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November 2, 2011

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Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Application by Chesapeake Utilities Corporation for Authorization to issue Common Stock, Preferred Stock, and Secured and/or Unsecured Debt, and to Enter into Agreements for Interest Rate Swap Products, Equity Products and Other Financial Derivatives and to Exceed Limitation Places on Short Term Borrowings in 2011

Dear Ms Cole:

Enclosed for filing, please find an original and 3 copies of the Application of Chesapeake Utilities Corporation for Authority to Issue Stock, and Secured and/or Unsecured Debt, and to Enter into Agreements for Interest Rate Swap Products, Equity Products and Other Financial Derivatives and to Exceed Limitation Places on Short Term Borrowings in 2012, along with a copy of the pleading on CD in Word format. A copy of this filing has also been provided to the Office of Public Counsel.

Your assistance in this matter is greatly appreciated. If you have any questions, please do not hesitate to contact me.

Sincerely,

Beth Keating

Beth Keating
Gunster, Yoakley, & Stewart, P.A.
215 S. Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt, and to Enter into Agreements For Interest Rate Swap Products, Equity Products and Other Financial Derivatives and to Exceed Limitation Placed on Short-Term Borrowings in 2012	)

APPLICATION BY CHESAPEAKE UTILITIES CORPORATION FOR AUTHORIZATION TO ISSUE COMMON STOCK, PREFERRED STOCK AND SECURED AND/OR UNSECURED DEBT, AND TO ENTER INTO AGREEMENTS FOR INTEREST RATE SWAP PRODUCTS, EQUITY PRODUCTS AND OTHER FINANCIAL DERIVATIVES, AND TO EXCEED LIMITATION PLACED ON SHORT-TERM BORROWINGS IN 2012

Chesapeake Utilities Corporation (Chesapeake, the Company or Applicant) respectfully files this Application, pursuant to Section 366.04 (1), Florida Statutes, seeking authority in 2012 to issue up to 5,875,782 shares of Chesapeake common stock; up to 1,000,000 shares of Chesapeake preferred stock; up to $120,000,000 in secured and/or unsecured debt; to enter into agreements for up to $40,000,000 in Interest Rate Swap Products, Equity Products and other Financial Derivatives; and to obtain authorization to exceed the limitation placed on short-term borrowings by Section 366.04, Florida Statutes, so as to issue short-term obligations in 2012, in an amount not to exceed $100,000,000.

1. Name and principal business offices of Applicant:

   a) Chesapeake Utilities Corporation
   P.O. Box 615
   909 Silver Lake Boulevard
   Dover, Delaware 19904

   b) Chesapeake Utilities Corporation
   Florida Division
   1501 Sixth Street, NW
   Winter Haven, Florida 33881

c) Florida Public Utilities Company (a wholly owned subsidiary of Chesapeake Utilities Corporation)
401 South Dixie Highway
West Palm Beach, FL 33401

d) Indiantown Gas Company
401 South Dixie Highway
West Palm Beach, FL 33401

2. Incorporated:

Chesapeake Utilities Corporation – Incorporated under the laws of the state of Delaware in 1947 and qualified to do business in Florida, Maryland, and Pennsylvania

Florida Public Utilities Company – Incorporated under the laws of the state of Florida in 1924 and qualified to do business in Florida

3. Person authorized to receive notices and communications in this respect:

Beth Keating, Esquire
Gunster, Yoakley & Stewart, P.A.
Suite 618
215 South Monroe Street
Tallahassee, Florida 32301
(850) 521-1706

Attorneys for Chesapeake Utilities Corporation

4. Capital Stock and Funded Debt

Chesapeake has authority by provisions contained in the Certificate of Incorporation, as amended, to issue common stock as follows:

a) Common stock having a par value of $0.4867 per share.

b) Amount authorized: 25,000,000 shares.

c) Amount outstanding as of June 30, 2011 : 9,562,318

d) Amount held in Treasury: 0 shares.

e) Amount pledged by Applicant: None.

f) Amount owned by affiliated corporations: None.

g) Amount held in any fund: None.

Chesapeake has authority by provisions contained in its Certificate of Incorporation, as amended, to issue preferred stock as follows:

a) Preferred stock having a par value of $0.01 per share.

b) Amount authorized: 2,000,000 shares.

c) Amount outstanding as of June 30, 2011: 0 shares.

d) Amount held in Treasury: None.

e) Amount pledged by Applicant: None.

f) Amount owned by affiliated corporations: None.

g) Amount held in any fund: None.

The funded indebtedness by class and series are as follows:

(a) 1 Chesapeake Utilities Corporation 8.25% Convertible Debentures due March 1, 2014 are convertible prior to maturity, unless previously redeemed, into shares of common stock of Chesapeake at a conversion price of $17.01 per share. Interest on the Debentures is payable on the first day of March and September, commencing September 1, 1989. The Debentures are redeemable at 100% of the principal amount plus accrued interest (i) on March 1 in any year, commencing in 1991, at the option of the holder and (ii) at any time within 60 days after request on behalf of a deceased holder. At Chesapeake's option, beginning March 1, 1990, the Debentures may be redeemed in whole or in part at redemption prices declining from 107.25%, plus accrued interest. No sinking fund will be established to redeem the Debentures. As of June 30, 2011, there is a remaining balance of $1,221,000 for this issue.

(a) 2 Chesapeake Utilities Corporation 6.85% Unsecured Senior Notes due January 1, 2012 and issued on December 15, 1997 in the principal amount of $10,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to January 1, 2003; thereafter, principal shall be payable, in addition to interest on the unpaid balance, over ten (10) years at the rate of $1,000,000 per annum. As of June 30, 2011, there is a remaining balance of $1,000,000 for this issue.

(a) 3 Chesapeake Utilities Corporation 7.83% Unsecured Senior Notes due January 1, 2015 and issued on December 29, 2000 in the principal amount of $20,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to January 1, 2006; thereafter, principal shall be payable, in addition to interest on the unpaid balance, over ten (10) years at the rate of $2,000,000 per annum. As of June 30, 2011, there is a remaining balance of $8,000,000 for this issue.

(a) 4 Chesapeake Utilities Corporation 6.64% Unsecured Senior Notes due October 31, 2017 and issued on October 31, 2002 in the principal amount of $30,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to October 31, 2007; thereafter, principal shall be payable, in addition to interest on the unpaid balance, over eleven (11) years at the rate of $2,727,272 per annum. As of June 30, 2011, there is a remaining balance of $19,090,909 for this issue.

(a) 5 Chesapeake Utilities Corporation 5.50% Unsecured Senior Notes due October 12, 2020 and issued on October 12, 2006 in the principal amount of $20,000,000 bearing interest payable quarterly with provisions for payment of interest only prior to October 12, 2011; thereafter, principal shall be payable, in addition to interest on the unpaid balance, for ten (10) years at the rate of $2,000,000 per annum. As of June 30, 2011, there is a remaining balance of $20,000,000 for this issue.

(a) 6 Chesapeake Utilities Corporation 5.93% Unsecured Senior Notes due October 31, 2023 and issued on October 31, 2008 in the principal amount of $30,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to October 31, 2014; thereafter, principal shall be payable, in addition to interest on the unpaid balance for ten (10) years at the rate of $3,000,000 per annum. Accordingly, as of June 30, 2011, there is a balance of $30,000,000 for this issue.

(a) 7 Florida Public Utilities Company 9.57% Secured First Mortgage Bonds due May 1, 2018 and issued on May 1, 1988 in the principal amount of $10,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to May 1, 2008; thereafter, principal shall be payable, in addition to interest on the unpaid balance for eleven (11) years at the rate of $909,091 per annum. Accordingly, as of June 30, 2011, there is a balance of $6,363,637 for this issue.

(a) 8 Florida Public Utilities Company 10.03% Secured First Mortgage Bonds due May 1, 2018 and issued on May 1, 1988 in the principal amount of $5,500,000 bearing interest payable semi-annually with provisions for payment of interest only prior to May 1, 2008; thereafter, principal shall be payable, in addition to interest on the unpaid balance for eleven (11) years at the rate of $500,000 per annum. Accordingly, as of June 30, 2011, there is a balance of $3,500,000 for this issue.

(a) 9 Florida Public Utilities Company 9.08% Secured First Mortgage Bonds due June 1, 2022 and issued on June 1, 1992 in the principal amount of $8,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to June 1, 2022; thereafter, principal shall be payable in full. Accordingly, as of June 30, 2011, there is a balance of $8,000,000 for this issue.

(a) 10 On March 16, 2010, the Company entered into a new $29.1 million credit facility with one of its commercial lenders. This credit facility, which was structured in the form of a term note, was utilized to redeem FPU's 6.85 percent and 4.90 percent First Mortgage Bonds that were acquired as part of the merger in October 2009 and then redeemed in January 2010. The Company received an advance of the full amount under the term note under the LIBOR pricing option and has borrowed under the term note for a nine-month period, with the facility maturing in one year. On June 30, 2010 the Company entered into an agreement with Metropolitan Life Insurance Company to refinance the two redeemed First Mortgage Bonds mentioned above with unsecured senior notes to be drawn at the Company's discretion between June 30, 2010 and June 30, 2012. On June 24, 2011 Chesapeake Utilities Corporation issued 5.68% Unsecured senior Notes due June 30, 2026 in the principal amount of $29,000,000 bearing interest payable semi-annually with provisions for payment of interest only prior to June 30, 2016; thereafter, principal shall be payable, in addition to interest on the unpaid balance for ten (10) years at the rate of $2,900,000 per annum. Accordingly, as of June 30, 2011, there is a balance of $29,000,000 on this issue.

As of the filing date, Chesapeake has four unsecured bank lines of credit with two commercial lenders. Chesapeake currently maintains a total short-term borrowing line capacity of $100,000,000. The Company has committed short-term borrowing capacity of $60,000,000 (held through two separate lines of credit of $30,000,000 with two lenders), and uncommitted short-term borrowing capacity of $40,000,000 (held through two separate lines of credit of $20,000,000 with two lenders). As of June 30, 2011, the total short-term borrowing outstanding under the bank lines of credit was $3,350,312.

5. Authorizations Requested

Chesapeake requests authorization from the FPSC to issue up to 375,782 new shares of its common stock during 2012 for the purpose of administering Chesapeake's Retirement Savings Plan, Performance Incentive Plan, Dividend Reinvestment and Stock Purchase Plan, conversion of the Company's Convertible Debentures, Directors Stock Compensation Plan, and Employee Stock Awards Plan. The share breakdown for each specific purpose is as follows:

Number of Shares	Purpose
70,000	Issuance pursuant to the Company's Retirement Savings Plan.
100,000	Issuance under the terms of the Company's Performance Incentive Plan.

120,000	Issuance pursuant to the Company's Dividend Reinvestment and Stock Purchase Plan.
65,782	Issuance under the terms of the Company's outstanding 8 ¼% Convertible Debentures.
15,000	Issuance pursuant to the Company's Directors Stock Compensation Plan.
5,000	Issuance under the terms of the Company's Employee Stock Awards Plan.

In addition, Chesapeake is requesting FPSC authorization to issue up to 500,000 shares of Chesapeake stock or an equity-linked instrument equivalent in value in 2012 to permanently finance Chesapeake's ongoing capital expenditure program. The capital expenditure program is subject to continuous review and modification and is funded from short-term borrowings and cash provided by operating activities. The Company, in an effort to manage its capital structure, may from time to time, permanently finance its short-term borrowings through the issuance of common stock or an equity-linked instrument, as opposed to long-term debt.

Chesapeake requests FPSC authorization to issue up to $60,000,000 in secured an/or unsecured debt during 2012 for general corporate purposes including, but not limited to, working capital, retirement of short-term debt, retirement of long-term debt and capital improvements.

Chesapeake is also requesting FPSC authorization during 2012 to issue up to 5,000,000 shares of common stock and up to $60,000,000 in secured and/or unsecured debt for possible acquisitions. Due to the nature of typical cash for stock acquisitions, the $60,000,000 in secured and/or unsecured debt may be initially issued through a bridge loan in the form of notes held by banks or some similar form of short-term obligations. For this reason, Chesapeake seeks FPSC authorization to exceed the limitation placed on short-term borrowings by Section 366.04, Florida Statutes, so as to issue short-term obligations in an amount not to exceed $100,000,000 during 2012. The bridge financing would subsequently be refinanced as unsecured long-term debt with an estimated rate of interest of up to 300 basis points above U.S. Treasury rates (or extrapolated U.S. Treasury rates) with equivalent average life.

Chesapeake is also requesting authority to issue up to 1,000,000 shares of Chesapeake preferred stock in 2012, for possible acquisitions, financing transactions, and other general corporate purposes, including potential distribution under the Company's Shareholder Rights Agreement ("Rights Agreement") adopted by the Board of Directors on August 20, 1999, and subsequently, modified and extended by the Board of Directors on September 12, 2008. On September 12, 2008, the Board extended the expiration of the Rights from August 20, 2009 to August 20, 2019 and increased the Exercise Price per share from $54.56 to $105 A copy of the First Amendment to Rights Agreement and Securities and Exchange Commission Form 8-K pursuant to Chesapeake Utilities Corporation's First Amendment to Rights Agreement has been previously filed with the FPSC within Exhibit D of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt, and to Enter into Agreements for Interest Rate Swap Products, Equity Products and Other Financial Derivatives and to Exceed Limitation Placed on Short-Term Borrowings in 2009, Docket No. 080635-GU, dated November 19, 2009, and is hereby incorporated by reference.

Chesapeake further seeks FPSC approval to enter into financial agreements with institutions in 2012 to negotiate and execute financial derivatives enabling the Company to lock in its future financing costs and minimize its risk. A financial derivative is a risk-shifting agreement, the value of which is derived from the value of an underlying asset. The underlying asset could be a physical commodity, an interest rate, a company's stock, a stock index, a currency, or virtually any other tradable instrument upon which two parties can agree. A financial derivative can be used for hedging, protecting against financial risk, or can be used to speculate on the movement of commodity or security prices, interest rates or the levels of financial indices. Financial derivatives fall into two categories. One consists of customized, privately negotiated derivatives, referred to as over-the-counter (OTC) derivatives or swaps. The other category consists of standardized, exchangeable derivatives, known generically as futures. In addition, there are various types of products within each of the two categories. The Company has attempted to identify below some of the financial derivatives that the Company may evaluate in 2012, although the listing is not intended to be all-inclusive. Rather, the Company seeks approval to evaluate and employ those financial derivatives that would mitigate its financial risk associated with a particular financing transaction(s).

