to the Other segment. We reclassified certain amounts in the statements of income and cash flows for the years ended December 31, 2008 and 2007, to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our Consolidated Financial Statements.

Table of Contents

Codification

Beginning in the third quarter of 2009, we adopted the Financial Accounting Standards Board (FASB) ASC, which is now the single source of authoritative accounting principles in the United States. The adoption of the ASC did not have a material impact on our financial position and results of operations. As a result of this adoption, we updated all references to accounting and reporting standards included in this Form 10-K and in some instances provided references to both pre-and post-Codification standards, as appropriate.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Pronouncements Yet to be Adopted by the Company

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards (IFRS), a comprehensive series of accounting standards published by the International Accounting Standards Board (IASB). Under the proposed roadmap, we may be required to prepare financial statements in accordance with IFRS as early as 2014. The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS. In July 2009, the IASB issued an exposure draft of Rate-regulated Activities, which sets out the scope, recognition and measurement criteria, and accounting disclosures for assets and liabilities that arise in the context of cost-of-service regulation, to which we are subject in our rate-regulated businesses. We will continue to monitor the development of the potential implementation of IFRS.

The FASB has issued ASU 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This ASU requires some new disclosures and clarifies some existing disclosure requirements about fair value measurement as set forth in ASC Subtopic 820-10. The FASB s objective is to improve these disclosures and, thus, increase the transparency in financial reporting. Specifically, ASU 2010-06 amends ASC Subtopic 820-10 to now require a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers; and in the reconciliation for fair value measurements using significant unobservable inputs, a reporting entity should present separately information about purchases, sales, issuances, and settlements. In addition, ASU 2010-06 clarifies certain requirements of the existing disclosures. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. We are currently assessing the potential impact of this pronouncement.

Other Accounting Amendments Adopted by the Company in 2009:

In December 2007, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 141(R), now codified within ASC Topic 805, Business Combinations. SFAS No.141(R): (a) defines the acquirer as the entity that obtains control of one or more businesses in a business combination; (b) establishes the acquisition date as the date that the acquirer achieves control; and (c) requires the acquirer to recognize the assets acquired, liabilities assumed and any non-controlling interests at their fair values as of the acquisition date. It also requires that acquisition-related costs be expensed as incurred. Provisions of this standard were adopted effective January 1, 2009. The merger with FPU, effective October 28, 2009, was accounted for using provisions of this standard. For further discussion, see Note B, Acquisition and Dispositions to the Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 was codified within ASC Sections 815-10-15 and 65, of the Topic, Derivatives and Hedging, and it requires enhanced disclosures for derivative instruments and hedging activities including: (i) how and why a company uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for under the Derivatives and Hedging Topic, and (iii) how derivative instruments and related hedged items affect a company s financial position, financial performance and cash flows. Disclosures required by this standard were adopted by the Company, effective January 1, 2009. Adoption of this standard did not have an impact on our consolidated financial position and results of operations. These disclosures are discussed in Note E, Derivative Instruments, to the Consolidated Financial Statements.

Table of Contents

In April 2008, the FASB issued FASB Staff Position (FSP) FAS 142-3, Determination of the Useful Life of Intangible Assets, which is codified within ASC Sections 350-30-50, 55 and 65 of the Topic, Intangibles Goodwill and Other, and ASC Section 275-10-50, of the Topic, Risks and Uncertainties. It amended factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The intent of these provisions is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. We adopted this standard, effective January 1, 2009. Adoption of this standard did not have an impact on our consolidated financial position and results of operations.

In May 2008, the FASB issued FSP APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement), which was codified within: (a) ASC Sections 470-20-10, 15, 25, 30, 35, 40, 45, 50, 55 and 65 of the Topic, Debt, (b) ASC Section 815-15-55, of the Topic, Derivatives and Hedging, and (c) ASC Section 825-10-15, of the Topic, Financial Instruments. FSP APB 14-1 clarifies that companies with convertible debt instruments, which may be settled in cash upon either mandatory or optional conversion (including partial cash settlement), should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. We adopted this standard, effective, January 1, 2009. The adoption of this standard did not have an impact on our consolidated financial position and results of operations.

In September 2008, the FASB issued FSP Emerging Issues Task Force 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. This FSP, codified within FASB ASC Sections 260-10-45, 55 and 65, of the Topic, Earnings Per Share, clarifies that holders of outstanding unvested share-based payment awards containing rights to nonforfeitable dividends participate with common shareholders in undistributed earnings. Awards of this nature are considered participating securities, and the two-class method of computing basic and diluted earnings per share must be applied. We adopted this standard, effective January 1, 2009. The adoption of this standard did not have an impact on our consolidated financial position and results of operations.

In December 2008, the FASB issued FSP SFAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets. This FSP is codified within ASC Section 715-20-65, of the Topic, Compensation Retirement Benefits. It expands the disclosure requirements of a defined benefit pension or other postretirement plan by including the following discussions about plan assets: (i) how investment allocation decisions are made, including the plan s investment policies and strategies; (ii) the major categories of plan assets; (iii) the inputs and valuation techniques used to measure the fair value of plan assets; (iv) the effect of fair value measurements, using significant unobservable inputs on changes in plan assets for the period; and (v) significant concentrations of risk within plan assets. The disclosures required by this standard are discussed in Note M, Employee Benefit Plans, to the Consolidated Financial Statements.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FSP, codified within ASC Section 825-10-65 of the Topic, Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. The provisions of this standard are effective for interim and annual reporting periods ending after June 15, 2009, and they did not have an impact on our consolidated financial position and results of operations. The disclosures required by this standard are discussed in Note F, Fair Value of Financial Instruments, to the Consolidated Financial Statements.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events, which we adopted in the second quarter of 2009. The provisions of this standard, now residing in ASC Sections 855-10-05, 15, 25, 45, 50 and 55 of the Topic, Subsequent Events, establish general standards of accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The adoption of this standard did not have an impact on our consolidated financial position and results of operations.

In August 2009, the FASB issued FASB Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurement and Disclosures Measuring Liabilities at Fair Value. This ASU provides clarification that in circumstances in which a quoted price in an active market for an identical liability is not available, a reporting entity is required to measure fair value, using either: (a) a valuation technique that applies the quoted price of the identical liability when traded as an asset or quoted prices for similar liabilities when traded as assets; or (b) another valuation technique that is consistent with the principles of the Topic, Fair Value Measurements and Disclosures. We adopted this ASU in the third quarter of 2009, and the adoption of this standard did not have an impact on our consolidated financial position and results of operations.

B. Acquisitions and Dispositions

FPU

On October 28, 2009, we completed the previously announced merger with FPU, pursuant to which FPU became a wholly-owned subsidiary of Chesapeake. The merger was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer for accounting purposes.

The merger allowed us to become a larger energy company serving approximately 200,000 customers in the Mid-Atlantic and Florida markets, which is twice the number of energy customers we served previously. The merger increases our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing operations in Florida. It also introduces us to the electric distribution business as we incorporate FPU s approximately 31,000 electric customers in northwest and northeast Florida.

In consummating the merger, we issued 2,487,910 shares of Chesapeake common stock at a price per share of $30.42 in exchange for all outstanding common stock of FPU. We also paid approximately $16,000 in lieu of issuing fractional shares in the exchange. There is no contingent consideration in the merger. Total value of considerations transferred by Chesapeake in the merger was approximately $75.7 million.

The assets acquired and liabilities assumed in the merger were recorded at their respective fair values at the completion of the merger. For certain assets acquired and liabilities assumed, such as pension and post-retirement benefit obligations, income taxes and contingencies without readily determinable fair value, for which GAAP provides specific exception to the fair value recognition and measurement, we applied other specified GAAP or accounting treatment as appropriate.

The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the merger. Estimates of deferred income taxes and certain accruals are subject to change, pending the finalization of income tax returns and availability of additional information about the facts and circumstances that existed as of the merger closing. We will complete the purchase price allocation as soon as practicable but no later than one year from the merger closing.

Table of Contents

(in thousands)	October 28, 2009
Purchase price	$ 75,699
Current assets	26,761
Property, plant and equipment	141,907
Regulatory assets	17,918
Investments and other deferred charges	3,659
Intangible assets	4,019
Total assets acquired	194,264
Long term debt	47,812
Borrowings from line of credit	4,249
Other current liabilities	17,504
Other regulatory liabilities	19,414
Pension and post retirement obligations	14,276
Environmental liabilities	12,414
Deferred income taxes	20,850
Customer deposits and other liabilities	15,467
Total liabilities assumed	151,986
Net identifiable assets acquired	42,278
Goodwill	$ 33,421

Goodwill of $33.4 million was recorded in connection with the merger, none of which is deductible for tax purposes. All of the goodwill recorded in connection with the merger is related to the regulated energy segment. We believe the goodwill recognized is attributable primarily to the strength of FPU s regulated energy businesses and the synergies and opportunities in the combined company. Intangible assets acquired in connection with the merger are related to propane customer relationships ($3.5 million) and favorable propane contracts ($519,000). The intangible value assigned to FPU s existing propane customer relationships will be amortized over a 12-year period based on the expected duration of benefit arising from the relationships. The intangible value assigned to favorable propane contracts, will be amortized over a period ranging from one to 14 months based on contractual terms. See Note H, Goodwill and Other Intangible Assets, to the Consolidated Financial Statements.

Current assets of $26.7 million acquired during the merger include notes receivable of approximately $5.8 million, for which we expect to receive payment in March 2010, and accounts receivable of approximately $3.1 million, $6.0 million and $891,000 for natural gas, electric and propane distribution businesses, respectively.

The financial position and results of operations and cash flows of FPU from the effective date of the merger are consolidated in our Consolidated Financial Statements in 2009. The revenue and net income from FPU for the post-merger period in 2009 included in our Consolidated Statements of Income were $26.4 million and $1.8 million, respectively. The following table shows pro forma results of operations for the year ended December 31, 2009, as if the merger had been completed at January 1, 2009, as well as pro forma results of operations for the year ended December 31, 2008, as if the merger had been completed at January 1, 2008.

Table of Contents

For the Years Ended December 31, *(in thousands, except per share data)*	**2009**	2008
Operating revenues	**$ 394,772**	$ 451,292
Operating Income	**44,382**	38,468
Net Income	**20,872**	17,544
Earnings per share basic	**$ 2.23**	$ 1.89
Earnings per share diluted	**$ 2.20**	$ 1.86

Pro forma results are presented for informational purposes only, and are not necessarily indicative of what the actual results would have been had the acquisitions actually occurred on January 1, 2009, and January 1, 2008, respectively.

OnSight

During 2007, we decided to close our distributed energy services subsidiary, OnSight, which had experienced operating losses since its inception in 2004. The results of operations for OnSight have been reclassified to discontinued operations and shown net of tax for all periods presented. The discontinued operations experienced a net loss of $20,000 for 2007. We did not have any discontinued operations in 2008 and 2009.

C. Segment Information

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

As a result of the merger with FPU, we changed our operating segments to better align with how the chief operating decision maker views the various operations of the Company. Our three operating segments are now composed of the following:

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

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.

We also reclassified the segment information for 2008 and 2007 to reflect the new segments. During 2009, we also decided not to allocate merger-related transaction costs to different operations for the purpose of reporting their operating profitability because such costs are not directly attributable to their operations. To conform to the current year s presentation, we revised the 2008 segment information by reclassifying transaction costs, which were previously allocated to all segments, to the Other segment.

Table of Contents

The following table presents information about our reportable segments. The table excludes financial data related to its former distributed energy service subsidiary, OnSight, which was reclassified to discontinued operations for 2007.