Chesapeake is proposing to have the flexibility and authority to enter into the following (a) Treasury rate locks, credit spread locks, interest rate swaps, collars, caps and/or floors (the "Interest Rate Swap Products"); (b) equity collars, floors, prepaid forward contracts, covered calls, forward sales and purchases and/or equity-linked instruments (the "Equity Products"); or (c) any other Financial Derivatives that meet the objectives described above on such terms as Chesapeake considers to be appropriate, provided that the notional amount(s) for said Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives do not, in the aggregate, exceed the sum of $40,000,000.

Chesapeake Utilities Corporation allocates funds to the Florida Division, Florida Public Utilities and Indiantown Gas Company on an as-needed basis.

6. Purposes for which Securities are to be issued:

(a) Chesapeake's Retirement Savings Plan ("RSP") was implemented on February 1, 1977. As of June 30, 2011, the RSP had 380 active participants; a total market valuation of approximately $50,039,008 and 503,827 shares of the Company's common stock. Chesapeake's 401k Plan was amended to be a "safe harbor" plan. Effective January 1, 2011 the Company matches 100% of the participants' contributions up to six percent of the eligible compensation in cash and any supplemental contributions will generally be made in Chesapeake stock. Prior to January 1, 2011 the Company match was primarily made in Chesapeake stock. In conjunction with the adoption of a "safe harbor" plan, the plan document was amended. A copy of the amended plan document is attached as Exhibit B.

As of June 30, 2011, FPU's 401k Plan had 372 active participants; a total market value of approximately $12,253,042 and no shares of the Company's common stock. We expect to consolidate the Chesapeake and FPU 401k plans in 2012, which would increase the total participants in the plan to over 700.

To continue to balance the composition of debt and equity, Chesapeake wants to maintain flexibility in how the RSP is funded, i.e., with new shares of its stock, buying shares on the open market, and/or a combination of both funding methods. In addition, management is evaluating the possibility that a discretionary contribution for FPU's 401(k) Plan will be funded with Chesapeake stock.

On June 23, 1992, the Delaware Public Service Commission issued Order No. 3425 approving the issuance of up to 100,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's RSP. Please note that this Order by the Delaware Public Service Commission is "open ended" in the sense that there is no time limit by which the approved securities need to be issued. A copy of the Order has been previously filed with the FPSC within Exhibit J of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 931112-GU, dated November 17, 1993, and is hereby incorporated by reference. On July 13, 1999, the Delaware Public Service Commission issued Order No. 5165 approving the issuance of an additional 100,000 new shares of Chesapeake common stock for the purpose of administering the RSP. Please note that this Order by the Delaware Public Service Commission is also "open ended" in the sense that there is no time limit by which approved securities need to be issued. A copy of this Order has been previously filed with the FPSC within Exhibit C of the Application by Chesapeake Utilities Corporation for Authorization to issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed Limitation Placed on Short-Term Borrowings in 2000, Docket No. 991631-GU, dated October 20, 1999, and is hereby incorporated by reference. On December 19, 2000, the Delaware Public Service Commission issued Order No. 5609 approving the issuance of an additional 300,000 new shares of Chesapeake common stock for the purpose of administering the RSP.

Please note that this Order by the Delaware Public Service Commission is also "open ended" in the sense that there is no time limit by which approved securities need to be issued. A copy of this Order has been previously filed with the FPSC as Exhibit E of the Consummation Report of Securities Issued by Chesapeake Utilities Corporation, Docket No. 991631-GU, dated March 29, 2001, and is hereby incorporated by reference. On May 4, 2010, the Delaware Public Service Commission issued Order No. 7769 approving the issuance of an additional 600,000 new shares of Chesapeake common stock for the purpose of administering the RSP. Please note that this Order by the Delaware Public Service Commission is also "open ended" in the sense that there is no time limit by which approved securities need to be issued. A copy of the order was previously filed with the FPSC as Exhibit C of Docket No. 100444-GU dated November 16, 2010. Pursuant to these Orders, Chesapeake has issued 519,516 new shares of common stock for the RSP as of June 30, 2011. Thus, there remains to be issued 580,484 shares as authorized by the Delaware Public Service Commission. The FPSC approved the issuance and sale of up to 70,000 shares of common stock for the Plan during 2011 by Order No. PSC-10-0744-FOF-GU issued on December 27, 2010. Chesapeake now seeks FPSC authorization to issue up to 70,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's Plan during 2012.

(b) On May 19, 1992, the common stock shareholders of Chesapeake voted in favor of adopting the Chesapeake Utilities Corporation Performance Incentive Plan ("PIP"). On May 19, 1998, the common stock shareholders of Chesapeake approved several amendments to the PIP. A copy of the amended PIP agreement has been previously filed with the FPSC within

Exhibit C of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 981213-GU, dated September 23, 1998, and is hereby incorporated by reference.

The purposes of the PIP are (1) to further the long-term growth and earnings of the Company by providing incentives and rewards to those executive officers and other key employees of the Company and its subsidiaries who are in positions in which they can contribute significantly to the achievement of that growth; (2) to encourage those employees to obtain proprietary interests in the Company and to remain as employees of the Company; and (3) to assist the Company in recruiting able management personnel.

To accomplish these objectives, the PIP authorizes the grant of nonqualified stock options, performance shares of the Company's common stock and stock appreciation rights, or any combination thereof. The PIP, as it was originally adopted by the common stock shareholders of Chesapeake in 1992, provided that over a ten-year period beginning in 1992, any one or more types of awards for up to a total of 200,000 shares of Chesapeake's common stock may be granted. On June 23, 1992, the Delaware Public Service Commission issued Order No. 3425 approving the issuance of up to 200,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's PIP. A copy of this Order has been previously filed with the FPSC within Exhibit J of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 931112-GU, dated November 17, 1993, and is hereby incorporated by reference. The amendments to the PIP adopted by the common stock shareholders of Chesapeake on May 19, 1998 changed the terms and provisions of the PIP as follows: (1) the aggregate number of shares of common stock subject to awards was increased from 200,000 shares to 400,000 shares; (2) the term of the PIP was extended for five years through December 31, 2005; and (3) the Board of Directors was granted greater flexibility to amend, modify or terminate the PIP, subject to shareholder approval requirements imposed by applicable law. On July 13, 1999, the Delaware Public Service Commission issued Order No. 5165 approving the issuance of an additional 200,000 new shares of Chesapeake common stock for the purpose of administering the PIP, coinciding with these amendments. A copy of this Order has been previously filed with the FPSC within Exhibit C of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed Limitation Placed on Short-Term Borrowings in 2000, Docket No. 991631-GU, dated October 20, 1999, and is hereby incorporated by reference.

The pre-existing PIP expired on December 31, 2005 and the Company's current PIP was effective January 1, 2006. Stock awards granted prior to 2006, were under the authority of the pre-existing PIP. Stock awards granted in 2006 through 2014, to the extent earned and awarded in such years, have been and will continue to be issued under the authority of the current PIP.

On February 24, 2005, Chesapeake's Board of Directors adopted the current PIP, which applied to performance beginning January 1, 2006, and approved 400,000 shares of common stock to be authorized and reserved for issuance. The current PIP as adopted by the common shareholders of Chesapeake on May 5, 2005 allows for the issuance of restricted stock in the form of performance share awards. In addition, the current PIP, allows performance shares to be awarded to those key employees of the Company whom a designated committee, composed of independent directors chosen by the Board determines, are in positions to contribute significantly to the long-term growth, development, and financial success of the Company, and will encourage those employees to obtain proprietary interest in the Company and to remain as employees of the Company as well as to assist the Company in recruiting able management personnel. Under the current PIP, no more than 25,000 shares are to be awarded to any one executive in any calendar year. The current PIP expires on December 31, 2014. On April 26, 2005, the Delaware Public Service Commission issued Order No. 6607 approving the issuance of 400,000 shares of Chesapeake common stock for the purpose of administering the current PIP. A copy of the Application and Order have been previously filed with the FPSC within Exhibit D, as well as Chesapeake's Performance Incentive Plan document for 400,000 shares within Exhibit E, of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed Limitation Placed on Short-Term Borrowings in 2006, Docket No. 050630-GU, dated September 21, 2005, and is hereby incorporated by reference.

Pursuant to the current PIP, Chesapeake has issued 74,048 shares of common stock as of June 30, 2011 related to the 2006 to 2014 plan. Thus, there remains to be issued 325,952 shares as authorized by the Delaware Public Service Commission. The FPSC approved the issuance and sale of up to 100,000 shares of common stock for the PIP during 2011 by Order No. PSC-10-0744-FOF-GU, issued on December 27, 2010. Chesapeake now seeks FPSC authorization to issue up to 100,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's Performance Incentive Plan during 2012. The 100,000 shares should be adequate to cover any shares issued in 2012 pursuant to awards granted to executives and other key officers of the Company and its subsidiaries for 2011.

(c) Chesapeake's Dividend Reinvestment and Stock Purchase Plan ("DRP") was implemented on April 27, 1989. The DRP Administrator currently has the flexibility of purchasing shares of Chesapeake common stock on the open market, using Treasury stock or issuing new common stock. The gradual issuance of new common stock enables Chesapeake to balance the composition of its capital between common stock and long-term debt. As of June 30, 2011, the DRP had 1,806 stockholder participants.

A copy of the DRP as filed on Registration Statement Form S-3 with the Securities and Exchange Commission has been previously filed with the FPSC as Exhibit D of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 961194-GU, dated October 1, 1996, and is hereby incorporated by reference. On May 23, 1989, the Delaware Public Service Commission issued Order No. 3071 approving the issuance of up to 200,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's DRP. Please note that this Order by the Delaware Public Service Commission is "open ended" in the sense that there is no time limit by which the approved securities need to be issued. A copy of this Order has been previously filed with the FPSC within Exhibit J of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 931112-GU, dated November 17, 1993, and is hereby incorporated by reference. On December 20, 1995, the Delaware Public Service Commission issued Order No. 4097 approving the issuance of an additional 300,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's DRP. Please note that this Order by the Delaware Public Service Commission is also "open ended" in the sense that there is no time limit by which the approved securities need to be issued. A copy of this Order has been previously filed with the FPSC within Exhibit E of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 961194-GU, dated October 1, 1996, and is hereby incorporated by reference. On August 5, 2004, Chesapeake's Board of Directors approved 750,000 additional shares of common stock to be authorized and reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan, as well as several amendments to the terms of the Plan. The amended plan (a) allows for direct stock purchases by persons who at the times of purchase are not shareholders of the Company; (b) establishes the minimum investment amount for direct stock purchases by persons who are not shareholders of the Company; (c) fixes the minimum monthly and maximum annual optional cash investment limits for participating shareholders; (d) allows for direct debiting of shareholder-designated bank accounts for purchases; and (e) adds a provision to the Plan, whereby the Company, with the prior approval of the Board of Directors or under guidelines adopted by the Board of Directors, could on a case-by-case basis waive the maximum annual optional cash investment limit and accept investments in excess of that amount. On December 21, 2004 the Delaware Public Service Commission issued Order No. 6543, approving the issuance of an additional 750,000 shares of Chesapeake common stock for the purpose of administering Chesapeake's amended Dividend Reinvestment and Stock Purchase Plan. Please note that this Order by the Delaware Public Service Commission is "open ended" in the sense that there is no time limit by which the approved securities need to be issued. A copy of this Order has been previously filed with the FPSC within Exhibit C of the Consummation Report of Securities Issued by Chesapeake Utilities Corporation, Docket No. 030942-GU, dated March 22, 2005, and is hereby incorporated by reference. In addition, on December 16, 2008, Chesapeake filed a Registration Statement on Form S-3 with the Securities and Exchange Commission relating to the registration of 631,756 shares of the Company's common stock under the Dividend Reinvestment and Direct Stock Purchase Plan. The Registration Statement was declared effective by the Securities and Exchange Commission on January 5, 2009 and replaces the prior Registration Statement in place for the Plan that had previously expired. A copy of the Chesapeake Utilities Corporation Dividend Reinvestment and Direct Stock Purchase Plan as filed with the Securities and Exchange Commission on Registration Statement Form S-3 dated December 16, 2008 has previously been filed with the FPSC as Exhibit D of the Consummation Report of Securities Issued by Chesapeake Utilities Corporation, Docket No. 070640-GU, dated March 27, 2009, and is hereby incorporated by reference. Our current Registration Statement expires in January of 2012 and therefore we will be filing a Registration Statement with the Securities and Exchange Commission to continue the plan. A copy of the Form S-3 as filed will be provided with the upcoming Consummation Report.

Pursuant to the Orders above, Chesapeake has issued 703,657 new shares of common stock as of June 30, 2011. Thus, there remains to be issued 546,343 shares as authorized by the Delaware Public Service Commission. The FPSC approved the issuance and sale of up to 120,000 shares for the DRP during 2011 by Order No. PSC 10 0744 FOF GU, issued on December 27, 2010.

Chesapeake now seeks FPSC approval to issue up to 120,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's amended Dividend Reinvestment and Stock Purchase Plan during 2012.

(d) On April 4, 1989, Chesapeake issued $5,000,000 in 8.25% Convertible Debentures as part of a public offering. As of June 30, 2011, $1,221,000 remained outstanding with a conversion price of $17.01 per share. Hence, the maximum number of shares of common stock that could be issued upon conversion is 71,781. A true and correct copy of the Registration Statement on Form S-2 dated February 16, 1989, as filed with the Securities and Exchange Commission, has been previously filed with the FPSC as Exhibit I of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 931112-GU, dated November 17, 1993, and is hereby incorporated by reference.

The Debentures had a conversion premium greater than the offering price of the common stock issued, no mandatory sinking fund, and became callable after one year at a premium equal to the interest rate less 1%, declining 1/2% per year thereafter. There is an optional bondholder redemption feature, which allows any debenture holder to present any Debenture for redemption, at par, on the anniversary date of the issue, subject to annual limitations of $10,000 per debenture holder and $200,000 in the aggregate. These optional redemption rights began on April 1, 1991. In addition, subject to the annual limitations of $10,000 per debenture holder and $200,000 in the aggregate, Chesapeake will redeem the Debentures of deceased debenture holders within 60 days of notification. Such redemption of estate Debentures shall be made prior to other Debentures.

On February 14, 1989, the Delaware Public Service Commission issued Order No. 3040 approving the issuance of $5,000,000 in Convertible Debentures and, inherently, their potential conversion into Chesapeake common stock. Please note that this Order by the Delaware Public Service Commission is "open ended" in the sense that there is no time limit by which the approved securities need to be issued. A copy of this Order has been previously filed with the FPSC within Exhibit J of the Application for Approval of Issuance and Sale of Securities by Chesapeake Utilities Corporation, Docket No. 931112-GU, dated November 17, 1993, and is hereby incorporated by reference.

As of June 30, 2011, a cumulative $2,854,000 of the Convertible Debentures has been converted. The FPSC approved the issuance and sale of up to 84,000 new shares of Chesapeake common stock for the purpose of honoring conversion rights pursuant to the Company's Convertible Debentures during 2011, by Order No.PSC 10 0744 FOF GU, issued on December 27, 2010. Chesapeake now seeks FPSC authorization to issue up to 65,782 new shares of Chesapeake common stock for the purpose of honoring these conversion rights during 2012.

(e) On February 24, 2005, the Board adopted Chesapeake's Directors Stock Compensation Plan (DSCP) and on May 5, 2005, the DSCP received shareholder approval. Under the DSCP each non-employee director who is elected as a director or whose service as a director will continue after the date of the respective Annual Meeting will receive, as compensation for services during the ensuing year, an award of no more than 1,200 shares of the Company's common stock on the date of the Company's Annual Meeting. The DSCP enhances the Company's ability to attract, motivate and retain as non-employee directors persons of training, experience and ability and to encourage the highest level of non-employee director performance by providing such directors with a proprietary interest in the Company's growth and financial success. The DSCP expires on December 31, 2015.

On April 26, 2005, the Delaware Public Service Commission issued Order No. 6607 authorizing Chesapeake to issue up to 75,000 shares of common stock to administer the Company's DSCP.

A copy of the Application, and Order have been previously filed with the FPSC within Exhibit D, as well as the DSCP plan document within Exhibit F of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed the Limitation Placed on Short-Term Borrowings in 2006, Docket No. 050630-GU, dated September 21, 2005, and is hereby incorporated by reference. The FPSC approved the issuance of up to 15,000 shares of common stock for the DSCP during 2011 by Order No.PSC-10-0744-FOF-GU, issued on December 27, 2010. Pursuant to the DSCP, Chesapeake has issued a cumulative 51,889 new shares of common stock as of June 30, 2011. Thus, there remains to be issued 23,111 shares as previously authorized by the Delaware Public Service Commission.

Chesapeake now seeks FPSC authorization to issue up to 15,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's DSCP during 2012. The 15,000 shares should be adequate to cover any awards granted to non-employee directors of the Company in 2012.

(f) The Board adopted the Employee Stock Awards Plan (ESAP) on February 24, 2005; allowing the Company to grant stock awards to its top performing managers and employees of the year; and to have the flexibility to make other awards of stock to employees for exemplary performance. The ESAP received shareholder approval on May 5, 2005. The maximum number of shares that can be issued from the ESAP in any one year is 5,000. The ESAP expires on December 31, 2015.

On April 26, 2005, the Delaware Public Service Commission issued Order No. 6607 authorizing Chesapeake to issue up to 25,000 shares of common stock to administer the Company's ESAP.

A copy of the Application and Order have been previously filed with the FPSC within Exhibit D, as well as the ESAP document within Exhibit G of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed Limitation Placed on Short-Term Borrowings in 2006, Docket No. 050630-GU, dated September 21, 2005, and is hereby incorporated by reference. The FPSC approved the issuance of up to 5,000 shares of common stock for the ESAP during 2011 by Order No.PSC-10-0744-FOF-GU, issued on December 27, 2010. Pursuant to the ESAP, Chesapeake has issued a cumulative 1,650 shares of common stock as of June 30, 2011. Thus, there remains to be issued 23,350 shares as previously authorized by the Delaware Public Service Commission. Chesapeake now seeks FPSC authorization to issue up to 5,000 new shares of Chesapeake common stock for the purpose of administering Chesapeake's ESAP during 2012. The 5,000 shares should be adequate to cover any awards granted to managers and employees of the Company and its subsidiaries in 2012.

(g) Chesapeake now seeks FPSC approval to issue up to 500,000 shares of Chesapeake stock or an equity-linked instrument equivalent in value in 2012 to permanently finance Chesapeake's ongoing capital expenditure program. Financing for the Company's capital expenditure program is subject to continuous review and modification and is funded from short-term borrowings and cash provided by operating activities. The Company, in an effort to manage its capital structure, may, from time to time permanently finance through the issuance of common stock or an equity-linked instrument, as opposed to long-term debt. The FPSC approved the issuance of 800,000 shares of common stock for Chesapeake during 2011 by Order No. PSC-10-0744-FOF-GU, issued on December 27, 2010.

(h) Chesapeake seeks FPSC authorization to issue during 2012 up to $60,000,000 in secured and/or unsecured long-term debt with an estimated rate of interest of up to 300 basis points above U.S. Treasury rates (or extrapolated U.S. Treasury rates) with equivalent average life. The FPSC approved the issuance and sale of $60,000,000 in secured and/or unsecured long-term debt during 2011 by Order No. PSC-10-0744-FOF-GU, issued on December 27, 2010. The remaining proceeds from this debt issuance would be used for general corporate purposes including, but not limited to, working capital, retirement of short-term debt, retirement of long-term debt and capital improvements.

(i)Chesapeake seeks further FPSC authorization to issue during 2012 up to an additional 5,000,000 shares of common stock and an additional $60,000,000 in secured and/or unsecured long-term debt with an estimated rate of interest of up to 300 basis points above U.S. Treasury rates (or extrapolated U.S. Treasury rates) with equivalent average life. This additional stock and debt would be used to finance Chesapeake's ongoing acquisition program. Chesapeake expects to continue to search for growth opportunities through acquisitions, which fit its long-range plan to achieve the proper mix of business activities. Financing of acquisitions will depend upon the nature and extent of potential acquisitions as well as current market and economic conditions.

The FPSC approved the issuance and sale of 5,000,000 shares of common stock and $60,000,000 in secured and/or unsecured long-term debt for this purpose during 2011 by Order No. PSC 10 0744 FOF GU, issued on December 27, 2010.

(j)Chesapeake seeks FPSC authorization to issue up to 1,000,000 shares of Chesapeake preferred stock during 2012 for possible acquisitions, financing transactions, and other general corporate purposes, including potential distribution under the Company's Rights Agreement adopted by the Board of Directors on August 20, 1999. The Rights Agreement was subsequently modified and extended by the Board of Directors on September 12, 2008. Pursuant to the Board's actions, the expiration of the Rights was extended from August 20, 2009 to August 20, 2019 and the Exercise Price was increased per share from $54.56 to 105. The Rights Agreement approved by the Board of Directors is designed to protect the value of the outstanding common stock in the event of an unsolicited attempt by an acquirer to take over the Company in a manner or on terms not approved by the Board of Directors. The Rights Agreement is not intended to prevent a takeover of the Company at a fair price and should not interfere with any merger or business combination approved by the Board of Directors. Copies of the Forms 8-A and 8-K filed with the Securities and Exchange Commission in conjunction with the Rights Agreement have been previously filed with the FPSC as Exhibit D of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Exceed Limitation Placed on Short-Term Borrowings in 2000, Docket No. 991631-GU, dated October 20, 1999, and are hereby incorporated by reference. A copy of the Company's First Amendment to the Rights Agreement and the Form 8-K filed with the Securities and Exchange Commission in conjunction with the First Amendment to the Rights Agreement has been previously filed with the FPSC as Exhibit D of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt and to Enter into Agreements For Interest Rate Swap Products, Equity Products and Other Financial Derivatives and to Exceed Limitation Placed on Short-Term Borrowings in 2010, Docket No. 080635-GU, dated November 19, 2008, and are hereby incorporated by reference. As of June 30, 2011, zero (0) shares of Chesapeake preferred stock have been issued. The FPSC approved the issuance and sale of up to 1,000,000 shares of Chesapeake preferred stock for possible acquisitions, financing transactions, and other general corporate purposes, including potential distribution under the Company's Rights Agreement, during 2011 by Order No. PSC-10-0744-FOF-GU, issued on December 27, 2010.

(k) Chesapeake is also requesting authority during 2012 to enter into an agreement for financial derivatives including, but not limited to Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives on such terms as Chesapeake considers appropriate provided that the notional amount(s) for said Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives do not, in the aggregate, exceed the sum of $40,000,000. On July 9, 2002, the Delaware Public Service Commission issued Order No. 5989 approving the Company's application for approval of the issuance of certain long-term debt, and acknowledging that the Company was considering entering into, or utilizing Interest Rate Swap Products. While the Company does not consider such Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives to involve the actual issuance of securities within the ambit of Section 366.04 (1), Florida Statutes, in an abundance of caution, Chesapeake requests such authority to the extent the FPSC considers Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives subject to its jurisdiction. In the event that the FPSC does not consider Interest Rate Swap Products, Equity Products, and/or other Financial Derivatives to be jurisdictional, Chesapeake requests that that FPSC issue an Order acknowledging the Company's request and confirming the FPSC's absence of jurisdiction regarding these instruments.

A copy of this Order was filed as Exhibit C of the Application by Chesapeake Utilities Corporation for Authorization to Issue Common Stock, Preferred Stock and Secured and/or Unsecured Debt, and to Enter into Agreements for Interest Rate Swap Products, and to Exceed Limitation Placed on Short-Term Borrowings in 2004, Docket No. 030942-GU, and is hereby incorporated by reference.

7. <u>Purposes for which Securities are to be issued:</u>

The common stock, preferred stock and long-term debt authorized for issuance will be used for the purpose of administering Chesapeake's Retirement Savings Plan, Performance Incentive Plan, Dividend

Reinvestment and Stock Purchase Plan, Directors Stock Compensation Plan, Employee Stock Awards Plan, conversion of the Company's Convertible Debentures, financing of the Company's acquisition program and for other corporate purposes including, but not limited to the following: working capital; retirement of short-term debt; retirement of long-term debt; capital improvements; and potential distribution under the Rights Agreement. Chesapeake believes that Interest Rate Swap Products, Equity Products and other Financial Derivatives would provide Chesapeake with an additional opportunity to achieve lower cost funding of existing and prospective debt and equity placements, as well as enhanced flexibility to manage the Company's exposure to risk as market conditions permit. These are all for lawful objects within the corporate purposes of Chesapeake and compatible with the public interest and are reasonably necessary or appropriate for such purposes.

8. Counsel:

The legality of the common stock, preferred stock and debt issuances will be passed upon by William A. Denman, Esquire, Parkowski, Guerke and Swayze, P.A., 116 West Water Street, Dover, Delaware 19904, who will rely on Beth Keating, Esquire, Gunster, Yoakley & Stewart, Suite 618, 215 South Monroe Street, Tallahassee, Florida 32301, as to matters of Florida law.

9. Other Regulatory Agencies:

Under 26 Del. C Section 215 of the Delaware statutes, Chesapeake is regulated by the Delaware Public Service Commission and, therefore, must file a Prefiling Notice, a Notice, and an Application to obtain approval of the Delaware Commission before issuing new securities which mature more than one (1) year from the date of issuance. In addition, a Notice must be filed if

Chesapeake expects to incur short-term indebtedness, which exceeds ten percent of the Company's total capitalization. All necessary applications or registration statements have been or will be made as required and will be made a part of the final consummation report to the FPSC as required by Rule 25-8.009, Florida Administrative Code.

The address of the Delaware Commission is as follows:

Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building
Dover, Delaware 19904
Attention: William O'Brien, Executive Director

10. Control or ownership:

Applicant is not owned by any other company nor is Applicant a member of any holding company system.

11. Exhibits:

The following exhibits submitted with Applicant's Applications in Docket Nos. 931112-GU, 961194-GU, 981213-GU, 991631-GU, 030942-GU, 050630-GU, 070640-GU, 080635-GU, 09487-GU, and 100444-GU respectively, are incorporated in the instant Application by reference:

Docket No. 931112-GU

Exhibit I: Chesapeake Utilities Corporation Public Offering of Common Stock and Convertible Debentures as filed with the Securities and Exchange Commission on Registration Statement Form S-2 dated February 16, 1989.

Exhibit J: Delaware Public Service Commission Order No. 3425 dated June 23, 1992 for the Issuance of Common Stock pursuant to Chesapeake Utilities Corporation Retirement Savings Plan (100,000 shares);

Delaware Public Service Commission Order No. 3425 dated June 23, 1992 for Issuance of Common Stock pursuant to

Chesapeake Utilities Corporation Performance Incentive Plan (200,000 shares);

Delaware Public Service Commission Order No. 3071 dated May 23, 1989 for the Issuance of Common Stock pursuant to Chesapeake Utilities Corporation Dividend Reinvestment and Direct Stock Purchase Plan (200,000 shares);

and

Delaware Public Service Commission Order No. 3040 dated February 14, 1989 authorizing $5,000,000 for Chesapeake Utilities Corporation 8.25% Convertible Debentures.

Docket No. 961194-GU

Exhibit D: Chesapeake Utilities Corporation Dividend Reinvestment and Stock Purchase Plan as filed with the Securities and Exchange Commission on Registration Statement Form S-3 dated December 1, 1995.