For the Years Ended December 31, *(in thousands)*	**2009**	2008	2007
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 137,847**	$ 115,544	$ 128,491
Unregulated Energy	**119,719**	161,287	115,190
Other	**11,219**	14,612	14,606
Total operating revenues, unaffiliated customers	**$ 268,785**	$ 291,443	$ 258,287
Intersegment Revenues (1)			
Regulated Energy	**$ 1,252**	$ 924	$ 359
Unregulated Energy	**254**	3	
Other	**779**	761	$ 1,115
Total intersegment revenues	**$ 2,285**	$ 1,688	$ 1,474
Operating Income			
Regulated Energy	**$ 26,900**	$ 24,733	$ 21,809
Unregulated Energy	**8,158**	3,781	5,174
Other	**(1,322)**	(35)	1,131
Operating Income	**33,736**	28,479	28,114
Other income	**165**	103	291
Interest charges	**7,086**	6,158	6,590
Income taxes	**10,918**	8,817	8,597
Net income from continuing operations	**$ 15,897**	$ 13,607	$ 13,218
Depreciation and Amortization			
Regulated Energy	**$ 8,866**	$ 6,694	$ 6,918
Unregulated Energy	**2,415**	2,024	1,842
Other	**307**	287	300
Total depreciation and amortization	**$ 11,588**	$ 9,005	$ 9,060
Capital Expenditures			
Regulated Energy	**$ 22,917**	$ 25,386	$ 23,087
Unregulated Energy	**1,873**	3,417	5,290
Other	**1,504**	2,041	1,765

Total capital expenditures	**$**	**26,294**	$	30,844	$	30,142

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

(in thousands)		**December 31, 2009**		**December 31, 2008**
Identifiable Assets				
Regulated Energy	**$**	**480,903**	$	297,407
Unregulated Energy		**101,437**		72,955
Other		**34,724**		15,394
Total identifiable assets	**$**	**617,064**	$	385,756

Table of Contents

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

D. Supplemental Cash Flow Disclosures

Cash paid for interest and income taxes during the years ended December 31, 2009, 2008, and 2007 were as follows:

For the Years Ended December 31,	2009	2008	2007
(in thousands)			
Cash paid for interest	**$ 6,703**	$ 5,835	$ 5,592
Cash paid for income taxes	**$ 1,111**	$ 3,885	$ 7,009

Non-cash investing and financing activities during the years ended December 31, 2009, 2008, and 2007 were as follows:

For the Years Ended December 31,	2009	2008	2007
(in thousands)			
Capital property and equipment acquired on account, but not paid as of December 31	**$ 1,151**	$ 696	$ 366
Merger with FPU	**$ 75,682**	$	$
Retirement Savings Plan	**$ 982**	$ 159	$ 949
Dividends Reinvestment Plan	**$ 692**	$ 208	$ 841
Conversion of Debentures	**$ 135**	$ 177	$ 138
Performance Incentive Plan	**$**	$ 568	$ 435
Director Stock Compensation Plan	**$ 214**	$ 181	$ 184
Tax benefit on stock warrants	**$**	$ 50	$

E. Derivative Instruments

As of December 31, 2009, we had the following outstanding trading contracts which we accounted for as derivatives:

At December 31, 2009	Quantity in gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	11,944,800	$ 0.6900	$1.3350	$ 1.1264
Purchase	11,256,000	$ 0.7275	$1.3350	$ 1.1367
Other Contract				
Put option	1,260,000	$		$ 0.1500

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

All contracts expire in the first quarter of 2010.

Table of Contents

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.
Fair values of the derivative contracts recorded in the Consolidated Balance Sheet as of December 31, 2009 and 2008, are the following:

		Asset Derivatives Fair Value	
(in thousands)	**Balance Sheet Location**	**December 31, 2009**	**December 31, 2008**
Derivatives not designated as fair value hedges:			
Forward contracts	Mark-to-market energy assets	**$ 2,379**	$ 4,482
Put option[1]	Mark-to-market energy assets		
Total asset derivatives		**$ 2,379**	$ 4,482

		Liability Derivatives Fair Value	
(in thousands)	**Balance Sheet Location**	**December 31, 2009**	**December 31, 2008**
Derivatives designated as fair value hedges:			
Propane swap agreement [2]	Other current liabilities	**$**	$ 105
Derivatives not designated as fair value hedges:			
Forward contracts	Mark-to-market energy liabilities	**2,514**	3,052
Total liability derivatives		**$ 2,514**	$ 3,157

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

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

The effects of gains and losses from derivative instruments on the Consolidated Statement of Income for the years ended December 31, 2009 and 2008, are the following:

		Amount of Gain (Loss) on Derivatives:	
	Location of Gain	**For the Years Ended December 31,**	
(in thousands)	**(Loss) on Derivatives**	**2009**	**2008**
Derivatives designated as fair value hedges			
Propane swap agreement [1]	Cost of Sales	**$ (42)**	$ 1,476
Derivatives not designated as fair value hedges			
Put Option [2]	Revenue	**(41)**	
Derivatives not designated as fair value hedges			
Unrealized gains (losses) on forward contracts	Revenue	**(1,565)**	1,357
Total		**$ (1,648)**	$ 2,833

(1) Our propane distribution operation entered into a propane swap agreement to protect it from the impact that wholesale propane price increases would

have on the Pro-Cap (propane price cap) Plan that was offered to customers. We terminated this swap agreement in January 2009.

(2) We purchased a put option for the Pro-Cap plan in September 2009. The put option, which expires on March 31, 2010, had a fair value of $0 at December 31, 2009.

Table of Contents

The effects of trading activities on the Consolidated Statement of Income for the years ended December 31, 2009 and 2008, are the following:

(in thousands)	Location in the Statement of Income	Amount of Trading Revenue: For the Years Ended December 31, 2009	2008
Realized gains on forward contracts	Revenue	**$ 3,830**	$ 1,935
Unrealized gains (losses) on forward contracts	Revenue	**(1,565)**	1,357
Total		**$ 2,265**	$ 3,292

F. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2009:

		Fair Value Measurements Using:		
(in thousands)	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments	$ 1,959	$ 1,959	$	$
Mark-to-market energy assets, including put option	$ 2,379	$	$ 2,379	$
Liabilities:				
Mark-to-market energy liabilities	$ 2,514	$	$ 2,514	$

Table of Contents

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2008:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments	$ 1,601	$ 1,601	$	$
Mark-to market energy assets	$ 4,482	$	$ 4,482	$
Liabilities:				
Mark-to market energy liabilities	$ 3,052	$	$ 3,052	$
Propane swap agreement	$ 105	$	$ 105	$

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of December 31, 2009 and 2008:

Level 1 Fair Value Measurements:

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

Level 2 Fair Value Measurements:

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

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

At December 31, 2009, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The carrying value of these financial assets and liabilities approximates fair value due to their short maturities and because interest rates approximate current market rates for short-term debt.

At December 31, 2009, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $134.1 million, compared to a fair value of $145.5 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, and risk profile. At December 31, 2008, the estimated fair value was approximately $92.3 million, compared to a carrying value of $93.1 million.

G. Investments

The investment balances at December 31, 2009 and 2008 represent a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan and a Rabbi Trust related to a stay bonus agreement with a former executive. We classify these investments as trading securities and report them at their fair value. Any unrealized gains and losses, net of other expenses, are included in other income in the consolidated statements of income. We also have an associated liability that is recorded and adjusted each month for the gains and losses incurred by the Rabbi Trusts. At December 31, 2009 and 2008, total investments had a fair value of $2.0 million and $1.6 million, respectively.

Table of Contents

H. Goodwill and Other Intangible Assets

On October 28, 2009, we completed the merger with FPU, which resulted in $33.4 million in goodwill, for the regulated energy segment. The regulated energy segment did not have goodwill prior to the merger. As of December 31, 2009 and 2008, the unregulated energy segment reported $674,000 in goodwill. No goodwill was recorded in the unregulated energy segment as a result of the merger with FPU. We test for impairment of goodwill at least annually. The impairment testing for 2009 and 2008 indicated no impairment of goodwill.

We intend to seek recovery of the purchase premium related to the regulated operations through future rates in Florida. If and when approval is obtained from the Florida PSC to recover all or part of the purchase premium in future rates from customers, we will reclassify that portion of goodwill, for which recovery has been authorized, to a regulatory asset.

The carrying value and accumulated amortization of intangible assets subject to amortization for the years ended December 31, 2009 and 2008 are as follows:

	December 31, 2009		**December 31, 2008**	
(in thousands)	**Gross Carrying amount**	**Accumulated amortization**	**Gross Carrying amount**	**Accumulated amortization**
Favorable propane contracts	**$ 519**	**$ 169**	$	$
Customer relationships FPU	**3,500**	**49**		
Customer list	**115**	**97**	115	90
Acquisition costs	**264**	**132**	264	125
	$ 4,398	**$ 447**	$ 379	$ 215

In the FPU merger, we acquired intangible assets related to propane customer relationships and favorable propane contracts, which are shown separately on the table above, and are amortized over a 12-year period and a period ranging from one to 14 months, respectively. Customer list and acquisition costs are related to our acquisitions in the late 1980 s and 1990 s, which are amortized over a 16-year period and a 40-year period, respectively.

Amortization expense of intangible assets for 2010 to 2014 is: $655,000 for 2010, $305,000 for 2011, $302,000 for 2012, $298,000 for 2013, and $298,000 for 2014.

Table of Contents

I. Income Taxes

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. FPU will be included in our 2009 consolidated federal return for the post-merger period. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. FPU will continue to file a separate state income tax return in Florida.

In September 2008, the IRS completed its examination of our 2005 and 2006 consolidated federal returns and issued its Examination Report. As a result of the examination, we reduced our income tax receivable by $27,000 for the tax liability associated with disallowed expense deductions included on the tax returns. We have amended our 2005 and 2006 federal and state corporate income tax returns to reflect the disallowed expense deductions. We are no longer subject to income tax examinations by the Internal Revenue Service for years before December 31, 2006. FPU filed a separate federal income tax return for the period prior to the merger and is not subject to income tax examinations by the IRS for years before December 31, 2005.

We generated net operating losses in 2008, for federal income tax purposes, which were generated primarily from increased book-to-tax timing differences authorized by the 2008 American Recovery and Reinvestment Act, which allowed bonus depreciation for certain assets. A federal tax net operating loss of $9,049,132 was carried forward to 2009 and fully offset taxable income for the year. As of December 31, 2009, we have a federal tax net operating loss of $202,000 which expires in 2027. As of December 31, 2009, we also had tax net operating losses from various states totaling $2.7 million, almost all of which expire in 2027. We have recorded a deferred tax asset of $305,000 related to these carry-forwards. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will all be utilized.

The tables below provide the following: (a) the components of income tax expense; (b) reconciliation between the statutory federal income tax rate and the effective income tax rate; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2009 and 2008.

For the Years Ended December 31,	**2009**	2008	2007
(in thousands)			
Current Income Tax Expense			
Federal	**$**	$ (2,551)	$ 5,512
State	**878**		1,223
Investment tax credit adjustments, net	**(69)**	(42)	(51)
Total current income tax expense (benefit)	**809**	(2,593)	6,684
Deferred Income Tax Expense (1)			
Property, plant and equipment	**7,187**	10,347	2,959
Deferred gas costs	**(786)**	781	(629)
Pensions and other employee benefits	**(612)**	(174)	(9)
Environmental expenditures	**7**	145	46
Net operating loss carryforwards	**4,043**		
Merger related costs	**967**		
Reserve for insurance deductibles	**518**	462	27
Other	**(1,215)**	(151)	(492)
Total deferred income tax expense (benefit)	**10,109**	11,410	1,902
Total Income Tax Expense	**$ 10,918**	$ 8,817	$ 8,586

For the Years Ended December 31,	**2009**	2008	2007
Reconciliation of Effective Income Tax Rates			
(in thousands)			
Continuing Operations			
Federal income tax expense (2)	**$ 9,171**	$ 7,863	$ 7,635
State income taxes, net of federal benefit	**1,490**	1,162	1,087
Merger related costs	**299**		
ESOP dividend deduction	**(213)**	(205)	(199)
Other	**171**	(3)	74
Total continuing operations	**10,918**	8,817	8,597
Discontinued operations			(11)
Total Income Tax Expense	**$ 10,918**	$ 8,817	$ 8,586
Effective income tax rate	**40.72%**	39.32%	39.41%

At December 31,	**2009**	**2008**
(in thousands)		
Deferred Income Taxes		
Deferred income tax liabilities:		

Property, plant and equipment	**$ 75,898**	$ 41,248
Environmental costs		395
Deferred gas costs	**689**	
Other	**3,162**	2,414
Total deferred income tax liabilities	**79,749**	44,057
Deferred income tax assets:		
Pension and other employee benefits	**6,406**	4,679
Environmental costs	**1,802**	
Self insurance	**1,318**	370
Storm reserve liability	**985**	
Deferred gas costs		364
Other	**3,813**	2,502
Total deferred income tax assets	**14,324**	7,915
Net Deferred Income Taxes Per Consolidated Balance Sheet	**$ 65,425**	$ 36,142

(1) Includes $985,000, $1,588,000 and $260,000 of deferred state income taxes for the years 2009, 2008 and 2007, respectively.

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

Table of Contents

J. Long-term Debt

Our outstanding long-term debt is as shown below.

(in thousands)	December 31, 2009	December 31, 2008
Secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$ 8,156**	$
10.03% bond, due May 1, 2018	**4,486**	
9.08% bond, due June 1, 2022	**7,950**	
6.85% bond, due October 1, 2031	**14,012**	
4.90% bond, due November 1, 2031	**13,222**	
Uncollateralized senior notes:		
6.91% note, due October 1, 2010	**909**	1,818
6.85% note, due January 1, 2012	**2,000**	3,000
7.83% note, due January 1, 2015	**10,000**	12,000
6.64% note, due October 31, 2017	**21,818**	24,545
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
Convertible debentures:		
8.25% due March 1, 2014	**1,520**	1,655
Promissory note	**40**	60
Total long-term debt	**134,113**	93,078
Less: current maturities	**(35,299)**	(6,656)
Total long-term debt, net of current maturities	**$ 98,814**	$ 86,422

Annual maturities of consolidated long-term debt are as follows: $36,765 for 2010; $9,156 for 2011; $8,136 for 2012; $8,136 for 2013; $12,656 for 2014 and $60,818 thereafter. The annual maturity for 2010 of $37,765 includes $28,700 of the secured first mortgage bonds redeemed prior to stated maturity in January 2010.

Secured First Mortgage Bonds

In October 2009, we became subject to the obligations of FPU s secured first mortgage bonds in connection with the merger. FPU s secured first mortgage bonds had a carrying value of $47.8 million ($49.3 million in outstanding principal balance). The first mortgage bonds are secured by a lien covering all of FPU s property. The 9.57 percent bond and 10.03 percent bond require annual sinking fund payments of $909,000 and $500,000, respectively.

In January 2010, we redeemed the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturity for $28.7 million, which represented the outstanding principal balance of those bonds. We used short-term borrowing to finance the redemption of these bonds. The difference between the carrying value of those bonds and the amount paid at redemption totaling $1.5 million was deferred as a regulatory asset.

Uncollateralized Senior Notes

On October 31, 2008, we issued $30 million of 5.93 percent uncollateralized senior notes to two institutional investors. The terms of the senior notes require a semi-annual principal repayment of $1.5 million in April and October of each year, commencing on April 30, 2014. The senior notes will mature on October 31, 2023. The proceeds of the sale of the Senior Notes were used to refinance capital expenditures and for general corporate purposes.

Table of Contents

Convertible Debentures

The convertible debentures may be converted, at the option of the holder, into shares of our common stock at a conversion price of $17.01 per share. During 2009 and 2008, debentures totaling $135,000 and $177,000, respectively, were converted to stock. The debentures are also redeemable for cash at the option of the holder, subject to an annual non-cumulative maximum limitation of $200,000. In 2009 and 2008, no debentures were redeemed for cash. At the Company s option, the debentures may be redeemed at stated amounts.

Debt Covenants

Indentures to our long-term debt contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40 percent of total capitalization, and the pro-forma fixed charge coverage ratio must be at least 1.2 times. In connection with the merger, the uncollateralized senior notes were amended to include an additional covenant requiring the Company to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth by October 2011. Failure to comply with those covenants could result in accelerated due dates and/or termination of the uncollateralized senior note agreements. As of December 31, 2009, we are in compliance with all of our debt covenants and with the redemption of FPU s 6.85 percent and 4.90 percent secured first mortgage bonds in January 2010, the additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth has been met.

Each of Chesapeake s uncollateralized senior notes contains a Restricted Payments covenant as defined in the note agreements. The most restrictive covenants of this type are included within the 7.83 percent senior notes, due January 1, 2015. The covenant provides that we cannot pay or declare any dividends or make any other Restricted Payments (such as dividends) in excess of the sum of $10.0 million, plus consolidated net income of the Company accrued on and after January 1, 2001. As of December 31, 2009, the cumulative consolidated net income base was $102.8 million, offset by Restricted Payments of $63.8 million, leaving $39.0 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 2031, which provided 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, 2001. As of December 31, 2009, FPU had the cumulative net income base of $32.7 million, offset by restricted payments of $22.1 million, leaving $10.6 million of cumulative net income of FPU free of restrictions based on this covenant. In January 2010, this series of first mortgage bonds were redeemed prior to their maturities. The second most restrictive covenant of this type is included in the series that is due in 2022, which provided 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. This covenant provides FPU with the cumulative net income base of $56.0 million, offset by restricted payments of $37.6 million, leaving $18.4 million of cumulative net income of FPU free of restrictions as of December 31, 2009.

K. Short-term Borrowing

At December 31, 2009 and 2008, the Company had $30.0 million and $33.0 million, respectively, of short-term borrowing outstanding under our bank credit facilities. The annual weighted average interest rates on its short-term borrowing were 1.28 percent and 2.79 percent for 2009 and 2008, respectively. We incurred commitment fees of $79,000 and $16,000 in 2009 and 2008, respectively.

In October 2009 in connection with the FPU merger, we became subject to $4.2 million in outstanding borrowings under FPU s revolving line of credit. All of the outstanding borrowings were repaid in full in November 2009 and FPU s revolving line of credit was terminated on November 23, 2009.

As of December 31, 2009, we had four unsecured bank lines of credit with two financial institutions, totaling $90.0 million, none of which requires compensating balances. The unsecured bank lines of credit were increased to $100.0 million in January 2010. These bank lines are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these short-term lines of credit. We maintain both committed and uncommitted credit facilities. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks.

Committed credit facilities

As of December 31, 2009 we had two committed revolving credit facilities totaling $55.0 million, which were subsequently increased to $60.0 million in January 2010. The first facility is an unsecured $30.0 million revolving line of credit that bears interest at the respective LIBOR rate, plus 1.25 percent per annum. At December 31, 2009, there was $7.5 million available under this credit facility.

The second facility is a $25.0 million committed revolving line of credit that bears interest at a base rate plus 1.25 percent, if requested and advanced on the same day, or LIBOR for the applicable period plus 1.25 percent if requested three days prior to the advance date. At December 31, 2009, there was $18.3 million available under this credit facility. In January 2010, the second facility was increased to a $30.0 million committed revolving line of credit with the same terms, resulting in total committed revolving credit facilities of $60.0 million.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. The Company is required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal year:

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

We are in compliance with all of our debt covenants.

Uncommitted credit facilities

As of December 31, 2009, we had two uncommitted lines of credit facilities totaling $35.0 million, which were subsequently increased to $40.0 million in January 2010. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks.

The first facility is an uncommitted $20.0 million line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. At December 31, 2009, the entire borrowing capacity of $20.0 million was available under this credit facility.

The second facility is a $15.0 million uncommitted line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. At December 31, 2009, there was $14.3 million available under this credit facility, which was reduced by $725,000 for a letter of credit issued to our primary insurance company. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies and expires on August 31, 2010. We do not anticipate that this letter of credit will be drawn upon by the counter-party and we expect that it will be renewed as necessary. In January 2010, the second facility was increased to a $20.0 million uncommitted line of credit with the same terms, resulting in total uncommitted revolving credit facilities of $40.0 million.

L. Lease Obligations

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases was $997,000, $880,000 and $736,000 for 2009, 2008 and 2007, respectively. Future minimum payments under our current lease agreements are $866,000, $771,000, $677,000, $502,000 and $364,000 for the years 2010 through 2014, respectively; and $2.0 million thereafter, with an aggregate total of $5.2 million.

M. Employee Benefit Plans

Retirement Plans

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

We measure the assets and obligations of the defined benefit pension plans and other postretirement benefits plans to determine the plans funded status as of the end of the year as an asset or a liability on our consolidated balance sheets. We recognize as a component of accumulated other comprehensive income/loss the changes in funded status that occurred during the year but that are not recognized as part of net periodic benefit costs, except for the portion related to FPU s regulated energy operations, which is deferred as a regulatory asset to be recovered in the future pursuant to a previous order by the Florida PSC. The measurement dates were December 31, 2009 and 2008.

The amounts in accumulated other comprehensive income/loss for our pension and postretirement benefits plans that are expected to be recognized as a component of net benefit cost in 2010 are set forth in the following table.

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ (5)	$	$ 19	$	$	$ 14
Net (gain) loss	$ (137)	$	$ 47	$ 71	$	$ (19)

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive income/loss as of December 31, 2009.

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ (15)	$	$ 102	$	$	$ 87
Net loss (gain)	2,672	(540)	673	1,351	(14)	4,142
Subtotal	2,657	(540)	775	1,351	(14)	4,229
Tax expense (benefit)	(1,065)	208	(311)	(542)	5	(1,705)
Accumulated other comprehensive (income) loss	$ 1,592	$ (332)	$ 464	$ 809	$ (9)	$ 2,524

Defined Benefit Pension Plans

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

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

Our funding policy provides that payments to the trustee of each plan shall be equal to the minimum funding requirements of the Employee Retirement Income Security Act of 1974. We were not required to make any funding payments to the Chesapeake Pension Plan in 2009 or to the FPU Pension Plan subsequent to the merger closing in October 2009.

Table of Contents

The following schedule summarizes the assets of the Chesapeake Pension Plan, by investment type, at December 31, 2009, 2008 and 2007 and the assets of the FPU Pension Plan, by investment type, at December 31, 2009:

	Chesapeake Pension Plan			FPU Pension Plan
At December 31,	**2009**	**2008**	**2007**	**2009**
Asset Category				
Equity securities	**66.22%**	48.70%	49.03%	**63.00%**
Debt securities	**33.76%**	51.24%	50.26%	**29.00%**
Other	**0.02%**	0.06%	0.71%	**8.00%**
Total	**100.00%**	100.00%	100.00%	**100.00%**

The asset listed as Other in the above table represents monies temporarily held in money market funds, which invest at least 80 percent of their total assets in:

- United States government obligations; and
- Repurchase agreements that are fully collateralized by such obligations.

All of the assets held by the Chesapeake Pension Plan and FPU Pension Plan are classified under Level 1 of the fair value hierarchy and are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.

The investment policy for the Chesapeake Pension Plan calls for an allocation of assets between equity and debt instruments, with equity being 60 percent and debt at 40 percent, but allowing for a variance of 20 percent in either direction. In addition, as changes are made to holdings, cash, money market funds or United States Treasury Bills may be held temporarily by the fund. Investments in the following are prohibited: options, guaranteed investment contracts, real estate, venture capital, private placements, futures, commodities, limited partnerships and Chesapeake stock; short selling and margin transactions are prohibited as well. Investment allocation decisions are made by the Employee Benefits committee. During 2004, Chesapeake modified its investment policy to allow the Employee Benefits Committee to reallocate investments to better match the expected life of the plan.

The investment policy for the FPU Pension Plan is designed to achieve a long-term rate of return, including investment income and appreciation, sufficient to meet the actuarial requirements of the plan. The plan s investment strategy is to achieve its return objectives by investing in a diversified portfolio of equity, fixed income and cash securities seeking a balance of growth and stability as well as an adequate level of liquidity for pension distributions as they fall due. Plan assets are constrained such that no more than 10 percent of the portfolio will be invested in any one issue. Investment allocation decisions for the FPU Pension Plan are made by the Pension Committee.