Exhibit E: Delaware Public Service Commission Order No. 4097 dated December 20, 1995, for the issuance of 300,000 shares pursuant to Chesapeake Utilities Corporation's Dividend Reinvestment and Stock Purchase Plan.

Docket No. 981213-GU

Exhibit C: Chesapeake Utilities Corporation Amended Performance Incentive Plan.

Docket No. 991631-GU

Exhibit C: Delaware Public Service Commission Order No. 5165 dated July 13, 1999 for the Issuance of Common Stock pursuant to Chesapeake Utilities Corporation Retirement Savings Plan (100,000 shares) and Chesapeake Utilities Corporation Performance Incentive Plan (200,000 shares).

Exhibit D: Securities and Exchange Commission Form 8-A For Registration of Certain Classes of Securities Pursuant to Section 12(B) or 12(G) of the Securities Exchange Act of 1934 Securities and Exchange Commission Form 8-K Current Report.

Exhibit E: Delaware Public Service Commission Order No. 5609 dated December 19, 2000 pursuant to Chesapeake Utilities Corporation Retirement Savings Plan (300,000 shares) (as filed with the FPSC Consummation Report of Securities Issued by Chesapeake Utilities Corporation on March 29, 2001).

Docket No. 030942-GU

Exhibit C: Delaware Public Service Commission Order No. 6543 dated December 21, 2004 pursuant to Chesapeake Utilities Corporation Dividend Reinvestment and Direct Stock Purchase Plan (750,000 shares) (as filed with the FPSC 2004 Consummation Report of Securities Issued by Chesapeake Utilities Corporation on March 22, 2005).

Exhibit C: Delaware Public Service Commission Order No. 5989 dated July 9, 2002 authorizing the issuance of long-term debt.

Docket No. 050630-GU

Exhibit D: Delaware Public Service Commission Application and Order No. 6607 dated April 26, 2005 for the Issuance of up to 500,000 shares of Chesapeake Utilities Corporation Common Stock for administering Chesapeake Utilities Corporation Performance Incentive Plan, Directors Stock Compensation Plan and Employee Stock Awards Plan.

Exhibit E: A copy of Chesapeake Utilities Corporation Performance Incentive Plan document (400,000 shares).

Exhibit F: A copy of Chesapeake Utilities Corporation Directors Stock Compensation Plan document (75,000 shares).

Exhibit G: A copy of Chesapeake Utilities Corporation's Employee Stock Awards Plan document (25,000 shares).

Docket No. 070640-GU

Exhibit C: Retirement Savings Plan Document filed with the Internal Revenue Service dated January 30, 2007, effective January 1, 2006.

Exhibit D: Chesapeake Utilities Corporation Public Offering of Common Stock as filed with the Securities and Exchange Commission on Registration Statement Form S-3 dated July 5, 2006.

Exhibit E: Chesapeake Utilities Corporation Prospectus Supplement as filed with the Securities and Exchange Commission pursuant to Rule 424(b)(5) dated November 9, 2006.

Exhibit F: Delaware Public Service Commission Application and Order No. 7065 dated October 16, 2006 for the issuance of up to $40,000,000 in common stock and/or debt securities over a three-year financing period pursuant to Chesapeake Utilities Corporation's Shelf Registration Statement.

Docket No. 080635-GU

Exhibit C: Delaware Public Service Commission Application dated September 29, 2008, requesting approval for the issuance of up to $10,000,000 of Chesapeake Utilities Corporation unsecured long-term debt securities.

Delaware Public Service Commission Order No. 7464 dated October 23, 2008, for the Issuance of up to $10,000,000 of Chesapeake Utilities Corporation 5.93% Unsecured Senior Notes (as filed with the FPSC Consummation Report of Securities Issued by Chesapeake Utilities Corporation on March 27, 2009).

Exhibit D: Chesapeake Utilities Corporation First Amendment to Rights Agreement and Securities and Exchange Commission Form 8-K pursuant to Chesapeake Utilities Corporation First Amendment to Rights Agreement

Chesapeake Utilities Corporation Dividend Reinvestment and Direct Stock Purchase Plan as filed with the Securities and Exchange Commission on Registration Statement Form S-3 dated December 16, 2008 (as filed with the FPSC Consummation Report of Securities Issued by Chesapeake Utilities Corporation on March 27, 2009).

Docket No. 09487-GU

Exhibit B: Sources and Uses of Funds Statement and Construction Budget.

Exhibit C: $30,000,000 Note Agreement for Chesapeake Utilities Corporation 5.93% Unsecured Senior Notes.

Exhibit D: Delaware Public Service Commission Application dated May 18, 2009, requesting approval for the issuance of up to 2.6 million shares of Chesapeake Utilities Corporation common stock in conjunction with the FPU merger.

Exhibit E: Delaware Public Service Commission Order No. 7951 dated June 11, 2009 for the issuance of up to 2.6 million shares of Chesapeake Utilities Corporation common stock in conjunction with the FPU merger

Exhibit F: Chesapeake Utilities Corporation Joint Proxy Statement/Prospectus as filed with the Securities and Exchange Commission on Registration Statement Form S-4 pursuant to Rule 424(b)(5) dated September 15, 2009.

Docket No. 100444-GU

Exhibit A: Exhibit A consists of the following attachments:

A (1) Chesapeake Utilities Corporation Annual Report on Form 10-K for the year ended December 31, 2009.

A (2) Chesapeake Utilities Corporation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

Exhibit B: Amended and Restated Certificate of Incorporation dated July 22, 2010.

Exhibit C: Delaware Public Service Commission issued Order No. 7769 dated May 4, 2010 approving the issuance of an additional 600,000 new shares of Chesapeake common stock for the purpose of administering the RSP.

Exhibit D: Delaware Public Service Commission issued Order No. 7787 dated June 30, 2010 approving the issuance of $36,000,000 of unsecured senior notes to refinance FPU First Mortgage Bonds acquired in the merger.

Filed herewith:

Exhibit A: Exhibit A consists of the following attachments:

A (1) Chesapeake Utilities Corporation Annual Report on Form 10-K for the year ended December 31, 2010.

A (2) Chesapeake Utilities Corporation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011.

12. Constitutionality of Statute:

Chesapeake has taken the position that the statutory requirement of FPSC approval of the issuance and sale of securities by a public utility, under Section 366.04 (1), Florida Statutes, as applied to Chesapeake, a Delaware corporation engaged in interstate commerce, is unconstitutional, in that it creates an unreasonable burden on interstate commerce. Support for this position is set out in Chesapeake's Petition for declaratory statement disclaiming jurisdiction, as filed in FPSC Docket No. 930705-GU. By FPSC Order No. PSC-93-1548-FOF-GU, issued on October 21, 1993, the FPSC denied the Petition for declaratory statement, while approving the alternative Application for approval of the issuance of up to 100,000 new shares of common stock for the purpose of administering a Retirement Savings Plan. The FPSC found that "the facial constitutionality of a statute cannot be decided in an administrative proceeding," and that since the stock issuance was approved, "the question of constitutionality appears to be academic at this time."

Chesapeake continues to maintain that the assertion of jurisdiction by the FPSC over its securities unconstitutionally burdens interstate commerce, particularly where the Public Service Commission of the State of Delaware has approved their issuance and sale, and/or where the securities do not create a lien or encumbrance on assets of Chesapeake's public utility operations in the State of Florida.

Florida law provides for severe penalties for any willful violation of a statute administered by the FPSC or any of its rules or orders, Secs. 350.127 (1) and 366.095, Florida Statutes. Accordingly, Chesapeake believes it must submit to FPSC jurisdiction over its securities if it is to avoid assessment of such penalties and to otherwise remain in good standing before the FPSC. It therefore files the instant Application, under protest, and without waiver of its position regarding the unconstitutionality of the statute.

PRAYER FOR RELIEF

Based on the foregoing, Chesapeake Utilities Corporation requests that the FPSC issue an Order authorizing it in 2012 to issue up to 5,875,782 shares of common stock, up to 1,000,000 shares of preferred stock, and up to $120,000,000 of secured and/or unsecured debt, and authorizing it to enter into agreements up to $40,000,000 in Interest Rate Swap Products, Equity Products and other Financial Derivatives, and to exceed the limitation placed on short-term borrowings by Section 366.04, Florida Statutes, so as to issue up to $100,000,000 in short-term obligations.

Respectfully submitted,

Date: November 2, 2011

Beth Keating

Beth Keating, Esquire
Gunster, Yoakley & Stewart, P.A.
Suite 618
215 South Monroe Street
Tallahassee, Florida 32301
(850) 521-1706

Attorneys for
Chesapeake Utilities Corporation

STATE OF DELAWARE *

*

COUNTY OF KENT * SS

BE IT REMEMBERED that on this the day of November 2, 2011 , personally appeared before me, a Notary Public for the State of Delaware, Beth W. Cooper, who being by me duly sworn, did depose and say that she is Senior Vice President, Chief Financial Officer, Treasurer and Corporate Secretary of Chesapeake Utilities Corporation, a Delaware corporation, and that insofar as the Application of Chesapeake Utilities Corporation states facts, and insofar as those facts are within her personal knowledge, they are true; and insofar as those facts that are not within her personal knowledge, she believes them to be true, that the exhibits accompanying this Application and attached hereto are true and correct copies of the originals of the aforesaid exhibits, and that she has executed this Application on behalf of the Company and pursuant to the authorization of its Board of Directors.

Beth W. Cooper

Beth W. Cooper
Senior Vice President, Chief Financial Officer,
Treasurer and Corporate Secretary

SWORN TO AND SUBSCRIBED before me the day and year first above written.

Patricia L. Connors

PATRICIA L. CONNORS
NOTARY PUBLIC
MY COMMISSION EXPIRES FEB 19TH 2012
STATE OF DELAWARE

Notary Public
My Commission Expires: 2/19/12

EXHIBITS

A (1)	Chesapeake Utilities Corporation Annual Report on Form 10-K for the year ended December 31, 2010.
A (2)	Chesapeake Utilities Corporation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011.
B	Chesapeake Utilities Corporation Retirement Savings Plan and Trust Amended and Restated Effective as of January 1, 2011.

Exhibit A(1)

ANNUAL REPORT
FORM 10-K

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, 2010 Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

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

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including zip code)

302-734-6799
(Registrant's telephone number, including area code)

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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ]. No [X].

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ] Smaller Reporting Company [ ]

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

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2010, 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 $297.6 million.

As of February 28, 2011, 9,529,333 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2011 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

CHESAPEAKE UTILITIES CORPORATION

FORM 10-K

YEAR ENDED DECEMBER 31, 2010

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 wholly-owned subsidiary of Chesapeake, effective October 28, 2009
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's 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
IASB	International Accounting Standards Board
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

Accounting Standards Related

ASC	FASB Accounting Standards Codification ™
ASU	FASB Accounting Standards Update
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
FASB	Financial Accounting Standards Board

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
Columbia	Columbia Gas Transmission, LLC
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per Day
FCG	Florida City Gas
FGT	Florida Gas Transmission Company
FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf	Columbia Gulf Transmission Company
Gulf Power	Gulf Power Company
Gulfstream	Gulfstream Natural Gas System, LLC
HDD	Heating Degree-Days
IGC	Indiantown Gas Company
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MWH	Megawatt Hour
NYSE	New York Stock Exchange
PIP	Performance Incentive Plan
RAP	Remedial Action Plan
S&P 500 Index	Standard & Poor's 500 Index
Sanford Group	FPU and Other Responsible Parties involved with the Sanford Environmental Site
TETLP	Texas Eastern Transmission, LP
Transco	Transcontinental Gas Pipe Line Company, LLC

PART I

References in this document to "Chesapeake," "the Company," "we," "us" and "our" mean Chesapeake Utilities Corporation 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 conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks and uncertainties. In addition to the risk factors described under Item 1A "Risk Factors," the following important factors, among others, could cause actual future results to differ materially from those expressed in the forward-looking statements:

- state and federal legislative and regulatory initiatives 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, other hostilities or other external factors over which we have no control;
- changes in environmental and other laws and regulations to which we are subject;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- declines in the market prices of equity securities and resultant cash funding requirements for our defined benefit pension plans;
- the creditworthiness of counterparties with which we are engaged in transactions;
- growth in opportunities for our business units;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to manage and maintain key customer relationships;
- the ability to maintain key supply sources;
- the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;

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

ITEM 1. BUSINESS.

(a) Overview

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

(b) Operating Segments

We are composed of three operating segments:

- *Regulated Energy.* The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and 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 for 2010 and net property, plant and equipment as of December 31, 2010:

(in thousands)	Operating Income		Net Property, Plant & Equipment	
Regulated Energy	$ 43,509	84%	$ 414,622	90%
Unregulated Energy	7,908	15%	35,658	8%
Other	513	1%	12,477	2%
Total	$ 51,930	100%	$ 462,757	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

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

Our Delaware and Maryland natural gas distribution divisions serve 52,686 residential and commercial customers and 177 industrial customers in central and southern Delaware and Maryland's Eastern Shore. For the year ended December 31, 2010, operating revenues and deliveries by customer class for our Delaware and Maryland distribution divisions were as follows:

	Operating Revenues (in thousands)			Deliveries (Mcfs)	
Residential	$	46,041	57%	2,881,073	35%
Commercial		27,896	34%	2,145,143	26%
Industrial		3,766	5%	3,020,907	36%
Subtotal		77,703	96%	8,047,123	97%
Interruptible		655	1%	232,653	3%
Other [1]		2,507	3%	-	-
Total	$	80,865	100%	8,279,776	100%

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

Our Florida natural gas distribution operations consist of Chesapeake's Florida division and FPU's natural gas operation, which was acquired in the merger with FPU in October 2009. In August 2010, FPU added a new division through the purchase of the natural gas operating assets of Indiantown Gas Company ("IGC"). On a combined basis, our Florida natural gas distribution operations serve 61,053 residential customers and 6,314 commercial and industrial customers in 20 counties in Florida. For the year ended December 31, 2010, operating revenues and deliveries by customer class for our Florida natural gas distribution operations were as follows:

	Operating Revenues (in thousands)			Deliveries (Mcfs)	
Residential	$	27,742	35%	1,716,934	8%
Commercial		39,006	48%	4,451,414	20%
Industrial		13,043	16%	15,582,234	72%
Other		607	1%	12,723	-
Total	$	80,398	100%	21,763,305	100%

[1] Operating revenues from "other" include unbilled revenue, conservation revenue, fees for billing services provided to third parties and other miscellaneous charges.

Electric Distribution

Our Florida electric distribution operation, which was acquired in the FPU merger, distributes electricity to 30,966 customers in four counties in northeast and northwest Florida. For the year ended December 31, 2010, operating revenues and deliveries by customer class for the FPU electric distribution operation were as follows:

		Operating Revenues (in thousands)		Deliveries (MWHs)	
Residential	$	51,498	55%	347,040	47%
Commercial		45,332	48%	332,322	45%
Industrial		7,705	8%	66,580	9%
Subtotal		104,535	111%	745,942	101%
Other [1]		(10,452)	(11%)	(6,286)	(1%)
Total	$	94,083	100%	739,656	100%

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

Natural Gas Transmission

ESNG operates a 396-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, 2010, *operating revenues and deliveries by customer class for ESNG were as follows:*

		Operating Revenues (in thousands)		Deliveries (Mcfs)	
Local distribution companies	$	20,441	76%	10,848,108	62%
Industrial		4,864	18%	4,794,442	27%
Commercial		1,571	6%	1,962,890	11%
Other [1]		41	0%	-	-
Subtotal		26,917	100%	17,605,440	100%
Less: affiliated local distribution companies		(12,903)	(48%)	(5,853,083)	(33%)
Total non-affiliated	$	14,014	52%	11,752,357	67%

[1] Operating revenues from "other" sources are from rental of gas properties.

PIPECO currently provides natural gas transportation services to a customer for a period of 20 years beginning in January 2009 at a fixed monthly charge, through an eight-mile pipeline located in Suwanee County, Florida, which PIPECO owns. For the year ended December 31, 2010, 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- Delaware and Maryland

Our Delaware and Maryland natural gas distribution divisions have both firm and interruptible transportation service contracts with five interstate "open access" pipeline companies, including the 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 Company LLC ("Transco"), Columbia Gas Transmission LLC ("Columbia"), Columbia Gulf Transmission Company ("Gulf") and Texas Eastern Transmission, LP ("TETLP"). The Transco, Columbia and TETLP pipelines are directly interconnected with the 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.

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP in conjunction with TETLP's new expansion project. Upon satisfaction of certain conditions provided in the Precedent Agreement, the Delaware and Maryland divisions will execute two firm transportation service contracts, one for our Delaware division for 28,986 Mcfs per day and one for our Maryland division for 9,662 Mcfs per day, to be effective on the service commencement date of the project, which is currently projected to occur in November 2012. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide us with an additional direct interconnection with ESNG's transmission system and access to new sources of natural gas supplies from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth. In December 2010, ESNG completed its mainline extension to interconnect with the TETLP pipeline. Until TETLP's expansion project is completed, our Delaware and Maryland divisions expect to utilize currently available capacity on a portion of TETLP's existing pipeline. For the 2010 and 2011 winter season, our Delaware and Maryland divisions have contracted for 14,493 Mcfs per day and 4,831 Mcfs per day, respectively, from TETLP.

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 spot market purchases.

The following table shows the firm transportation 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 transportation 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 2012 and 2028
Columbia	17,836	7,946	Various dates between 2011 and 2020
Gulf	850	-	Expires in 2014
TETLP	14,493	-	Expires in 2012
ESNG	64,602	4,006	Various dates between 2011 and 2027

Maryland

Pipeline	Firm transportation capacity maximum peak-day daily deliverability (Mcfs)	Firm storage capacity maximum peak-day daily withdrawal (Mcfs)	Expiration
Transco	5,921	2,909	Various dates between 2012 and 2013
Columbia	6,473	3,539	Various dates between 2011 and 2018
Gulf	570	-	Expires in 2014
TETLP	4,831	-	Expires in 2012
ESNG	21,380	2,228	Various dates between 2011 and 2027

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.

Natural Gas Distribution- Florida

Chesapeake's Florida natural gas distribution division has firm transportation service contracts with Florida Gas Transmission Company ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream"). Pursuant to a program approved by the Florida Public Service Commission ("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, 2012, for daily firm transportation capacity of 17,175 Mcfs for the months of November through April, capacity of 14,695 Mcfs for the months of May through September, and 16,143 Mcfs for October; and (b) a contract for daily firm transportation capacity of 974 Mcfs daily, which expires in 2015. Chesapeake's contract with Gulfstream is for daily firm transportation capacity of 9,737 Mcfs and expires in 2022.

FPU has the following firm transportation contracts with FGT:

(a) two contracts expiring in July 2020 for daily firm transportation capacity of:

	Daily Firm Transportation Capacity (*in Mcfs*)
January - March	28,647
April	24,156
May - September	9,681
October	10,210
November - December	28,647

(b) one contract expiring in February 2015 for daily firm transportation capacity of:

	Daily Firm Transportation Capacity (*in Mcfs*)
January - April	10,286
May - October	4,360
November - December	10,286

(c) one contract for daily firm transportation capacity of 1,774 Mcfs with various partial expiration dates between 2016 and 2023.

FPU also has a firm transportation contract with Florida City Gas ("FCG"), expiring in 2013, which provides daily firm transportation capacity of 292 Mcfs on its Pioneer Pipeline, and a firm transportation contract with IGC, expiring in 2016, which provides daily firm transportation capacity of 487 Mcfs on its distribution system.

FPU uses gas marketers and producers to procure all of 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 services.

Electric Distribution

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

Competition

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

Rates and Regulation

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 natural gas and electric supply and transportation costs and normally allow full recovery of such costs. Adjustments under these mechanisms, which are limited to such costs, require periodic filings and hearings with the state 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 transportation and storage services. PIPECO is subject to regulation by the Florida PSC.

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

Regulated Business	Regulatory Jurisdiction	Effective Date of the Currrent Rates	Allowed Return
Chesapeake - Delaware Division	Delaware PSC	9/3/2008	10.25% (1)
Chesapeake - Maryland Division	Maryland PSC	12/1/2007	10.75% (1)
Chesapeake - Florida Division	Florida PSC	1/14/2010	10.80% (1)
FPU - Natural Gas	Florida PSC	1/14/2010 (3)	10.85% (1)
FPU - 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.

On December 30, 2010, ESNG submitted a base rate filing to the FERC. 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."

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.

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

(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 2,486 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, 2010, PESCO's operating revenues and deliveries were as follows:

State	Operating Revenues (in thousands)			Deliveries (Mcfs)	
Florida	$	47,441	86%	8,236,014	84%
Delmarva		8,006	14%	1,538,895	16%
Total	$	55,447	100%	9,774,909	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 2011. PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements prior to the end of the term of the existing contracts.

Propane Distribution

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

Sharp, our propane distribution subsidiary, serves 34,243 customers throughout Delaware, the Eastern Shore of Maryland and Virginia, and southeastern Pennsylvania. Our Florida propane distribution subsidiary provides propane distribution services to 13,857 customers in parts of Florida. For the year ended December 31, 2010, operating revenues and total gallons sold by our Delmarva and Florida propane distribution operations were as follows:

State	Operating Revenues (in thousands)			Total Gallons Sold (in thousands)	
Delmarva	$	68,558	79%	32,617	82%
Florida		18,725	21%	6,995	18%
Total	$	87,283	100%	39,612	100%

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 propane wholesale price volatility and supply levels. In 2010, Xeron had operating revenues totaling approximately $1.8 million, net of the associated cost of propane sold. For further discussion of 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 incorporated in Delaware.

(c) Additional information about the Business

(i) Capital Budget

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

(ii) Employees

As of December 31, 2010, we had a total of 734 employees, 160 of whom are union employees represented by three labor unions: the International Brotherhood of Electrical Workers, the International Chemical Workers Union and United Food and Commercial Workers Union, all of whose collective bargaining agreements expire in 2013.

(iii) Financial Information about Geographic Areas

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

(d) Available Information

As a public company, we file annual, quarterly and other reports, as well as our annual proxy statement and other information, with the Securities and Exchange Commission ("SEC"). The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549-5546; the public may obtain information 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.

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 Boulevard, Dover, DE 19904.

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

Our Chief Executive Officer certified to the NYSE on June 3, 2010 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. Although we have achieved significant synergies, cost savings and operating efficiencies since the merger, there can be no assurance that these benefits will be sustained in the future, or additional benefits will be achieved in the future. Failure to sustain these benefits or achieve additional benefits in the future will adversely affect our expected future performance.

We are currently in discussions with the Office of Public Counsel and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings level as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. If we fail to obtain the necessary approval to earn a return on the purchase premium and merger-related costs and treat the amortization as allowable operating costs, we may be required to expense the amortization of these assets without recovery, which will adversely affect our financial performance for the related periods. We may also be required to pass on to ratepayers, some, or all of the increased earnings generated from cost savings, resulting from the merger.

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. Specifically, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flows from our operations. Currently, $40 million of the total $100 million of short-term lines of credit utilized to satisfy our short-term financing requirements are discretionary, uncommitted lines of credit. We utilize discretionary lines of credit to reduce the cost associated with these short-term financing requirements. We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access the capital markets when required. However, if we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

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

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.

A continued downturn in the economies of the regions in which we operate, 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. These economic conditions have slowed the growth in our customer base and cash flows. 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.

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

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

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

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for regulated operations and closely monitor the returns of our unregulated operations. There can be no assurance that we will be able to obtain adequate and timely rate increases to offset the effects of inflation. To compensate for fluctuations in propane gas prices, we adjust our propane selling prices to the extent allowed by the market. There can be no assurance, however, that we will be able to increase propane sales prices sufficiently to compensate fully for such fluctuations in the cost of propane gas to us.

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

Our natural gas marketing and propane wholesale marketing operations are subject to market risks beyond their control, including market liquidity and commodity price volatility. Although we maintain 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 our Company declines, then the cost of credit available to these subsidiaries could increase. If credit is not available, or if credit is more costly, our results of operations, cash flows and financial condition may be adversely affected.

Current market conditions have had an adverse impact on the return on plan assets for our pension plans, which may require significant additional funding and adversely affect our 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 have fluctuated significantly since 2008. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values 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. We began the process of integrating operations, both geographically and organizationally, immediately after the merger and this process is still on-going today. While significant progress has been made in integration, we continue to combine and enhance various systems, facilities and personnel deployment. Throughout the integration process, we are subject to employee workforce factors, including loss of key employees, availability of qualified personnel, collective bargaining agreements with unions and work stoppages that could affect our business and financial condition. Continued integration efforts may divert management's focus and resources from other strategic opportunities. The diversion of management's attention and any delays or difficulties encountered in connection with continued integration activities 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 seasonal than natural gas and propane sales as electricity is used for both heating and cooling in our service areas, are also affected by variations in general weather conditions and 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 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, FPU's natural gas is transported primarily 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.

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 and electricity as energy sources and consequently have an adverse effect on our operating cash flows.

Propane. Propane costs are subject to volatile changes as a result of product supply or other market conditions, including weather and economic and political factors affecting crude oil and natural gas supply or pricing. 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.

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

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

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

Our use of derivative instruments may adversely affect our results of operations.
Fluctuating commodity prices may affect our earnings and financing costs because our propane distribution and wholesale marketing operations use derivative instruments, including forwards, futures, swaps and puts, to hedge price risk. In addition, we have utilized in the past, and may decide, after further evaluation, to continue to utilize derivative instruments to hedge price risk. While we have 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 energy sources. Slowdowns in these markets may adversely affect our gross margin in our regulated energy or propane distribution businesses, earnings and cash flows.

Our businesses are capital intensive, and the costs of capital projects may be significant.
Our businesses are capital intensive and require significant investments in internal infrastructure projects. Our results of operations and financial condition could be adversely affected if we do not pursue or are unable to manage such capital projects effectively or if full recovery of such capital costs is not permitted in future regulatory proceedings.

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. 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. 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.

Regulatory and Legal Risks

Regulation of our 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. When our earnings from the regulated utilities exceed the authorized rate of return, these commissions may require us to refund the excess earnings or reduce our rates charged to customers in the future.

We are required to detail known benefits, synergies, cost savings and cost increases resulting from the FPU merger and present the information in the "come-back" filing to the Florida PSC by April 29, 2011 (within 18 months of the FPU merger). We also intend to seek for the recovery of the purchase premium and merger-related costs from the FPU merger. We are currently in discussions with the Office of Public Counsel of Florida regarding the "come-back" filing and the recovery of the purchase premium and merger-related costs. The outcome of such discussions or the ultimate outcome of the "come-back" filing, are unknown at this time.

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 $51 million covering general liabilities of our 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 and the purchase of the operating assets from IGC resulted in approximately $34.9 million in purchase premium which is currently recorded as goodwill. We intend to seek regulatory approval to include the purchase premium and approximately $2.2 million in merger-related costs 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 demonstrate the benefits of the merger, the regulatory environment in Florida and the 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.

We may face certain regulatory and financial risks related to climate change legislation.

A number of proposals to limit greenhouse gas emissions, measured in carbon dioxide equivalent units, are pending, or at least being considered, at regional, federal and international levels. These proposals would require us to measure and potentially limit greenhouse gas emissions from our energy operations and our customers or purchase allowances for such emissions. While we cannot predict with certainty the extent of these limitations or when they will become effective, these actions could:

- increase our costs related to operations, energy efficiency activities and compliance;
- affect the demand for natural gas, electricity and propane; and
- increase the prices we charge our energy customers.

The occurrence of any such legislation could adversely affect our results of operations, financial condition and cash flows. If our regulated energy operations 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 our results of operations, financial condition and cash flows.

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

A number of proposals to implement increased oversight over pipeline operations and increased investment in facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities are pending at the federal level. Additional operating expenses and capital expenditures may be necessary to remain in compliance with the increased federal oversight resulting from such proposals. While we cannot predict with certainty the extent of these expenses and expenditures or when they will become effective, the adoption of such legislation could adversely affect our results of operations, financial conditions and cash flows. If our regulated natural gas operations 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 our results of operations, financial condition and cash flows.