Table of Contents

The following schedule sets forth the funded status at December 31, 2009 and 2008:

At December 31,	Chesapeake Pension Plan 2009	Chesapeake Pension Plan 2008	FPU Pension Plan 2009
(in thousands)			
Change in benefit obligation:			
Benefit obligation beginning of year[1]	**$ 11,593**	$ 11,074	**$ 46,851**
Interest cost	**547**	594	**418**
Change in assumptions	**(188)**	268	
Actuarial loss	**(307)**	84	**(1,544)**
Benefits paid	**(518)**	(427)	**(305)**
Benefit obligation end of year	**11,127**	11,593	**45,420**
Change in plan assets:			
Fair value of plan assets beginning of year[1]	**6,689**	10,799	**35,037**
Actual return on plan assets	**1,278**	(3,683)	**1,695**
Benefits paid	**(518)**	(427)	**(305)**
Fair value of plan assets end of year	**7,449**	6,689	**36,427**
Reconciliation:			
Funded status	**(3,678)**	(4,904)	**(8,993)**
Accrued pension cost	**$ (3,678)**	$ (4,904)	**$ (8,993)**
Assumptions:			
Discount rate	**5.25%**	5.25%	**5.75%**
Expected return on plan assets	**6.00%**	6.00%	**7.00%**

(1) FPU Pension Plan s beginning balance reflects the benefit obligations as of the merger date of October 28, 2009.

Net periodic pension cost (benefit) for the plans for 2009, 2008, and 2007 include the components shown below:

For the Years Ended December 31,	Chesapeake Pension Plan 2009	Chesapeake Pension Plan 2008	Chesapeake Pension Plan 2007	FPU Pension Plan[1] 2009

(in thousands)				
Components of net periodic pension cost (benefit):				
Interest cost	**$ 547**	$ 594	$ 622	**$ 418**
Expected return on assets	**(362)**	(629)	(696)	**(396)**
Amortization of prior service cost	**(5)**	(5)	(5)	
Amortization of actuarial loss/gain	**237**			
Net periodic pension cost (benefit)	**$ 417**	$ (40)	$ (79)	**$ 22**
Assumptions:				
Discount rate	**5.25%**	5.50%	5.50%	**5.50%**
Expected return on plan assets	**6.00%**	6.00%	6.00%	**7.00%**

(1) FPU Pension Plan s net periodic pension cost includes only the cost from the merger closing (October 28, 2009) through December 31, 2009.

Table of Contents

Pension Supplemental Executive Retirement Plan

The Chesapeake SERP was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant s years of service and highest average compensation, prior to the freezing of the plan. The accumulated benefit obligation for the Chesapeake SERP, which is unfunded, was $2.5 million at both December 31, 2009 and 2008.

At December 31, *(In thousands)*	**2009**	2008
Change in benefit obligation:		
Benefit obligation beginning of year	**$ 2,520**	$ 2,326
Interest cost	**129**	125
Actuarial (gain) loss	**(55)**	39
Amendments		119
Benefits paid	**(89)**	(89)
Benefit obligation end of year	**2,505**	2,520
Change in plan assets:		
Fair value of plan assets beginning of year		
Employer contributions	**89**	89
Benefits paid	**(89)**	(89)
Fair value of plan assets end of year		
Reconciliation:		
Funded status	**(2,505)**	(2,520)
Accrued pension cost	**$ (2,505)**	$ (2,520)
Assumptions:		
Discount rate	**5.25%**	5.25%

Net periodic pension costs for the Chesapeake SERP for 2009, 2008, and 2007 include the components shown below:

For the Years Ended December 31, *(in thousands)*	**2009**	2008	2007
Components of net periodic pension cost:			
Interest cost	**$ 130**	$ 125	$ 123
Amortization of prior service cost	**18**		
Amortization of actuarial loss	**54**	45	52
Net periodic pension cost	**$ 202**	$ 170	$ 175
Assumptions:			
Discount rate	**5.25%**	5.50%	5.50%

Table of Contents

Other Postretirement Benefits Plans

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

	Chesapeake		FPU Medical
	Postretiment Plan		Plan
At December 31,	**2009**	**2008**	**2009**
(in thousands)			
Change in benefit obligation:			
Benefit obligation beginning of year[1]	**$ 2,179**	$ 1,756	**$ 2,457**
Service cost	**3**	3	**18**
Interest cost	**131**	114	**23**
Plan participants contributions	**90**	104	**6**
Actuarial (gain) loss	**378**	345	**(71)**
Benefits paid	**(196)**	(143)	**(16)**
Benefit obligation end of year	**2,585**	2,179	**2,417**
Change in plan assets:			
Fair value of plan assets beginning of year[1]			
Employer contributions[2]	**106**	39	**10**
Plan participants contributions	**90**	104	**6**
Benefits paid	**(196)**	(143)	**(16)**
Fair value of plan assets end of year			
Reconciliation:			
Funded status	**(2,585)**	(2,179)	**(2,417)**
Accrued pension cost	**$ (2,585)**	$ (2,179)	**$ (2,417)**
Assumptions:			
Discount rate	**5.25%**	5.25%	**5.75%**

(1) FPU Medical Plan s beginning balance reflects the benefit obligation as of the merger date of October 28, 2009.

(2) Chesapeake s Postretirement Plan does not

receive a Medicare Part-D subsidy. The FPU Medical Plan did not receive a significant subsidy for the post-merger period.

Net periodic postretirement costs for 2009, 2008, and 2007 include the following components:

For the Years Ended December 31,	Chesapeake Postretirement Plan 2009	Chesapeake Postretirement Plan 2008	Chesapeake Postretirement Plan 2007	FPU Medical Plan[(1)] 2009
(in thousands)				
Components of net periodic postretirement cost:				
Service cost	**$ 3**	$ 3	$ 6	**$ 18**
Interest cost	**131**	114	102	**23**
Amortization of:				
Actuarial loss	**76**	290	166	
Net periodic postretirement cost	**$ 210**	$ 407	$ 274	**$ 41**

(1) FPU Medical Plan s net periodic postretiment includes only the cost from the merger date (October 28, 2009) through December 31, 2009.

Table of Contents

Assumptions

The assumptions used for the discount rate to calculate the benefit obligation of all the plans were based on the interest rates of high-quality bonds in 2009, reflecting the expected life of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since the Chesapeake s plans and FPU s plans have a different expected life of the plan and investment policy, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different discount rate and expected return on plan asset assumptions were selected for Chesapeake s plans and FPU s plans. Since all of the pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation rate increases is not applicable.

The health care inflation rate for 2009 used to calculate the benefit obligation is 7.50 percent for medical and 8.50 percent for prescription drugs for the Chesapeake Postretirement Plan; and 10.50 percent for the FPU Medical Plan. A one-percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately $708,000 as of January 1, 2010, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2009 by approximately $30,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $594,000 as of January 1, 2010, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2009 by approximately $24,000.

Estimated Future Benefit Payments

In 2010, we expect to contribute $450,000 and $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $88,000 to the Chesapeake SERP. We also expect to contribute $115,000 and $144,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2010. The schedule below shows the estimated future benefit payments for each of our plans previously described:

(in thousands)	**Chesapeake Pension Plan**[(1)]	**FPU Pension Plan**[(1)]	**Chesapeake SERP**[(2)]	**Chesapeake Postretirement Plan**[(2)]	**FPU Medical Plan**[(2)(3)]
2010	$ 763	$ 2,176	$ 88	$ 115	$ 144
2011	429	2,308	797	113	158
2012	1,228	2,452	84	123	181
2013	484	2,617	82	127	176
2014	502	2,747	80	137	196
Years 2015 through 2019	3,649	14,914	634	781	1,215

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

(2) Benefit payments are expected to be paid out of the general funds of the Company.

(3) These amounts are shown net of estimated Medicare Part-D reimbursements of $10,000, $11,000, $11,000, $12,000 and $13,000 for the years 2010 to 2014 and $78,000 for years 2015 through 2019.

Table of Contents

Retirement Savings Plan

We sponsor two 401(k) retirement savings plans and one non-qualified supplemental employee retirement savings plan.

Chesapeake s 401(k) plan is offered to all eligible employees, except for those FPU employees, who have the opportunity to participate in FPU s 401(k) plan. We make matching contributions on up to six percent of each Chesapeake employee s eligible pre-tax compensation for the year, except for the employees of our advanced information services subsidiary, as further explained below. The match is between 100 percent and 200 percent of the employee s contribution (up to six percent), based on the employee s age and years of service. The first 100 percent is matched with Chesapeake common stock; the remaining match is invested in Chesapeake s 401(k) Plan according to each employee s election options. Employees are automatically enrolled at a two percent contribution, with the option of opting out, and are eligible for the company match after three months of continuing service, with vesting of 20 percent per year.

Effective July 1, 2006, our contribution made on behalf of the advanced information services subsidiary employees, is a 50 percent matching contribution, on up to six percent of each employee s annual compensation contributed to the plan. The matching contribution is funded in Chesapeake common stock. The plan was also amended at the same time to enable it to receive discretionary profit-sharing contributions in the form of employee pre-tax deferrals. The extent to which the advanced information services subsidiary has any dollars available for profit-sharing is dependent upon the extent to which the segment s actual earnings exceed budgeted earnings. Any profit-sharing dollars made available to employees can be deferred into the plan and/or paid out in the form of a bonus.

Effective January 1, 1999, we began offering a non-qualified supplemental employee retirement savings plan (401(k) SERP) to our executives over a specific income threshold. Participants receive a cash-only matching contribution percentage equivalent to their 401(k) match level. All contributions and matched funds can be invested among the mutual funds available for investment. These same funds are available for investment of employee contributions within Chesapeake s 401(k) plan. All obligations arising under the 401(k) SERP are payable from our general assets, although we have established a Rabbi Trust for the 401(k) SERP. As discussed further in Note G Investments, to the Consolidated Financial Statements, the assets held in the Rabbi Trust included a fair value of $1.9 million and $1.4 million at December 31, 2009 and 2008, respectively, related to the 401(k) SERP. The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

We continue to maintain a separate 401(k) retirement savings plan for FPU. FPU s 401(k) plan provides a matching contribution of 50 percent of an employee s pre-tax contributions, up to six percent of the employee s salary, for a maximum company contribution of up to three percent. Beginning in 2007, for non-union employees the plan provides a company match of 100 percent for the first two percent of an employee s contribution, and a match of 50 percent for the next four percent of an employee s contribution, for a total company match of up to four percent. Employees are automatically enrolled at three percent contribution, with the option of opting out, and are eligible for the company match after six months of continuous service, with vesting of 100 percent after three years of continuous service.

Our contributions to the 401(k) plans totaled $1.6 million (including a $10,000 contribution made to FPU s 401(k) plan after the merger), $1.6 million, and $1.5 million for the years ended December 31, 2009, 2008, and 2007, respectively. As of December 31, 2009, there are 10,281 shares reserved to fund future contributions to Chesapeake s 401(k) plan.

Deferred Compensation Plan

On December 7, 2006, the Board of Directors approved the Chesapeake Utilities Corporation Deferred Compensation Plan (Deferred Compensation Plan), as amended, effective January 1, 2007. The Deferred Compensation Plan is a non-qualified, deferred compensation arrangement under which certain executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors retainer and fees. At December 31, 2009, the Deferred Compensation Plan consisted solely of shares of common stock related to the deferral of executive performance shares and directors stock retainers.

Table of Contents

Participants in the Deferred Compensation Plan are able to elect the payment of benefits to begin on a specified future date after the election is made in the form of a lump sum or annual installments. Deferrals of executive cash bonuses and directors cash retainers and fees are paid in cash. All deferrals of executive performance shares and directors stock retainers are paid in shares of our common stock, except that cash is be paid in lieu of fractional shares.

We established a Rabbi Trust in connection with the Deferred Compensation Plan. The value of our stock held in the Rabbi Trust is classified within the stockholders equity section of the Balance Sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled $739,000 and $1.5 million at December 31, 2009 and 2008, respectively.

N. Share-Based Compensation Plans

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

The table below presents the amounts included in net income related to share-based compensation expense, for the restricted stock awards issued under the DSCP and the PIP for the years ended December 31, 2009, 2008 and 2007.

For the Years Ended December 31,	**2009**	**2008**	**2007**
(in thousands)			
Directors Stock Compensation Plan	**$ 191**	$ 180	$ 181
Performance Incentive Plan	**1,115**	640	809
Total compensation expense	**1,306**	820	990
Less: tax benefit	**523**	327	386
Share-Based Compensation amounts included in net income	**$ 783**	$ 493	$ 604

Stock Options

We did not have any stock options outstanding at December 31, 2009, 2008 or 2007, nor were any stock options issued during 2009, 2008 and 2007.

Directors Stock Compensation Plan

Under the DSCP, each of our non-employee directors received in 2009 an annual retainer of 650 shares of common stock and additional shares of common stock for serving as a committee chairperson. For 2009, the Corporate Governance and Compensation Committee Chairperson each received 150 additional shares of common stock and the Audit Committee Chairperson received 250 additional shares of common stock. Shares granted under the DSCP are issued in advance of the directors service period; therefore, these shares are fully vested as of the grant date. We record a prepaid expense as of the date of the grant equal to the fair value of the shares issued and amortize the expense equally over a service period of one year.

Table of Contents

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

	Number of Shares	Weighted Average Grant Date Fair Value	
Outstanding December 31, 2007			
Granted	6,161	$	29.43
Vested	6,161	$	29.43
Forfeited			
Outstanding December 31, 2008			
Granted[(1)]	7,174	$	29.83
Vested	7,174	$	29.83
Forfeited			
Outstanding December 31, 2009			

(1) On October 28, 2009, the Company added two new members to its Board of Directors; each new board member was awarded 337 shares of common stock.

We recorded compensation expense of $191,000, $180,000 and $181,000 related to DSCP awards for the years ended December 31, 2009, 2008 and 2007, respectively.

The weighted-average grant-date fair value of DSCP awards granted during 2009 and 2008 was $29.83 and $29.43, per share, respectively. The intrinsic values of the DSCP awards are equal to the fair market value of these awards on the date of grant. At December 31, 2009, there was $64,000 of unrecognized compensation expense related to DSCP awards that is expected to be recognized over the first four months of 2010.

As of December 31, 2009, there were 44,115 shares reserved for issuance under the terms of the Company s DSCP.

Performance Incentive Plan (PIP)

Our Compensation Committee is authorized to grant key employees of the Company the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals. These awards are subject to certain post-vesting transfer restrictions.

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

The shares granted under the PIP in 2007 are fully vested, and the fair value of each share is equal to the market price of our common stock on the date of the grant. The shares granted under the 2008 and 2009 long-term plans have not vested as of December 31, 2009, and the fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

Table of Contents

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

		Number of Shares		Weighted Average Fair Value
Outstanding	December 31, 2007	33,760	$	29.90
Granted		94,200	$	27.84
Vested		31,094	$	29.90
Fortfeited				
Expired		2,666	$	29.90
Outstanding	December 31, 2008	94,200	$	27.84
Granted		28,875	$	29.19
Vested				
Fortfeited				
Expired				
Outstanding	December 31, 2009	123,075	$	28.15

In 2009, no shares under the PIP vested. In 2008, we withheld shares with value equivalent to the employees minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives receiving the net shares. The total number of shares withheld (12,511) for 2008 was based on the value of the PIP shares on their vesting date, determined by the average of the high and low of our stock price. No payments for the employee s tax obligations were made to taxing authorities in 2009 as no shares vested during this period. Total payments for the employees tax obligations to the taxing authorities were approximately $383,000 in 2008.

We recorded compensation expense of $1.1 million, $640,000 and $809,000 related to the PIP for the years ended December 31, 2009, 2008, and 2007, respectively.

The weighted-average grant-date fair value of PIP awards granted during 2009, 2008 and 2007 was $29.19, $27.84 and $29.90, per share respectively. The intrinsic value of the PIP awards was $2.1 million and $1.1 million for 2009 and 2008, respectively. The intrinsic value of the 2007 awards was equal to the fair market value of these awards on the date of grant.

As of December 31, 2009, there were 371,293 shares reserved for issuance under the terms of our PIP.

O. Environmental Commitments and Contingencies

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

We have participated in the investigation, assessment or remediation and have certain exposures at six former MGP sites. Those sites are located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the MDE regarding a seventh former MGP site located in Cambridge, Maryland. The Key West, Pensacola, Sanford and West Palm Beach sites are related to FPU, for which we assumed in the merger any existing and future contingencies.

Table of Contents

As of December 31, 2009, we had recorded $531,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of the future costs associated with those sites. We had recorded approximately $1.7 million in regulatory and other assets for future recovery of environmental costs from Chesapeake s customers through its approved rates. As of December 31, 2009, we had recorded approximately $12.3 million in environmental liabilities related to FPU s MGP sites in Florida, primarily from the West Palm Beach site, which represents our estimate of the future costs associated with those sites. FPU is approved to recover its environmental costs up to $14.0 million from insurance and customers through rates. Approximately $5.7 million of FPU s expected environmental costs has been recovered from insurance and customers through rates as of December 31, 2009. We also had recorded approximately $6.6 million in regulatory assets for future recovery of environmental costs from FPU s customers.

The following discussion provides details on each site.

Salisbury, Maryland

We have completed remediation of this site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an Air Sparging and Soil-Vapor Extraction (AS/SVE) system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to decommission permanently the AS/SVE system and to discontinue all on-site and off-site well monitoring, except for one well which is being maintained for continued product monitoring and recovery. We have requested and are awaiting a No Further Action determination from the MDE.

Through December 31, 2009, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies at this site and do not expect to incur any additional costs. We have recovered approximately $2.1 million through insurance proceeds or in rates and have $783,000 of the clean-up costs not yet recovered.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a Consent Order entered into with the FDEP, we are obligated to assess and remediate environmental impacts to the site resulting from the former operation of a MGP on the site. In 2001, FDEP approved a Remedial Action Plan (RAP) requiring construction and operation of a bio-sparge/soil vapor extraction (BS/SVE) treatment system to address soil and groundwater impacts at a portion of the site. The BS/SVE treatment system has been in operation since October 2002. The Fourteenth Semi-Annual RAP Implementation Status Report was submitted to FDEP in January 2010. The groundwater sampling results through October 2009 show, in general, a reduction in contaminant concentrations over prior years, although the rate of reduction has declined recently. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. At present, we predict that remedial action objectives may be met for the area being treated by the BS/SVE treatment system in approximately three years.

The BS/SVE treatment system does not address impacted soils in the southwest corner of the site. We are currently completing additional soil and groundwater sampling at this location for the purpose of designing a remedy for this portion of the site. Following the completion of this field work, we will submit a soil excavation plan to FDEP for its review and approval.

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

Table of Contents

Through December 31, 2009, we have incurred and paid approximately $1.4 million for this site and estimates an additional cost of $531,000 in the future, which has been accrued. We have recovered through rates $1.1 million of the costs and continue to expect that the remaining $885,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

Key West, Florida

FPU formerly owned and operated an MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. FDEP has not required any further work at the site as of this time. Our portion of the consulting/remediation costs which may be incurred at this site is projected to be $93,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP was also owned by Gulf Power Corporation (Gulf Power). Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action (NFA) determination for the site, which must include a requirement for institutional/engineering controls. The group, consisting of Gulf Power, City of Pensacola, FDOT and FPU, is proceeding with preparation of the necessary documentation to submit the NFA justification. Consulting/remediation costs are projected to be $14,000.

Sanford, Florida

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

In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by EPA for the site. FPU s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13 million, or $650,000. As of December 31, 2009, FPU paid $300,000 to the Sanford Group escrow account for its share of funding requirements, and in January 2010, the Company paid the remaining $350,000 of this funding requirement.

The Sanford Group, EPA and the U.S. Department of Justice entered into a Consent Decree in March 2008, which was entered by the federal court in Orlando on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have/will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third party claims.

As of December 31, 2009, FPU s remaining share of remediation expenses, including attorney s fees and costs, is estimated to be $401,000, of which $350,000 was paid to the Sanford Group escrow account in January 2010. However, the Company is unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU s asserted defense to liability for costs exceeding $13 million to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has committed to fund under the Third Participation Agreement.

Table of Contents

West Palm Beach, Florida

We are currently evaluating remedial options to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida upon which FPU previously operated an MGP. Pursuant to a Consent Order between FPU and the FDEP, effective April 8, 1991, FPU completed the delineation of soil and groundwater impacts at the site. On June 30, 2008, FPU transmitted a revised feasibility study, evaluating appropriate remedies for the site, to the FDEP. On April 30, 2009, FDEP issued a remedial action order, which it subsequently withdrew. In response to the order and as a condition to its withdrawal, FPU committed to perform additional field work in 2009 and complete an additional engineering evaluation of certain remedial alternatives. The scope of this work has increased in response to FDEP s demands for additional information.

The feasibility study evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. Based on the likely acceptability of proven remedial technologies described in the feasibility study and implemented at similar sites, management believes that consulting/remediation costs to address the impacts now characterized at the West Palm Beach site will range from \$7.4 million to \$18.9 million. This range of costs covers such remedies as in situ solidification for deeper soil impacts, excavation of superficial soil impacts, installation of a barrier wall with a permeable biotreatment zone, monitored natural attenuation of dissolved impacts in groundwater, or some combination of these remedies.

Negotiations between FPU and the FDEP on a final remedy for the site continue. Prior to the conclusion of those negotiations, we are unable to determine, to a reasonable degree of certainty, the full extent or cost of remedial action that may be required. As of December 31, 2009, and subject to the limitations described above, we estimate the remediation expenses, including attorneys fees and costs, will range from approximately \$7.8 million to \$19.4 million for this site.

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

Other

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

P. Other Commitments and Contingencies

Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; ESNG, our natural gas transmission operation, is subject to regulation by the FERC. Chesapeake s Florida natural gas distribution division and FPU s natural gas and electric operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware. On September 2, 2008, our Delaware division filed with the Delaware Public Service Commission (Delaware PSC) its annual Gas Sales Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2008. On September 16, 2008, the Delaware PSC authorized the Delaware division to implement the GSR charges on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware division was required by its natural gas tariff to file a revised application if its projected over-collection of gas costs for the determination period of November 2007 through October 2008 exceeded four and one-half percent (4.5 percent) of total firm gas costs. As a result of a significant decrease in the cost of natural gas, the Delaware division, on January 8, 2009, filed with the Delaware PSC a supplemental GSR Application, seeking approval to change its GSR, effective February 1, 2009. On January 29, 2009, the Delaware PSC authorized the Delaware division to implement the revised GSR charges on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, the Delaware PSC, our Delaware division and the Division of the Public Advocate. Pursuant to the settlement agreement, our Delaware division, commencing in November 2009, adjusted the margin-sharing mechanism related to its Asset Management Agreement to reduce its proportionate share of such margin. We anticipate a net margin reduction of approximately $8,000 per year from this change.

As part of the settlement, the parties also agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, PESCO. On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates, and the amount actually received by the Delaware division for capacity released to PESCO. We have estimated that, exclusive of any interest, the amount that would have to be refunded if the Hearing Examiner s recommendation is approved without modification by the Delaware PSC is approximately $700,000 as of December 31, 2009. The Hearing Examiner has also recommended that the Delaware PSC require us to adhere to asymmetrical pricing principles regarding all future capacity releases by the Delaware division to PESCO, if any. Accordingly, if the Hearing Examiner s recommendation is approved without modification by the Delaware PSC and if the Delaware division temporarily released any capacity to PESCO below the maximum tariff rates, the Delaware division would have to credit to its firm service customers amounts equal to the maximum tariff rates that the Delaware division pays for long-term capacity, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. We disagree with the Hearing Examiner s recommendations and filed exceptions to those recommendations on February 5, 2010. The hearing on our exceptions took place before the Delaware PSC on February 18, 2010, but no ruling was made by the Delaware PSC. We anticipate a ruling by the Delaware PSC in March 2010. We believe that the Delaware division has been following proper procedures for capacity release established by the FERC and based on a previous settlement approved by the Delaware PSC and therefore, we have not recorded a liability for this contingency.