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.

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

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

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

We have participated in the investigation, assessment or remediation of environmental matters with respect to certain of our properties and we believe our 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.

The site with the most potential exposure is the former West Palm Beach MGP. In November 2010, we presented a new proposed strategy with an aggressive remedial action plan to expedite remediation of this site, and the Florida Department of Environmental Protection (the "FDEP") agreed with the proposal to implement a phased approach. In February 2011, FDEP approved the interim Remedial Action Plan ("RAP") for the east parcel of this site, contingent upon certain conditions, and we are currently implementing the plan. Our current estimate of total remediation costs and expenses for the West Palm Beach site based on the most recently proposed remedial action plan is between $5.1 million and $13.3 million. This estimate does not include any costs associated with relocation of our operations from the site, which is necessary to implement the remedial action, and any potential costs associated with re-development of the properties. Actual costs may also be higher or lower than the range of current estimate based upon the final remedy required by FDEP.

As of December 31, 2010, we had recorded $358,000 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 $1.3 million in assets for future recovery of environmental costs to be received from our customers through our approved rates. As of December 31, 2010, we had recorded approximately $11.6 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, 2010, 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 $11.6 million recorded as environmental liabilities related to FPU's MGP sites in Florida as of December 31, 2010, we have recovered approximately $7.8 million of environmental costs from insurance and customers through rates, and have recorded approximately $6.2 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 previously described.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

(a) General

We own offices and operate facilities in the following locations: Pocomoke, Salisbury, Cambridge and Princess Anne, Maryland; Dover, Seaford, Laurel and Georgetown, Delaware; Lecanto, Virginia; and West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill, Fernandina Beach and Winter Haven, Florida. We rent office space in Dover, Ocean View, and South Bethany, Delaware; 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 1,127 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 2,451 miles of natural gas distribution mains (and related equipment). In addition, we have adequate gate stations to handle receipt of the gas in each of the distribution systems. We also own facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

(c) Natural Gas Transmission

ESNG owns and operates approximately 396 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Pennsylvania; Daleville, Pennsylvania; Honey Brook, 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 1,128 miles of electric distribution line located in northeast and northwest Florida.

(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 our Company. Our Florida-based propane distribution operation owns 24 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: West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill and Fernandina Beach, Florida. FPU's natural gas distribution operation owns 1,659 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 1,128 miles of electric distribution line located in northeast and northwest Florida. FPU's propane distribution operation owns 24 bulk propane storage facilities with a total capacity of 642,000 gallons located in south and central Florida.

ITEM 3. LEGAL PROCEEDINGS.

(a) General

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

(b) Environmental

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

ITEM 4. REMOVED AND RESERVED

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT.

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

Name	Age	Position
Michael P. McMasters	52	President and Chief Executive Officer
Beth W. Cooper	44	Senior Vice President and Chief Financial Officer
Stephen C. Thompson	50	Senior Vice President and President, ESNG
Joseph Cummiskey	39	Vice President and President, PESCO
Elaine B. Bittner	41	Vice President of Strategic Development

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

Beth W. Cooper was appointed as Senior Vice President and Chief Financial Officer in September 2008 in addition to her duties as Treasurer and Corporate Secretary. Prior to this appointment, Ms. Cooper served as Vice President and Corporate Secretary 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.

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

PART II

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

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

Our common stock is listed on the NYSE under the symbol "CPK." The high, low and closing prices of our common stock and dividends declared per share for each calendar quarter during the years 2010 and 2009 were as follows:

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2010					
	March 31	**$ 32.25**	**$ 28.22**	**$ 29.80**	**$ 0.315**
	June 30	**32.20**	**28.01**	**31.40**	**0.330**
	September 30	**36.93**	**30.24**	**36.22**	**0.330**
	December 31	**42.20**	**35.00**	**41.52**	**0.330**
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

Holders

At December 31, 2010, there were 2,482 holders of record of Chesapeake common stock.

Dividends
We have paid a cash dividend to common stock shareholders for 50 consecutive years. Dividends are payable at the discretion of our Board of Directors. Future payment of dividends, and the amount of these dividends, will depend on our financial condition, results of operations, capital requirements, and other factors. We declared quarterly cash dividends on our common stock in 2010 and 2009, totaling $1.305 per share and $1.250 per share, respectively.

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, 2010, Chesapeake's cumulative consolidated net income base was $128.9 million, offset by Restricted Payments of $76.2 million, leaving $52.7 million of cumulative net income free of restrictions.

Each series of FPU's first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which 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. As of December 31, 2010, FPU had a cumulative net income base of $65.9 million, offset by restricted payments of $37.6 million, leaving $28.3 million of cumulative net income of FPU free of restrictions based on this covenant.

Recent Sales of Unregistered Securities
No securities were sold during the year 2010 that were not registered under the Securities Act of 1933, as amended.

(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, 2010.

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, 2010 through October 31, 2010 (1)	258	$37.58	-	-
November 1, 2010 through November 30, 2010	-	-	-	-
December 1, 2010 through December 31, 2010	-	-	-	-
Total	258	$37.58	-	-

(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, 258 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.

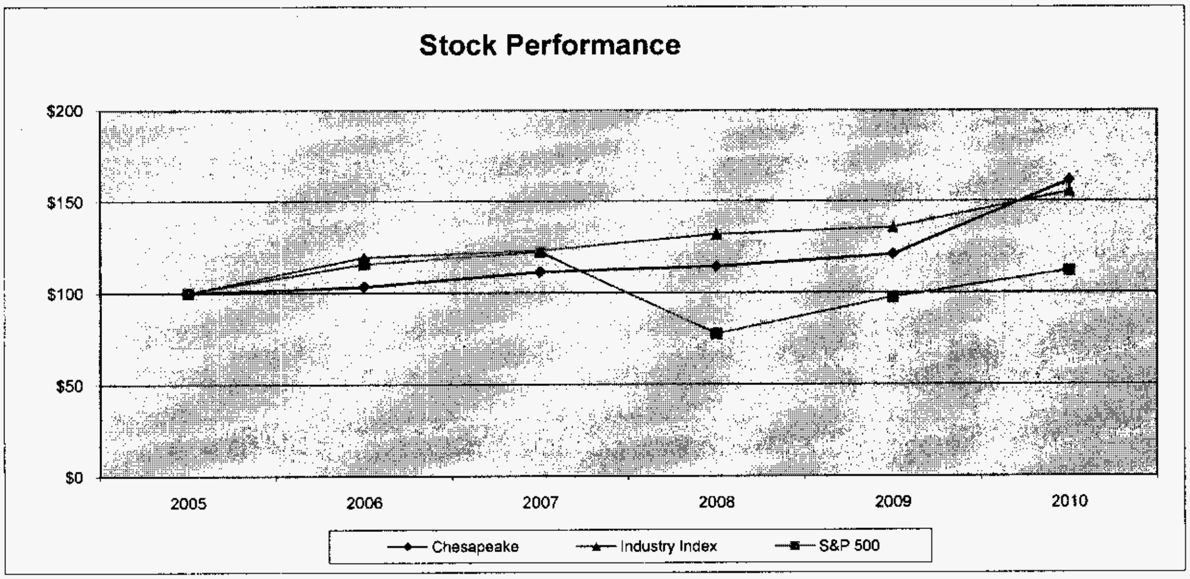
Discussion of compensation plans of Chesapeake and its subsidiaries, for which shares of Chesapeake common stock are authorized for issuance, is included in the portion of the Proxy Statement captioned "Equity Compensation Plan Information" to be filed no later than March 31, 2011, in connection with the Company's Annual Meeting to be held on or about May 4, 2011 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, 2010, 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 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., Gas Natural, 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.

The comparison assumes $100 was invested on December 31, 2005 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.



	2005	2006	2007	2008	2009	2010
Chesapeake	$100	$103	$111	$114	$121	$161
Industry Index	$100	$119	$123	$132	$136	$155
S&P 500 Index	$100	$116	$122	$ 77	$ 97	$112

ITEM 6. SELECTED FINANCIAL DATA

For the Years Ended December 31,	2010	2009[2]	2008
Operating [1]			
(in thousands)			
Revenues			
Regulated Energy	**$269,934**	$139,099	$116,468
Unregulated Energy	**146,793**	119,973	161,290
Other	**10,819**	9,713	13,685
Total revenues	**$427,546**	$268,785	$291,443
Operating income			
Regulated Energy	**$43,509**	$26,900	$24,733
Unregulated Energy	**7,908**	8,158	3,781
Other	**513**	(1,322)	(35)
Total operating income	**$51,930**	$33,736	$28,479
Net income from continuing operations	**$26,056**	$15,897	$13,607
Assets			
(in thousands)			
Gross property, plant and equipment	**$584,385**	$543,905	$381,689
Net property, plant and equipment	**$462,757**	$436,587	$280,671
Total assets	**$670,993**	$615,811	$385,795
Capital expenditures [1]	**$46,955**	$26,294	$30,844
Capitalization			
(in thousands)			
Stockholders' equity	**$226,239**	$209,781	$123,073
Long-term debt, net of current maturities	**89,642**	98,814	86,422
Total capitalization	**$315,881**	$308,595	$209,495
Current portion of long-term debt	**9,216**	35,299	6,656
Short-term debt	**63,958**	30,023	33,000
Total capitalization and short-term financing	**$389,055**	$373,917	$249,151

[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] 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 additional discussions and presentation of pro forma results.

[3] 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.

2007	2006 (3)	2005	2004	2003	2002	2001
$128,850	$124,631	$124,563	$98,139	$92,079	$82,098	$87,444
115,190	94,320	90,995	67,607	59,197	40,728	56,970
14,246	12,249	13,927	12,209	12,292	12,430	13,992
$258,286	$231,200	$229,485	$177,955	$163,568	$135,256	$158,406
$21,809	$18,593	$16,248	$16,258	$16,219	$14,867	$14,060
5,174	3,675	4,197	3,197	4,310	1,158	1,259
1,131	1,064	1,476	722	1,050	580	902
$28,114	$23,332	$21,921	$20,177	$21,579	$16,605	$16,221
$13,218	$10,748	$10,699	$9,686	$10,079	$7,535	$7,341
$352,838	$325,836	$280,345	$250,267	$234,919	$229,128	$216,903
$260,423	$240,825	$201,504	$177,053	$167,872	$166,846	$161,014
$381,557	$325,585	$295,980	$241,938	$222,058	$223,721	$222,229
$30,142	$49,154	$33,423	$17,830	$11,822	$13,836	$26,293
$119,576	$111,152	$84,757	$77,962	$72,939	$67,350	$67,517
63,256	71,050	58,991	66,190	69,416	73,408	48,409
$182,832	$182,202	$143,748	$144,152	$142,355	$140,758	$115,926
7,656	7,656	4,929	2,909	3,665	3,938	2,686
45,664	27,554	35,482	5,002	3,515	10,900	42,100
$236,152	$217,412	$184,159	$152,063	$149,535	$155,596	$160,712

For the Years Ended December 31,	2010	2009[3]	2008
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [1]	**$2.75**	$2.17	$2.00
Diluted earnings per share from continuing operations [1]	**$2.73**	$2.15	$1.98
Return on average equity from continuing operations [1]	**11.6%**	11.2%	11.2%
Common equity / total capitalization	**71.6%**	68.0%	58.7%
Common equity / total capitalization and short-term financing	**58.2%**	56.1%	49.4%
Book value per share	**$23.75**	$22.33	$18.03
Market price:			
High	**$42.200**	$35.000	$34.840
Low	**$28.010**	$22.020	$21.930
Close	**$41.520**	$32.050	$31.480
Average number of shares outstanding	**9,474,554**	7,313,320	6,811,848
Shares outstanding at year-end	**9,524,195**	9,394,314	6,827,121
Registered common shareholders	**2,482**	2,670	1,914
Cash dividends declared per share	**$1.31**	$1.25	$1.21
Dividend yield (annualized) [2]	**3.2%**	3.9%	3.9%
Payout ratio from continuing operations [1][4]	**47.6%**	57.6%	60.5%
Additional Data			
Customers [5]			
Natural gas distribution	**120,230**	117,887	65,201
Electric distribution	**30,966**	31,030	-
Propane distribution	**48,100**	48,680	34,981
Volumes[6]			
Natural gas deliveries (in Mcfs)	**41,795,438**	44,586,158	39,778,067
Electric Distribution (in MWHs)	**739,656**	105,739	-
Propane distribution (in thousands of gallons)	**39,612**	32,546	27,956
Heating degree-days (Delmarva Peninsula)			
Actual HDD	**4,831**	4,729	4,431
10-year average HDD (normal)	**4,528**	4,462	4,401
Propane bulk storage capacity (in thousands of gallons)	**3,041**	3,042	2,471
Total employees [1][7]	**734**	757	448

[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] 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 additional 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.

2007	2006 (8)	2005	2004	2003	2002	2001
$1.96	$1.78	$1.83	$1.68	$1.80	$1.37	$1.37
$1.94	$1.76	$1.81	$1.64	$1.76	$1.37	$1.35
11.5%	11.0%	13.2%	12.8%	14.4%	11.2%	11.1%
65.4%	61.0%	59.0%	54.1%	51.2%	47.8%	58.2%
50.6%	51.1%	46.0%	51.3%	48.8%	43.3%	42.0%
$17.64	$16.62	$14.41	$13.49	$12.89	$12.16	$12.45
$37.250	$35.650	$35.780	$27.550	$26.700	$21.990	$19.900
$28.000	$27.900	$23.600	$20.420	$18.400	$16.500	$17.375
$31.850	$30.650	$30.800	$26.700	$26.050	$18.300	$19.800
6,743,041	6,032,462	5,836,463	5,735,405	5,610,592	5,489,424	5,367,433
6,777,410	6,688,084	5,883,099	5,778,976	5,660,594	5,537,710	5,424,962
1,920	1,978	2,026	2,026	2,069	2,130	2,171
$1.18	$1.16	$1.14	$1.12	$1.10	$1.10	$1.10
3.7%	3.8%	3.7%	4.2%	4.2%	6.0%	5.6%
60.2%	65.2%	62.3%	66.7%	61.1%	80.3%	80.3%
62,884	59,132	54,786	50,878	47,649	45,133	42,741
-	-	-	-	-	-	-
34,143	33,282	32,117	34,888	34,894	34,566	35,530
34,820,050	34,321,160	34,980,939	31,429,494	29,374,818	27,934,715	27,263,542
-	-	-	-	-	-	-
29,785	24,243	26,178	24,979	25,147	21,185	23,080
4,504	3,931	4,792	4,553	4,715	4,161	4,368
4,376	4,372	4,436	4,389	4,409	4,393	4,446
2,441	2,315	2,315	2,045	2,195	2,151	1,958
445	437	423	426	439	455	458

(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.