On December 2, 2008, our Delaware division filed two applications with the Delaware PSC, requesting approval for a Town of Milton Franchise Fee Rider and a City of Seaford Franchise Fee Rider. These Riders allow the division to recover from natural gas customers located within the Town of Milford or the City of Seaford a proportionate share of the franchise fees paid by the division. The Delaware PSC granted approval of both Franchise Fee Riders on January 29, 2009.

On September 4, 2009, our Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2009. On October 6, 2009, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2009, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware division anticipates a final decision by the Delaware PSC on this application in the second quarter of 2010.

On December 17, 2009, our Delaware division filed an application with the Delaware PSC, requesting approval for an Individual Contract Rate for service to be rendered to a potential large industrial customer. On or about October 2, 2009, the Delaware division entered into a negotiated gas service agreement with a potential customer pursuant to which the Delaware division would provide transportation, balancing, and gas delivery service to the customer s facilities in Delaware. The Delaware division s obligations under the agreement are subject to several conditions, including the condition that the agreement be approved by the Delaware PSC. The Delaware division and the potential customer consider the specific terms and conditions of the agreement to be confidential and proprietary. The Delaware division anticipates a final decision by the Delaware PSC on this application in the first quarter of 2010.

Table of Contents

Maryland. On December 16, 2008, the Maryland Public Service Commission (Maryland PSC) held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by our Maryland division during the 12 months ended September 30, 2008. No issues were raised at the hearing, and on December 19, 2008, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings, which became a final Order of the Maryland PSC on January 21, 2009.

On April 24, 2009, the Maryland PSC issued an Order defining utilities payment plan parameters and termination procedures that would increase the likelihood that customers could pay their past due amounts to avoid termination of natural gas service. This Order requires our Maryland division to: (a) provide customers in writing, prior to issuing a termination notice, certain details about their past due balance and information about available payment plans, and (b) continue to offer flexible and tailored payment plans. The Maryland division has implemented procedures to comply with this Order.

On December 1, 2009, the Maryland PSC held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Company s Maryland division during the 12 months ended September 30, 2009. No issues were raised at the hearing, and on December 9, 2009, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. On January 8, 2010, the Maryland PSC issued an Order affirming the Hearing Examiner s decisions in the matter, but made certain clarifications and corrections to the text of the proposed Order issued by the Hearing Examiner.

Florida. On July 14, 2009, Chesapeake s Florida division filed with the Florida PSC its petition for a rate increase and request for interim rate relief. In the application, the Florida division sought approval of: (a) an interim rate increase of $417,555; (b) a permanent rate increase of $2,965,398, which represented an average base rate increase, excluding fuel costs, of approximately 25 percent for the Florida division s customers; (c) implementation or modification of certain surcharge mechanisms; (d) restructuring of certain rate classifications; and (e) deferral of certain costs and the purchase premium associated with the pending merger with FPU. On August 18, 2009, the Florida PSC approved the full amount of the Florida division s interim rate request, subject to refund, applicable to all meters read on or after September 1, 2009. On December 15, 2009, the Florida PSC: (a) approved a $2,536,307 permanent rate increase (86 percent of the requested amount) applicable to all meters read on or after January 14, 2010; (b) determined that there is no refund required of the interim rate increase; and (c) ordered Chesapeake s Florida division and FPU s natural gas distribution operations to submit data no later than April 29, 2011 (which is 18 months after the merger) that details all known benefits, synergies and cost savings that have resulted from the merger).

Also on December 15, 2009, the Florida PSC approved the settlement agreement for a final natural gas rate increase of $7,969,000 for FPU s natural gas distribution operation, which represents approximately 80 percent of the requested base rate increase of $9,917,690 filed by FPU in the fourth quarter of 2008. The Florida PSC had approved an annual interim rate increase of $984,054 on February 10, 2009 and approved the permanent rate increase of $8,496,230 in an order issued on May 5, 2009, with the new rates to be effective beginning on June 4, 2009. On June 17, 2009, however, the Office of Public Counsel entered a protest to the Florida PSC s order and its final natural gas rate increase ruling, which protest required a full hearing to be held within eight months. Subsequent negotiations led to the settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved on December 15, 2009. The rates authorized pursuant to the order approving the settlement agreement became effective on January 14, 2010 and in February 2010, FPU refunded to its natural gas customers approximately $290,000 representing revenues in excess of the amount provided by the settlement agreement that had been billed to customers from June 2009 through January 14, 2010.

Table of Contents

On September 1, 2009, FPU s electric distribution operation filed its annual Fuel and Purchased Power Recovery Clause, which seeks final approval of its 2008 fuel-related revenues and expenses and new fuel rates for 2010. On January 4, 2010, the Florida PSC approved the proposed 2010 fuel rates, effective on or after January 1, 2010.

On September 11, 2009, Chesapeake s Florida division and FPU s natural gas distribution operation separately filed their respective annual Energy Conservation Cost Recovery Clause, seeking final approval of their 2008 conservation-related revenues and expenses and new conservation surcharge rates for 2010. On November 2, 2009, the Florida PSC approved the proposed 2010 conservation surcharge rates for both the Florida division and FPU, effective for meters read on or after January 1, 2010.

Also on September 11, 2009, FPU s natural gas distribution operation filed its annual Purchased Gas Adjustment Clause, seeking final approval of its 2008 purchased gas-related revenues and expenses and new purchased gas adjustment cap rate for 2010. On November 4, 2009, the Florida PSC approved the proposed 2010 purchased gas adjustment cap, effective on or after January 1, 2010.

The City of Marianna Commissioners voted on July 7, 2009 to enter into a new ten year franchise agreement with FPU effective February 1, 2010. The agreement provides that new interruptible and time of use rates shall become available for certain customers prior to February 2011 or, at the option of the City, the franchise agreement could be voided nine months after that date. The new franchise agreement contains a provision for the City to purchase the Marianna portion of FPU s electric system. Should FPU fail to make available the new rates, and if the franchise agreement is then voided by the City and the City elects to purchase the Marianna portion of the distribution system, it would require the city to pay FPU severance/reintegration costs, the fair market value for the system, and an initial investment in the infrastructure to operate this limited facility. If the City purchased the electric system, FPU would have a gain in the year of the disposition; but, ongoing financial results would be negatively impacted from the loss of the Marianna area from its electric operations.

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

System Expansion 2006 2008. In accordance with the requirements in the FERC s Order Issuing Certificate for the 2006 2008 System Expansion, ESNG had until June 13, 2009, to construct the remaining facilities that were authorized in the project filing. On February 3, 2009, ESNG requested authorization to modify the previously required completion date and to commence construction of the facilities, which provide for the remaining 6,957 Mcfs of additional firm service capacity previously approved by the FERC. On March 13, 2009, the FERC granted the requested authorization. On October 30, 2009, ESNG received approval from the FERC to commence services in November 2009 on this remaining portion of the 2006-2008 system expansion, which will permit ESNG to realize an additional annualized gross margin of approximately $1.0 million.

Energylink Expansion Project (E3 Project). In 2006, ESNG proposed to develop, construct and operate approximately 75 miles of new pipeline facilities from the existing Cove Point Liquefied Natural Gas terminal in Calvert County, Maryland, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, Maryland, to points on the Delmarva Peninsula, where such facilities would interconnect with ESNG s existing facilities in Sussex County, Delaware.

In April 2009, ESNG terminated the E3 Project and initiated billing to recover specified project costs in accordance with the terms of the precedent agreements executed with the two participating customers, one of which is Chesapeake, through its Delaware and Maryland divisions. These billings will reimburse ESNG for the $3.17 million of costs incurred in connection with the E3 Project, including the cost of capital, over a period of 20 years.

Prior Notice Request. On November 25, 2009 ESNG filed a prior notice request, proposing to construct, own and operate new mainline facilities to deliver additional firm entitlements of 1,594 Mcfs per day of natural gas to Chesapeake s Delaware division. The FERC published notice of this filing on December 7, 2009 and with no protest during the 60-day period following the notice, the proposed activity became effective on February 6, 2010. ESNG expects to realize an annualized margin of approximately $343,000 upon its completion of the facilities and implementation of the new service.

FERC Order Nos. 712 and 712-A. In June and November 2008, the FERC issued Order Nos. 712 and 712-A, which revised its regulations regarding interstate natural gas pipeline capacity release programs. The Orders: (a) remove the rate ceiling on capacity release transactions of one year or less; (b) facilitate the use of asset management arrangements for certain capacity releases; and (c) facilitate state-approved retail open access programs. The Orders required interstate gas pipeline companies to remove any inconsistent tariff provisions within 180 days of the effective date of the rule. On February 2, 2009, ESNG submitted revised tariff sheets to comply with the requirements set forth in the Orders. Amended tariff sheets were subsequently filed on February 26, 2009, which made minor clarifications and corrections. On March 27, 2009, ESNG received FERC approval of these amended tariff sheets with an effective date of March 1, 2009. Implementation of these amended tariff provisions will have no financial impact on ESNG.

ESNG also had developments in the following FERC matters:

On April 30, 2009, ESNG submitted its annual Interruptible Revenue Sharing Report to the FERC. ESNG reported in this filing that it refunded to its eligible firm customers a total of $245,500, inclusive of interest, in the second quarter of 2009.

On May 29, 2009, ESNG submitted its annual Fuel Retention Percentage (FRP) and Cash-Out Surcharge filings to the FERC. In these filings, ESNG proposed to implement an FRP rate of 0.12 percent and a zero rate for its Cash-Out Surcharge. ESNG also proposed to refund a total of $294,540, inclusive of interest, to its eligible customers in the second quarter of 2009 by netting its over-recovered fuel cost against its under-recovered cash-out cost. The FERC approved these proposals, and ESNG refunded $294,540 to customers in July 2009.

On June 1, 2009, ESNG submitted revised tariff sheets to comply with FERC Order No. 587-T, which adopted Version 1.8 of the North American Energy Standards Board Wholesale Gas Quadrant s standards. FERC found this rule necessary to increase the efficiency of the pipeline grid, make pipelines electronic communications more secure and provide consistency with the mandate that agencies provide for electronic disclosure of information. ESNG s revised tariff sheets were approved on August 11, 2009, by the FERC, which will have no financial impact on ESNG.

On August 21, 2009, ESNG filed revised tariff sheets to reflect an increase in the Annual Charge Adjustment (ACA) surcharge from $0.0017 per Dt to $0.0019 per Dt. The ACA surcharge is designed to recover applicable program costs incurred by the FERC. The tariff sheets were accepted as proposed and were made effective on October 1, 2009. As the ACA is passed-through to ESNG s customers, there will be no financial impact on ESNG.

On December 11, 2009, ESNG filed revised tariff sheets to reflect a new section 42, Consolidation of Service Agreements, to the General Terms and Conditions of its FERC Gas Tariff. Section 42 states that shippers may, at their option and subject to certain conditions, consolidate multiple service agreements under a rate schedule into a new service agreement(s) under that rate schedule. The tariff sheets were accepted by the FERC on January 7, 2010, as proposed and were made effective January 15, 2010. As this new section allows for consolidation of existing service agreements only, there will be no financial impact on ESNG.

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase gas and electricity from various suppliers. The contracts have various expiration dates. In March 2009, we renewed our contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2012.

PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements before the existing agreements expire in May 2010.

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA requires FPU to comply with the following ratios based on the result of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 and (b) fixed charge coverage greater than 1.5. If either of the ratios is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s agreement with Gulf requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operation interest coverage (minimum of 2 to 1) and (b) total debt to total capital (maximum of 0.65 to 1). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of action taken or proposed to be taken to be compliant. Failure to comply with the ratios specified in the Gulf agreement could result in FPU providing an irrevocable letter of credit. FPU was in compliance with these requirements as of December 31, 2009.

Corporate Guarantees

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for the Company s propane wholesale marketing subsidiary and its natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2009 was $22.7 million, with the guarantees expiring on various dates in 2010.

In addition to the corporate guarantees, we have issued a letter of credit to the Company s primary insurance company for $725,000, which expires on August 31, 2010. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of December 31, 2009. We do not anticipate that this letter of credit will be drawn upon by the counterparty and we expect that it will be renewed to the extent necessary in the future.

Other

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

Table of Contents

Q. Quarterly Financial Data (Unaudited)
In the opinion of the Company, the quarterly financial information shown below includes all adjustments necessary for a fair presentation of the operations for such periods. Due to the seasonal nature of the Company s business, there are substantial variations in operations reported on a quarterly basis.

For the Quarters Ended	**March 31**	**June 30**	**September 30**	**December 31**
(in thousands, except per share amounts)				
2009 [1]				
Operating Revenue	**$ 104,479**	**$ 40,834**	**$ 31,758**	**$ 91,715**
Operating Income	**$ 15,966**	**$ 2,856**	**$ 2,257**	**$ 12,658**
Net Income (Loss)	**$ 8,593**	**$ 806**	**$ 308**	**$ 6,190**
Earnings (Loss) per share:				
Basic	**$ 1.26**	**$ 0.12**	**$ 0.04**	**$ 0.71**
Diluted	**$ 1.24**	**$ 0.12**	**$ 0.04**	**$ 0.71**
2008				
Operating Revenue	$ 100,274	$ 69,057	$ 49,698	$ 72,415
Operating Income	$ 14,041	$ 4,329	$ 1,170	$ 8,938
Net Income (Loss)	$ 7,574	$ 1,819	$ (198)	$ 4,412
Earnings (Loss) per share:				
Basic	$ 1.11	$ 0.27	$ (0.03)	$ 0.65
Diluted	$ 1.10	$ 0.27	$ (0.03)	$ 0.64

(1) The quarter ended December 31, 2009 includes the results from the merger with FPU, which became effective on October 28, 2009.

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

Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure.
None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures
The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated the Company s disclosure controls and procedures (as such term is defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of

December 31, 2009. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of December 31, 2009.

Changes in Internal Controls

Other than the Chesapeake and FPU merger discussed below, there has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2009, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. Chesapeake is in the process of integrating FPU s operations and has not included FPU s activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions for additional information relating to the FPU merger. FPU s operations constituted approximately 30 percent of total assets (excluding goodwill and other intangible assets) as of December 31, 2009, and 10 percent of operating revenues for the year then ended. FPU s operations will be included in Chesapeake s assessment as of December 31, 2010.

Table of Contents

CEO and CFO Certifications

The Company s Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2009. In addition, on June 1, 2009 the Company s Chief Executive Officer certified to the NYSE that he was not aware of any violation by the Company of the NYSE corporate governance listing standards.

Management s Report on Internal Control Over Financial Reporting

The report of management required under this Item 9A is contained in Item 8 of this Form 10-K under the caption Management s Report on Internal Control over Financial Reporting.

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

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

We have audited Chesapeake Utilities Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Chesapeake Utilities Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

As indicated in the accompanying Management s Report on Internal Control Over Financial Reporting, the Company completed a merger with Florida Public Utilities Company (FPU) in 2009. As permitted by the Securities and Exchange Commission, management excluded the non-integrated FPU operations from its assessment of internal control over financial reporting as of December 31, 2009. Non-integrated FPU operations constituted approximately 30 percent of total assets (excluding goodwill and other intangible assets) as of December 31, 2009, and 10 percent of operating revenue for the year then ended. Our audit of internal control over financial reporting of Chesapeake Utilities Corporation as of December 31, 2009, did not include an evaluation of the internal controls over financial reporting of the non-integrated operations of FPU.

In our opinion, Chesapeake Utilities Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Chesapeake Utilities Corporation as of December 31, 2009 and 2008, and the related consolidated statements of income, stockholders equity and cash flows of Chesapeake Utilities Corporation, and our report dated March 8, 2010 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2010

Table of Contents

Item 9B. Other Information.

None

Part III

Item 10. Directors, Executive Officers of the Registrant and Corporate Governanace.

The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned Election of Directors (Proposal 1), Information Concerning Nominees and Continuing Directors, Corporate Governance, Committees of the Board Audit Committee and Section 16(a) Beneficial Ownership Reporting Compliance, to be filed not later than March 31, 2010, in connection with the Company s Annual Meeting to be held on or about May 5, 2010.

The information required by this Item with respect to executive officers is, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, set forth in this report following Item 4, as Item 4A, under the caption Executive Officers of the Company.

The Company has adopted a Code of Ethics for Financial Officers, which applies to its principal executive officer, president, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The information set forth under Item 1 hereof concerning the Code of Ethics for Financial Officers is filed herewith.

Item 11. Executive Compensation.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned Director Compensation, Executive Compensation and Compensation Discussion and Analysis in the Proxy Statement to be filed not later than March 31, 2010, in connection with the Company s Annual Meeting to be held on or about May 5, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned Security Ownership of Certain Beneficial Owners and Management to be filed not later than March 31, 2010, in connection with the Company s Annual Meeting to be held on or about May 5, 2010.

Table of Contents

The following table sets forth information, as of December 31, 2009, with respect to compensation plans of Chesapeake and its subsidiaries, under which shares of Chesapeake common stock are authorized for issuance:

	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			439,258(1)
Equity compensation plans not approved by security holders			
Total			439,258

(1) Includes 371,293 shares under the 2005 Performance Incentive Plan, 44,115 shares available under the 2005 Directors Stock Compensation Plan, and 23,850 shares available under the 2005 Employee Stock Awards Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned, Corporate Governance, to be filed no later than March 31, 2010 in connection with the Company s Annual Meeting to be held on or about May 5, 2010.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned Fees and Services of Independent Registered Public Accounting Firm, to be filed not later than March 31, 2010, in connection with the Company s Annual Meeting to be held on or about May 5, 2010.

Table of Contents

Part IV

Item 15. Exhibits, Financial Statement Schedules.

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

1. **Financial Statements:**

   Report of Independent Registered Public Accounting Firm;

   Consolidated Statements of Income for each of the three years ended December 31, 2009, 2008, and 2007;

   Consolidated Balance Sheets at December 31, 2009 and December 31, 2008;

   Consolidated Statements of Cash Flows for each of the three years ended December 31, 2009, 2008, and 2007;

   Consolidated Statements of Stockholders Equity for each of the three years ended December 31, 2009, 2008, and 2007; and

   Notes to the Consolidated Financial Statements.

2. **Financial Statement Schedules:**

   Report of Independent Registered Public Accounting Firm;

   Schedule I Parent Company Condensed Financial Statements; and

   Schedule II Valuation and Qualifying Accounts.

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

3. **Exhibits**

Exhibit 1.1	Underwriting Agreement entered into by Chesapeake Utilities Corporation and Robert W. Baird & Co. Incorporated and A.G. Edwards & Sons, Inc., on November 15, 2007, relating to the sale and issuance of 600,300 shares of Chesapeake s common stock, is incorporated herein by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed November 16, 2007, File No. 001-11590.
Exhibit 2.1	Agreement and Plan of Merger between Chesapeake Utilities Corporation and Florida Public Utilities Company dated April 17, 2009, is incorporated herein by reference to Exhibit 2.1 of our Current Report on Form 8-K, filed April 20, 2009, File No. 001-11590.
Exhibit 3.1	Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 1998, File No. 001-11590.
Exhibit 3.2	Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 11, 2008, are incorporated herein by reference to Exhibit 3 of the Company s Current Report on Form 8-K, filed December 16, 2008, File No. 001-11590.
Exhibit 4.1	Form of Indenture between Chesapeake and Boatmen s Trust Company, Trustee, with respect to the 8 1/4% Convertible Debentures is incorporated herein by reference to Exhibit 4.2 of our Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.

Table of Contents

Exhibit 4.2	Note Purchase Agreement, entered into by the Company on October 2, 1995, pursuant to which Chesapeake privately placed $10 million of its 6.91% Senior Notes, due in 2010, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 4.3	Note Purchase Agreement, entered into by Chesapeake on December 15, 1997, pursuant to which Chesapeake privately placed $10 million of its 6.85% Senior Notes due in 2012, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 4.4	Note Purchase Agreement entered into by Chesapeake on December 27, 2000, pursuant to which Chesapeake privately placed $20 million of its 7.83% Senior Notes, due in 2015, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 4.5	Note Agreement entered into by Chesapeake on October 31, 2002, pursuant to which Chesapeake privately placed $30 million of its 6.64% Senior Notes, due in 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.
Exhibit 4.6	Note Agreement entered into by Chesapeake on October 18, 2005, pursuant to which Chesapeake, on October 12, 2006, privately placed $20 million of its 5.5% Senior Notes, due in 2020, with Prudential Investment Management, Inc., is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
Exhibit 4.7	Note Agreement entered into by Chesapeake on October 31, 2008, pursuant to which Chesapeake, on October 31, 2008, privately placed $30 million of its 5.93% Senior Notes, due in 2023, with General American Life Insurance Company and New England Life Insurance Company, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 4.8	Form of Senior Debt Trust Indenture between Chesapeake Utilities Corporation and the trustee for the debt securities is incorporated herein by reference to Exhibit 4.3.1 of our Registration Statement on Form S-3A, Reg. No. 333-135602, dated November 6, 2006.
Exhibit 4.9	Form of Subordinated Debt Trust Indenture between Chesapeake Utilities Corporation and the trustee for the debt securities is incorporated herein by reference to Exhibit 4.3.2 of our Registration Statement on Form S-3A, Reg. No. 333-135602, dated November 6, 2006.
Exhibit 4.10	Form of debt securities is incorporated herein by reference to Exhibit 4.4 of our Registration Statement on Form S-3A, Reg. No. 333-135602, dated November 6, 2006.
Exhibit 4.11	Form of Indenture of Mortgage and Deed of Trust between Florida Public Utilities Company and the trustee, dated September 1, 1942 for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company s Registration No. 2-6087.

Exhibit 4.12 Fourteenth Supplemental Indenture entered into by Florida Public Utilities Company on September 1, 2001, pursuant to which Florida Public Utilities Company, on September 1, 2001, privately placed $15,000,000 of its 6.85% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(b) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.

Exhibit 4.13 Fifteenth Supplemental Indenture entered into by Florida Public Utilities Company on November 1, 2001, pursuant to which Florida Public Utilities Company, on November 1, 2001, privately placed $14,000,000 of its 4.90% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(c) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608

Table of Contents

Exhibit 4.14	Twelfth Supplemental Indenture entered into by Florida Public Utilities on May 1, 1988, pursuant to which Florida Public Utilities Company, on May 1, 1988, privately placed $10,000,000 and $5,000,000 of its 9.57% First Mortgage Bonds and 10.03% First Mortgage Bonds, respectively, are incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 1988.
Exhibit 4.15	Thirteenth Supplemental Indenture entered into by Florida Public Utilities Company on June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 1992.
Exhibit 10.1*	Chesapeake Utilities Corporation Cash Bonus Incentive Plan, dated January 1, 2005, is incorporated herein by reference to Exhibit 10.3 of our Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-11590.
Exhibit 10.2*	Chesapeake Utilities Corporation Directors Stock Compensation Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.3*	Chesapeake Utilities Corporation Employee Stock Award Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.4*	Chesapeake Utilities Corporation Performance Incentive Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.5*	Deferred Compensation Program, amended and restated as of January 1, 2009, is incorporated herein by reference to Exhibit 10.5 of the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.6*	Executive Employment Agreement dated December 29, 2006, by and between Chesapeake Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.7 of our Annual Report on Form 10-K for the year ended December 31, 2006, File No. 001-11590.
Exhibit 10.7*	Amendment to Executive Employment Agreement, effective January 1, 2009, by and between Chesapeake Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.7 of the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.8*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.

Exhibit 10.9*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.10*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.11*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.4 of the Company s Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.