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

This section provides management's discussion of Chesapeake and its consolidated subsidiaries, with specific information on results of operations, liquidity and capital resources, as well as discussion 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 as well as investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

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

The following discussions and those later in the document on operating income and segment results include use of the term "gross margin." Gross margin is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated energy operations and under its competitive pricing structure for unregulated natural gas marketing, and propane distribution operations. 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, for comparison purposes, includes only FPU's results of operations or exclude FPU's results from the consolidated results of operations for the periods from the merger closing (October 28, 2009) to December 31, 2009 and in 2010. Certain other information is presented, which, for comparison purposes, excludes 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 include only the FPU results, or which exclude 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.

The following discussion sometimes refers to "legacy Chesapeake" and words of similar import. Such terms and phrases mean our results, excluding the impacts from the FPU merger and merger-related costs

(a) Introduction

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

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

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through leveraging our community gas system services and our bulk delivery capabilities;
- utilizing our expertise across our various businesses to improve overall performance;
- enhancing marketing channels to attract new customers;

- providing reliable and responsive customer service to retain existing customers;
- maintaining a capital structure that enables us to access capital as needed;
- maintaining a consistent and competitive dividend for shareholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

(b) Highlights and Recent Developments

(in thousands except per share)

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Net income	**$26,056**	$15,897	$10,159	$15,897	$13,607	$2,290
Earnings per common stock - diluted	**$2.73**	$2.15	$0.58	$2.15	$1.98	$0.17
Components of net income:						
Legacy Cheapeake	**$17,192**	$15,303	$1,889	$15,303	$14,299	$1,004
FPU	**9,339**	1,829	7,510	1,829	-	1,829
Merger-related costs	**(475)**	(1,235)	760	(1,235)	(692)	(543)
Total	**$26,056**	$15,897	$10,159	$15,897	$13,607	$2,290
Components of EPS - diluted						
Legacy Chesapeake [1]	**$2.44**	$2.20	$0.24	$2.20	$2.08	$0.12
FPU [2]	**$0.34**	$0.12	$0.22	$0.12	$0.00	$0.12
Merger-related costs	**($0.05)**	($0.17)	$0.12	($0.17)	($0.10)	($0.07)
Total	**$2.73**	$2.15	$0.58	$2.15	$1.98	$0.17

[1] Calculated based on weighted average common shares outstanding for the period, which excludes the shares issued in the FPU merger.
[2] Represents the additional EPS generated by FPU's results since the merger.

On October 28, 2009, we completed a merger with FPU. 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. We also now serve approximately 31,000 electric distribution customers in northwest and northeast Florida as a result of the merger. FPU's results have been included in our consolidated results since the completion of the merger.

Excluding the impacts from the FPU merger and merger-related costs, our diluted earnings per share from legacy Chesapeake businesses increased by 11 percent and six percent in 2010 and 2009, respectively, compared to the respective prior year.

The following is a summary of key factors affecting our businesses and their impacts on our results. More detailed discussion and analysis are provided in the "Results of Operations" section. Since FPU's results for the period prior to the merger were not included in our results, the year-over-year variances resulting from the factors described below as they relate to FPU are limited to the period after the merger.

- *Weather.* We measure weather based on the number of heating degree-days ("HDD") for the natural gas and propane distribution operations and the number of HDD and the number of cooling degree-days ("CDD") for the electric distribution operation. We use historical averages as the "normal" weather for this analysis.

  HDD on the Delmarva Peninsula in 2010 increased by 102, or two percent, compared to 2009, and by 303, or seven percent, compared to normal. HDD on the Delmarva Peninsula in 2009 increased by 298, or seven percent, compared to 2008, and by 267, or six percent, compared to normal. We estimate that colder weather contributed approximately $679,000 and $1.6 million in additional gross margin for our Delmarva natural gas and propane distribution operations in 2010 and 2009, respectively, compared to the respective prior year. We also estimate that the effect of the colder-than-normal temperatures on the Delmarva Peninsula in 2010 was increased gross margin of $1.6 million for our Delmarva natural gas and propane distribution operations.

The colder temperatures in 2010 in Florida produced average HDD that were 590, or 65 percent, higher than 2009 and 582, or 63 percent, higher than normal. The average HDD in 2009 and 2008 were fairly consistent and did not fluctuate significantly from the normal weather. The warmer temperatures in the summer of 2010 also produced average CDD for the year that were 89, or three percent, higher than the prior year and 141, or five percent, higher than normal. We estimate that colder weather in the winter months and warmer weather in the summer months contributed approximately $1.4 million in additional gross margin for our Florida natural gas and electric distribution operations in 2010, compared to 2009.

- *Growth.* Despite the continued slowdown in growth and overall economic conditions on the Delmarva Peninsula, our Delmarva natural gas distribution operations achieved two percent growth in average residential customers in both 2010 and 2009, compared to the respective prior year. These growth rates exceeded the industry's growth rates. In addition to the residential growth, in 2010, our Delmarva natural gas distribution operations added 10 large commercial and industrial customers with total expected annual margin of $748,000, as they were able to convert these customers to natural gas from other energy sources due to the pricing advantage of natural gas and its environmentally-friendly features. In total, customer growth for the Delmarva natural gas distribution operations generated additional margin of $1.1 million and $1.2 million in 2010 and 2009, respectively, compared to the respective prior year. The addition of certain industrial customers in 2010 also positioned us to further extend our natural gas distribution and transmission infrastructure in southern Delaware to serve other potential customers in the same area.

  ESNG continued to expand its infrastructure and add new transportation services. The additional margin generated from the continued expansions and new services, net of the expired services, was $1.1 million and $1.8 million in 2010 and 2009, respectively, compared to the respective prior year. Although not affecting our results in 2010, ESNG completed the eight-mile mainline extension in December 2010 to interconnect with the TETLP pipeline. ESNG commenced its new transportation services to Chesapeake's Delaware and Maryland divisions in January 2011. The new transportation services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated annualized margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter.

  FPU's natural gas distribution operation experienced growth in commercial and industrial customers in 2010, which contributed $196,000 in additional margin in 2010. Chesapeake's Florida natural gas distribution division experienced a slight growth in customers in 2010 after experiencing a net customer loss in 2009, including a loss of three large industrial customers, in Florida in late 2008 and 2009, which decreased its margin by $190,000 in 2009 compared to 2008. Customer growth in the Florida electric and propane distribution operations was flat.

- *Rates and Regulatory Matters.* On January 14, 2010, new rates for Chesapeake's Florida natural gas distribution division became effective. The new rates for Chesapeake's Florida natural gas distribution division represented an annual rate increase of approximately $2.5 million and generated $2.3 million in increased margin in 2010, net of the impact from the interim rates in 2009, compared to 2009. An annual rate increase of approximately $8.0 million for FPU's natural gas distribution operation pursuant to the settlement agreement also became effective on January 14, 2010. The Florida PSC previously issued an Order in May 2009, approving a rate increase for FPU's natural gas distribution operation. The subsequent protest by the Office of Public Counsel of Florida led to this settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved in December 2009.

The merger with FPU and the purchase of the operating assets of IGC resulted in approximately $34.9 million in purchase premium, which we intend to seek the recovery through rates. We also intend to seek the recovery of approximately $2.2 million in merger-related costs attributed to the natural gas operations. Our Florida natural gas distribution operations are required to submit to the Florida PSC by April 29, 2011 data that details benefits, synergies, cost savings and cost increases resulting from the merger. We are currently in the process of discussing with the Office of Public Counsel and the Florida PSC staff the benefits and cost savings resulted from the merger, current and expected operating results of the regulated operations in Florida, and recovery of the purchase premium and merger-related costs. Our results in 2010 reflect an accrual of $750,000 by FPU's natural gas distribution operation for the regulatory risk associated with earnings, merger benefits and recovery of purchase premium and merger-related costs. Also reflected in our 2010 results were approximately $75,000 of the costs associated with these discussions, which were expensed in 2010.

Although not affecting our results in 2010, ESNG filed a proposed rate increase with the FERC on December 30, 2010. ESNG expects this base rate proceeding to be completed in 2011. ESNG expensed approximately $147,000 in costs associated with this filing in 2010.

- *Propane Prices.* A sharp decline in propane prices in the winter months when our propane inventory is at its highest level exposes us to inventory valuation risk as GAAP requires us to re-value the propane inventory using the "lower-of-cost-or-market" approach. We have implemented various propane supply and inventory strategies to hedge such risk. In late 2008, a sharp decline in propane prices resulted in inventory and swap valuation adjustments of $1.8 million in 2008, which lowered the propane inventory cost of our Delmarva propane distribution operation 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. Retail margins returned to more normal levels in 2010.

  Continued lack of volatility in wholesale propane prices reduced the opportunities for our propane wholesale marketing subsidiary, Xeron, and decreased its trading volume by 13 percent and 57 percent in 2010 and 2009, respectively, compared to the respective prior year. The lower volumes reduced gross margin by approximately $441,000 and $1.0 million for 2010 and 2009, respectively, over the prior year.

- *Natural Gas Spot Sale Opportunities.* Our unregulated natural gas marketing subsidiary, PESCO, entered into spot sales in 2009 with a refinery on the Delmarva Peninsula, which contributed significantly to PESCO's gross margin increase of $1.0 million in 2009. The absence of spot sales opportunities to the same customer in 2010 reduced PESCO's margin in 2010, compared to 2009. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts.

- *Interest Rates.* We continued to experience low short-term interest rates throughout 2010 and 2009 as our short-term weighted average interest rate approximated 1.77 percent in 2010, 1.28 percent in 2009, and 2.79 percent in 2008. The level of our short-term borrowings in 2010 increased over 2009 as we used a new short-term term loan facility to finance the redemption of $29.1 million of FPU's 6.85 percent and 4.90 percent secured first mortgage bonds prior to their respective maturities. 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.

- *Advanced Information Services.* Our advanced information services subsidiary, BravePoint, generated $759,000 in operating income in 2010, compared to an operating loss of $229,000 in 2009. Increased billable consulting hours in 2010 and cost containment actions implemented throughout 2009 contributed to the increased operating results.

(c) Critical Accounting Policies

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

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 980, "Regulated Operations," 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 $23.9 million and regulatory liabilities of $47.8 million, at December 31, 2010. 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 P, 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 MGP 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, 2010, we have recorded environmental regulatory and other assets of $7.5 million and a liability of $12.0 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, 2010 and 2009:

- During 2010 and 2009, our natural gas distribution, electric distribution, propane distribution and natural gas marketing operations entered into physical contracts for the purchase or sale of natural gas, electricity and propane. These contracts either did not meet the definition of derivatives as they did not have a minimum requirement to purchase/sell or were considered "normal purchases and sales" as they provided for the purchase or sale of natural gas, electricity or propane to be delivered in quantities expected to be used and sold by our operations over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

- During 2010 and 2009, the propane distribution operation entered into a put option to protect it from the impact of price decreases on the Pro-Cap (propane price-cap) Plan that we offer to customers. We accounted for the put option on a mark-to-market basis and recorded a loss of $168,000 and $41,000, at December 31, 2010 and 2009, respectively.

- 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, 2010 and 2009, these contracts had net unrealized gains of $284,000 and net unrealized losses of $1.6 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 an alternative to negotiated rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. In connection with this accrual, we must estimate amounts of natural gas and electricity that have 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 statement of income. For certain propane distribution customers without meters and advanced information services customers, we record revenue in the period the products are delivered and/or services are rendered.

Each of our natural gas distribution operations in Delaware and Maryland, our bundled natural gas distribution service in Florida and our electric distribution operation in Florida has a purchased fuel cost recovery mechanism. This mechanism provides us with a method of adjusting billing rates to customers to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered purchased fuel 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 we nor any of our 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.

Pension and Other Postretirement Benefits

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

The total pension and other postretirement benefit costs included in operating income were $2.0 million, $892,000 and $537,000, in 2010, 2009 and 2008, respectively. We expect to record pension and postretirement benefit costs of approximately $2.0 million for 2011, of which $455,000 are settlement losses related to lump-sum distributions we expect to make during 2011, from the Chesapeake Pension Plan and the Chesapeake SERP related to the retirement of our former Chief Executive Officer, who retired in January 2011. Actuarial assumptions affecting 2011 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 5.00 percent and 5.25 percent for Chesapeake's plans and FPU's plans, respectively. The discount rate for each plan was determined by management considering high quality corporate bond rates 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.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent increase in the discount rate could decrease our pension and postretirement costs by approximately $98,000 and a decrease of 0.25 percent could increase our pension and postretirement costs by $123,000. A 0.25 percent increase in the rate of return would decrease our pension cost by approximately $112,000, and a decrease of 0.25 percent could increase our pension cost by approximately $117,000 and will not have an impact on postretirement and SERP plans because these plans are not funded.

Acquisition Accounting

The merger with FPU and other acquisitions were 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. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature of the assets and liabilities and the regulatory mechanism for recovery, to which these assets and liabilities are subject, 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 our value of net assets and future earnings.

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. We deferred a certain portion of the total costs incurred as a regulatory asset, which represents our best estimate of the costs, which we expect to be permitted to recover when we complete the appropriate rate proceedings based on similar proceedings in Florida in the past. The remaining costs have been expensed.