Exhibit 10.12*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Joseph Cummiskey, is incorporated herein by reference to Exhibit 10.5 of the Company s Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.13*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.14*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.12 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.15*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.13 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.16*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.14 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.17*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.18*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.16 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.19*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.17 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.20*	

	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.21*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.

Exhibit 10.22*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.20 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.23*	Form of Performance Share Agreement effective January 7, 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of John R. Schimkaitis, Michael P. McMasters, Beth W. Cooper and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.26 on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.24*	Form of Performance Share Agreement effective January 6, 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of John R. Schimkaitis, Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, and Joseph Cummiskey is filed herewith.
Exhibit 10.25*	Performance Share Agreement dated January 20, 2010 for the period 2010 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Joseph Cummiskey is filed herewith.
Exhibit 10.26*	Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.28 of the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.27*	Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.29 of the Company s Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.28*	Amended and Restated Electric Service Contract between Florida Public Utilities Company and JEA dated November 6, 2008, is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company s Current Report on Form 8-K, filed on November 6, 2008, File No. 001-10908.
Exhibit 10.29*	Networking Operating Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.30*	Network Integration Transmission Service Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.4 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.31*	

	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2016 (Contract No. 107033), is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.32*	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to March 2022 (Contract No. 107034), is incorporated herein by reference to Exhibit 10.2 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.

Exhibit 10.33*	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2022 (Contract No. 107035), is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company s Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 12	Computation of Ratio of Earning to Fixed Charges is filed herewith.
Exhibit 14.1	Code of Ethics for Financial Officers is filed herewith.
Exhibit 14.2	Business Code of Ethics and Conduct is filed herewith.
Exhibit 21	Subsidiaries of the Registrant is filed herewith.
Exhibit 23.1	Consent of Independent Registered Public Accounting Firm is filed herewith.
Exhibit 31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d-14(a), dated March 8, 2010, is filed herewith.
Exhibit 31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d-14(a), dated March 8, 2010, is filed herewith.
Exhibit 32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 8, 2010, is filed herewith.
Exhibit 32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 8, 2010, is filed herewith.

* Management contract or compensatory plan or agreement.

Table of Contents

Signatures

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

Chesapeake Utilities Corporation

By: /s/ John R. Schimkaitis
John R. Schimkaitis
Vice Chairman and Chief Executive Officer
Date: March 8, 2010

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

/s/ Ralph J. Adkins	/s/ John R. Schimkaitis
Ralph J. Adkins, Chairman of the Board and Director Date: February 24, 2010	John R. Schimkaitis, Vice Chairman, Chief Executive Officer and Director Date: March 8, 2010
/s/ Beth W. Cooper	/s/ Eugene H. Bayard
Beth W. Cooper, Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer) Date: March 8, 2010	Eugene H. Bayard, Director Date: February 24, 2010
/s/ Richard Bernstein	/s/ Thomas J. Bresnan
Richard Bernstein, Director Date: February 24, 2010	Thomas J. Bresnan, Director Date: March 8, 2010
/s/ Thomas P. Hill, Jr.	/s/ Dennis S. Hudson, III
Thomas P. Hill, Jr., Director Date: February 24, 2010	Dennis S. Hudson, III, Director Date: February 24, 2010
/s/ Paul L. Maddock, Jr.	/s/ J. Peter Martin
Paul L. Maddock, Jr., Director Date: February 24, 2010	J. Peter Martin, Director Date: February 24, 2010
/s/ Michael p. Mcmasters	/s/ Joseph E. Moore, Esq
Michael P. McMasters, President, Chief Operating Officer and Director Date: March 8, 2010	Joseph E. Moore, Esq., Director Date: February 24, 2010

/s/ Calvert A. Morgan, Jr	/s/ Dianna F. Morgan
Calvert A. Morgan, Jr., Director Date: February 24, 2010	Dianna F. Morgan, Director Date: February 24, 2010

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

The audit referred to in our report dated March 8, 2010 relating to the consolidated financial statements of Chesapeake Utilities Corporation as of December 31, 2009 and 2008 and for each of the years in the three-year period ended December 31, 2009, which is contained in Item 8 of this Form 10-K also included the audits of the financial statement schedules listed in Item 15(a) 2. These financial statement schedules are the responsibility of the Chesapeake Utilities Corporation s management. Our responsibility is to express an opinion on these financial statement schedules based on our audits.

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

/s/ ParenteBeard LLC

ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2010

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Balance Sheets

Assets *(in thousands)*	**December 31, 2009**	**December 31, 2008**
Total property, plant and equipment	**$ 191,440**	$ 185,416
Less: Accumulated depreciation and amortization	**(46,297)**	(46,158)
Plus: Construction work in progress	**1,338**	408
Net property, plant and equipment	**146,481**	139,666
Investments	**1,959**	1,601
Investments in subsidiaries	**160,150**	73,410
Current Assets		
Cash and cash equivalents	**973**	1,534
Accounts receivable (less allowance for uncollectible accounts of $458 and $398, respectively)	**9,356**	11,848
Accrued revenue	**4,936**	4,721
Accounts receivable from affiliates	**56,587**	61,139
Propane inventory, at average cost	**624**	648
Other inventory, at average cost	**971**	983
Regulatory assets	**1,205**	824
Storage gas prepayments	**6,144**	9,492
Income taxes receivable	**822**	3,547
Deferred income taxes	**1,909**	1,743
Prepaid expenses	**3,047**	1,974
Other current assets	**79**	79
Total current assets	**86,653**	98,532
Deferred Charges and Other Assets		
Long-term receivables	**331**	512
Regulatory assets	**3,610**	2,060
Other deferred charges	**479**	453
Total deferred charges and other assets	**4,420**	3,025
Total Assets	**$ 399,663**	$ 316,234

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Balance Sheets

Capitalization and Liabilities *(in thousands)*	**December 31, 2009**	**December 31, 2008**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 12,000,000 shares)	**$ 4,572**	$ 3,323
Additional paid-in capital	**144,502**	66,681
Retained earnings	**63,231**	56,817
Accumulated other comprehensive loss	**(2,865)**	(3,748)
Deferred compensation obligation	**739**	1,549
Treasury stock	**(739)**	(1,549)
Total stockholders equity	**209,440**	123,073
Long-term debt, net of current maturities	**79,611**	86,382
Total capitalization	**289,051**	209,455
Current Liabilities		
Current portion of long-term debt	**6,636**	6,636
Short-term borrowing	**30,023**	33,000
Accounts payable	**9,157**	9,587
Customer deposits and refunds	**4,410**	5,558
Accrued interest	**1,003**	1,023
Dividends payable	**2,959**	2,082
Accrued compensation	**2,450**	1,994
Regulatory liabilities	**5,934**	2,429
Other accrued liabilities	**1,647**	1,602
Total current liabilities	**64,219**	63,911
Deferred Credits and Other Liabilities		
Deferred income taxes	**16,494**	13,204
Deferred investment tax credits	**157**	193
Regulatory liabilities	**695**	598
Environmental liabilities	**531**	511
Other pension and benefit costs	**5,674**	6,914
Accrued asset removal cost	**18,248**	17,740
Other liabilities	**4,594**	3,708

Total deferred credits and other liabilities		**46,393**		42,868
Other commitments and contingencies				
Total Capitalization and Liabilities	**$**	**399,663**	$	316,234

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Statements of Income

For the Years Ended December 31, *(in thousands)*	**2009**	**2008**	**2007**
Operating Revenues	**$ 101,577**	$ 103,733	$ 119,402
Operating Expenses			
Cost of sales	**62,339**	65,446	83,076
Operations	**18,487**	16,039	16,454
Transaction-related costs	**1,478**	1,153	
Maintenance	**1,535**	1,303	1,409
Depreciation and amortization	**4,194**	3,918	4,032
Other taxes	**3,564**	3,380	2,989
Total operating expenses	**91,597**	91,239	107,960
Operating Income	**9,980**	12,494	11,442
Income from equity investments	**12,042**	7,781	7,679
Other income (loss), net of other expenses	**(30)**	(106)	220
Interest charges	**3,066**	3,026	3,195
Income Before Income Taxes	**18,926**	17,143	16,146
Income taxes	**3,029**	3,536	2,948
Net Income	**$ 15,897**	$ 13,607	$ 13,198

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Statements of Cash Flows

For the Years Ended December 31, *(in thousands)*	2009	2008	2007
Operating Activities			
Net Income	**$ 15,897**	$ 13,607	$ 13,198
Adjustments to reconcile net income to net operating cash:			
Equity earnings in subsidiaries	**(12,042)**	(7,781)	(7,679)
Depreciation and amortization	**4,190**	3,918	4,268
Depreciation and accretion included in other costs	**1,773**	1,389	1,646
Deferred income taxes, net	**2,821**	5,147	(156)
Gain on sale of assets			(205)
Unrealized (gain) loss on investments	**(212)**	509	(123)
Employee benefits and compensation	**1,217**	152	1,004
Share based compensation	**1,306**	820	990
Other, net	**8**	11	7
Changes in assets and liabilities:			
Sale (purchase) of investments	**(146)**	(201)	229
Accounts receivable and accrued revenue	**(16,770)**	(3,016)	(2,315)
Propane inventory, storage gas and other inventory	**3,383**	(3,854)	1,427
Regulatory assets	**(1,825)**	606	(526)
Prepaid expenses and other current assets	**(1,050)**	(516)	(179)
Other deferred charges	**(72)**	(8)	(61)
Long-term receivables	**181**	199	76
Accounts payable and other accrued liabilities	**9,832**	3,323	(403)
Income taxes receivable	**2,791**	(3,113)	147
Accrued interest	**(20)**	158	32
Customer deposits and refunds	**(1,147)**	34	1,423
Accrued compensation	**352**	377	326
Regulatory liabilities	**3,603**	(2,379)	1,941
Other liabilities	**886**	(23)	(151)
Net cash provided by operating activities	**14,956**	9,359	14,916
Investing Activities			
Property, plant and equipment expenditures	**(12,615)**	(16,328)	(15,464)
Proceeds from sale of assets			205
Proceeds from investments	**1,000**	500	900
Cash acquired in the merger, net of cash paid	**(16)**		
Environmental expenditures	**(86)**	(480)	(228)
Net cash used by investing activities	**(11,717)**	(16,308)	(14,587)

Financing Activities						
Inter-company receivable (payable)		**13,379**		4,302		(4,331)
Common stock dividends		**(7,957)**		(7,810)		(7,030)
Issuance of stock for Dividend Reinvestment Plan		**392**		(118)		299
Change in cash overdrafts due to outstanding checks		**835**		(684)		(541)
Net borrowing (repayment) under line of credit agreements		**(3,812)**		(11,980)		18,651
Proceeds from issuance of long-term debt				29,961		
Repayment of long-term debt		**(6,637)**		(7,637)		(7,637)
Net cash provided by (used in) financing activities		**(3,800)**		6,034		(589)
Net Decrease in Cash and Cash Equivalents		**(561)**		(915)		(260)
Cash and Cash Equivalents Beginning of Period		**1,534**		2,449		2,709
Cash and Cash Equivalents End of Period	**$**	**973**	$	1,534	$	2,449

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

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements

Notes to Financial Information

These condensed financial statements represent the financial information of Chesapeake Utilities Corporation (parent company).

For information concerning Chesapeake s debt obligations, see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-term Debt, and Note K, Short-term Borrowing.

For information concerning Chesapeake s material contingencies and guarantees, see Item 8 under the heading Notes to the Consolidated Financial Statements Note O, Environmental Commitments and Contingencies, and Note P, Other Commitments and Contingencies.

Chesapeake s wholly-owned subsidiaries are accounted for using the equity method of accounting.

Table of Contents

Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts[1]	Deductions[2]	Balance at End of Year
Reserve Deducted From Related Assets Reserve for Uncollectible Accounts					
(In thousands)					
2009	**$ 1,159**	**$ 1,138**	**$ 616**	$ **(1,304)**	**$ 1,609**
2008	$ 952	$ 1,186	$ 241	$ (1,220)	$ 1,159
2007	$ 662	$ 818	$ 26	$ (554)	$ 952

(1) Recoveries.

(2) Uncollectible accounts charged off.