(d) Results of Operations

(in thousands except per share)

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Business Segment:						
Regulated Energy	**$43,509**	$26,900	$16,609	$26,900	$24,733	$2,167
Unregulated Energy	**7,908**	8,158	(250)	8,158	3,781	4,377
Other	**513**	(1,322)	1,835	(1,322)	(35)	(1,287)
Operating Income	**51,930**	33,736	18,194	33,736	28,479	5,257
Other Income	**195**	165	30	165	103	62
Interest Charges	**9,146**	7,086	2,060	7,086	6,158	928
Income Taxes	**16,923**	10,918	6,005	10,918	8,817	2,101
Net Income	**$26,056**	$15,897	$10,159	$15,897	$13,607	$2,290
Earnings Per Share of Common Stock						
Basic	**$2.75**	$2.17	$0.58	$2.17	$2.00	$0.17
Diluted	**$2.73**	$2.15	$0.58	$2.15	$1.98	$0.17

2010 compared to 2009

Our net income increased by approximately $10.2 million, or $0.58 per share (diluted) in 2010, compared to 2009. Chesapeake's legacy businesses, which exclude the FPU business and merger-related costs, generated an increase in net income of $1.9 million, or $0.24 per share (diluted) in 2010. The $0.24 per share increase in diluted earnings per share by Chesapeake's legacy businesses in 2010, which is calculated based on weighted average common shares outstanding, exclusive of the shares issued in the FPU merger, represents 11-percent growth from 2009. Continued growth and expansions of our natural gas distribution and transmission businesses and propane distribution business on the Delmarva Peninsula, the rate increase in Chesapeake's Florida natural gas distribution division, favorable weather impact and improved results in our advanced information services business contributed to this increase. These increases were partially offset by a decline in earnings from our natural gas marketing business, due primarily to the absence of spot sales to one industrial customer, and our propane wholesale marketing business. FPU's results, which have been included in our consolidated results since the completion of the merger on October 28, 2009, added $7.5 million to our consolidated net income in 2010, which generated an increase of $0.22 per share (diluted) in 2010. A decrease in FPU merger-related costs also added $0.12 per share (diluted) to the increase in 2010.

The following table illustrates the effect of the merger on our results for the year ended December 31, 2010 and December 31, 2009.

	2010			2009		
For the Years Ended December 31,	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**	**Chesapeake, excluding FPU**	**FPU [1]**	**Chesapeake Total**
(in thousands)						
Operating Income (Loss)						
Regulated Energy	$26,711	$16,798	$43,509	$23,908	$2,992	$26,900
Unregulated Energy	6,335	1,573	7,908	7,605	553	8,158
Other, including merger-related costs	513	-	513	(1,322)	-	(1,322)
Operating Income	33,559	18,371	51,930	30,191	3,545	33,736
Other Income, net of expenses	48	147	195	58	107	165
Interest Charges	5,752	3,394	9,146	6,345	741	7,086
Income Taxes	11,138	5,785	16,923	9,836	1,082	10,918
Net Income	$16,717	$9,339	$26,056	$14,068	$1,829	$15,897

[1] FPU operating results are for the period from the merger closing (October 28, 2009) to December 31, 2009

2009 compared to 2008

Our net income increased by approximately $2.3 million, or $0.17 per share (diluted), in 2009, compared to 2008. Excluding FPU's results and the merger-related costs, Chesapeake's legacy businesses generated an increase in net income of $1.0 million, or $0.12 per share (diluted) in 2009. This increase in the diluted earnings per share, which is calculated based on weighted average common shares outstanding, exclusive of the shares issued in the FPU merger, represents five-percent growth in 2009. Continued growth and expansions in our natural gas distribution and transmission businesses on the Delmarva Peninsula, and increased retail margins in the propane distribution business, favorable weather impact and spot sale opportunities by our natural gas marketing business contributed to this increase. FPU's net income included in our consolidated results in 2009, which represents its net income since the completion of the merger, was $1.8 million, generating an additional $0.12 per share (diluted).

The following table illustrates the effect of the merger on our results for the year ended December 31, 2009 and the results in 2008.

	2009			2008		
For the Years Ended December 31,	**Chesapeake, excluding FPU**	**FPU [(1)]**	**Chesapeake Total**	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**
(in thousands)						
Operating Income (Loss)						
Regulated Energy	**$23,908**	**$2,992**	**$26,900**	$24,733	$0	$24,733
Unregulated Energy	**7,605**	**553**	**8,158**	3,781	-	3,781
Other	**(1,322)**	**-**	**(1,322)**	(35)	-	(35)
Operating Income	**30,191**	**3,545**	**33,736**	28,479	0	28,479
Other Income, net of expenses	**58**	**107**	**165**	103	-	103
Interest Charges	**6,345**	**741**	**7,086**	6,158	-	6,158
Income Taxes	**9,836**	**1,082**	**10,918**	8,817	-	8,817
Net Income	**$14,068**	**$1,829**	**$15,897**	$13,607	$0	$13,607

[(1)] FPU operating results are for the period from the merger closing (October 28, 2009) to December 31, 2009

Regulated Energy

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
(in thousands)						
Revenue	**$269,934**	$139,099	$130,835	$139,099	$116,468	$22,631
Cost of sales	**144,217**	64,803	79,414	64,803	54,789	10,014
Gross margin	**125,717**	74,296	51,421	74,296	61,679	12,617
Operations & maintenance	**56,338**	32,569	23,769	32,569	25,369	7,200
Depreciation & amortization	**17,038**	8,866	8,172	8,866	6,694	2,172
Other taxes	**8,832**	5,961	2,871	5,961	4,883	1,078
Other operating expenses	**82,208**	47,396	34,812	47,396	36,946	10,450
Operating Income	**$43,509**	$26,900	$16,609	$26,900	$24,733	$2,167

Weather and Customer Analysis

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Delmarva Peninsula						
Actual HDD	**4,831**	4,729	102	4,729	4,431	298
10-year average HDD	**4,528**	4,462	66	4,462	4,401	61
Estimated gross margin per HDD	**$1,995**	$2,429	($434)	$2,429	$1,937	$492
Florida						
Actual HDD	**1,501**	911	590	911	851	60
10-year average HDD	**919**	863	56	863	848	15
Actual CDD	**2,859**	2,770	89	2,770	2,553	217
10-year average CDD	**2,718**	2,694	24	2,694	2,687	7
Average number of residential customers						
Delmarva natural gas distribution	**47,638**	46,717	921	46,717	45,570	1,147
Florida natural gas distribution[1]	**61,053**	60,048	1,005	60,048	13,373	46,675
Florida electric distribution [1]	**23,589**	23,679	(90)	23,679	-	23,679
Total	**132,280**	130,444	1,836	130,444	58,943	71,501

[1] Average number of residential customers for FPU are included in 2010 and 2009.

2010 Compared to 2009

Operating income for the regulated energy segment increased by approximately $16.6 million, or 62 percent, in 2010, compared to 2009, which was generated from a gross margin increase of $51.4 million, offset partially by an operating expense increase of $34.8 million. Our 2010 results include 12 months of FPU's results, whereas 2009 includes only two months.

Gross Margin

Gross margin for our regulated energy segment increased by $51.4 million, or 69 percent. Of the $51.4 million increase, Chesapeake's legacy regulated energy businesses generated $5.2 million of the increase, or 10 percent. FPU's natural gas and electric distribution operations contributed $46.2 million of this increase. FPU's results in 2009 have been included in our results since the completion of the merger on October 28, 2009. Our results for 2010 included FPU's results for the full year.

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

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

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

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

Our Florida natural gas distribution operations experienced an increase in gross margin of $33.5 million in 2010. The factors contributing to this increase were as follows:

- FPU's natural gas distribution operation generated $37.1 million in gross margin for 2010, which includes $148,000 of gross margin generated by the purchase of operating assets from IGC on August 9, 2010. Included in gross margin from FPU's natural gas distribution operation in 2009 was $6.4 million. Gross margin from FPU's natural gas distribution operation in 2010 was positively affected by an annual rate increase of approximately $8.0 million, effective January 14, 2010, colder temperatures in Florida and growth in commercial and industrial customers. Included in gross margin from FPU's natural gas distribution operation was the impact of a $750,000 accrual related to the regulatory risk associated with its earnings, merger benefits and recovery of purchase premium. FPU is required to detail known benefits, synergies, cost savings and cost increases resulting from the merger and present the information in the "come-back" filing to the Florida PSC by April 29, 2011 (within 18 months of the merger). We are currently in discussions with the Office of Public Counsel and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings levels as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. We recorded this accrual based on our assessment of FPU's current earnings, the regulatory environment in Florida and progress of the current discussions.

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

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

- New transportation services implemented by ESNG in November 2009, May 2010 and November 2010 as a result of its system expansion projects generated an additional $1.1 million to gross margin in 2010, compared to 2009. These expansion projects added 9,623 Mcfs of service per day with estimated annual gross margin of $1.6 million, of which $1.2 million has been reflected in 2010's results.

- New firm transportation service for an industrial customer for the period from November 2009 to October 2012 provided an additional 9,662 Mcfs per day for the period January 1, 2010 through February 5, 2010, and an additional 2,705 Mcfs per day for the period February 6, 2010 through October 31, 2010. These new services added $329,000 to gross margin for 2010. Partially offsetting the additional gross margin generated by this new firm transportation service was the margin of $232,000 in 2009 from the temporary interruptible service provided to the same customer. This temporary increase in service did not occur in 2010.

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

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

- Although not affecting our results in 2010, ESNG completed the eight-mile mainline extension in December 2010 to interconnect with the TETLP pipeline. ESNG commenced its new transportation services to Chesapeake's Delaware and Maryland divisions in January 2011. These new services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter.

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

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $34.8 million, or 73 percent, in 2010, of which $32.4 million was related to other operating expenses of FPU. The remaining increase of $2.4 million or a five percent increase from other operating expenses in 2009, exclusive of other operating expenses of FPU, was due primarily to the following factors:

- Payroll and benefits increased by $705,000 due primarily to annual salary increases and incentive pay as a result of improved performance.

- Depreciation and asset removal costs increased by $518,000 as a result of our increased capital investments made in 2010 and 2009 to support growth.

- Regulatory expenses increased by $349,000 due primarily to costs associated with ESNG's recent rate case filing and ongoing regulatory discussions involving the merger impact and recovery of the purchase premium in Florida.

- Non-income-taxes increased by $63,000 due primarily to increased gross receipt tax.

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 were as follows:

- 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, in spite of the continued slowdown in the new housing construction and industrial growth in the region. 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.
- Colder weather on the Delmarva Peninsula contributed $449,000 to the increased gross margin, as HDD 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, were previously 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.

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 the 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 in gross margin of $99,000 due to implementation of interim natural gas 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 were 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 for: (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. These services generate annual gross margin of $1.1 million.
- 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 intrastate 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 was 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 was 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.
- 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 overall increase in corporate overhead costs. This increase was related primarily to increased payroll and benefits and increased costs associated with investor relations and financial reporting activities.

Unregulated Energy

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
(in thousands)						
Revenue	**$146,793**	$119,973	$26,820	$119,973	$161,290	($41,317)
Cost of sales	**110,680**	90,408	20,272	90,408	138,302	(47,894)
Gross margin	**36,113**	29,565	6,548	29,565	22,988	6,577
Operations & maintenance	**23,140**	18,016	5,124	18,016	16,322	1,694
Depreciation & amortization	**3,433**	2,415	1,018	2,415	2,024	391
Other taxes	**1,632**	976	656	976	861	115
Other operating expenses	**28,205**	21,407	6,798	21,407	19,207	2,200
Operating Income	**$7,908**	$8,158	($250)	$8,158	$3,781	$4,377

Weather Analysis — Delmarva

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Actual HDD	**4,831**	4,729	102	4,729	4,431	298
10-year average HDD	**4,528**	4,462	66	4,462	4,401	61
Estimated gross margin per HDD	**$2,415**	$3,083	($668)	$3,083	$2,465	$618

2009 compared to 2008

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.

Gross Margin

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 volumes 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 enabled 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.

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 was 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.
- Corporate overhead costs allocated to the unregulated energy segment increased by approximately $568,000 due to the overall increase in administrative payroll and benefits and increased costs associated with investor relations and financial reporting activities.
- These increases were partially offset by lower vehicle-related costs of $176,000, due primarily to a decrease in the cost of fuel.

Other

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
(in thousands)						
Revenue	**$13,142**	$11,998	$1,144	$11,998	$15,373	($3,375)
Cost of sales	**6,316**	6,036	280	6,036	8,034	(1,998)
Gross margin	**6,826**	5,962	864	5,962	7,339	(1,377)
Operations & maintenance	**4,766**	4,859	(93)	4,859	5,206	(347)
Transaction-related costs	**660**	1,478	(818)	1,478	1,153	325
Depreciation & amortization	**289**	310	(21)	310	290	20
Other taxes	**600**	640	(40)	640	728	(88)
Other operating expenses	**6,315**	7,287	(972)	7,287	7,377	(90)
Operating Income — Other	**511**	(1,325)	1,836	(1,325)	(38)	(1,287)
Operating Income — Eliminations	**2**	3	(1)	3	3	-
Operating Income	**$513**	($1,322)	1,835	($1,322)	($35)	($1,287)

2010 Compared to 2009

Operating income for the "Other" segment increased by approximately $1.8 million in 2010, compared to 2009. The increase in operating income was attributable to a gross margin increase of $864,000 and a $972,000 decrease in operating expenses.

Gross margin

The period-over-period increase in gross margin of $864,000 for our "Other" segment was generated by our advanced information services subsidiary's increase in revenue and gross margin from its professional database monitoring and support solution services and higher consulting revenues as a result of a seven-percent increase in the number of billable consulting hours in 2010 compared to 2009.

Operating expenses

Other operating expenses decreased by $972,000 in 2010 compared to 2009. The decrease in operating expenses was attributable primarily to an $818,000 decrease in merger-related costs expensed in 2010 compared to 2009.

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 subsidiary 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 was a result of economic conditions. The decrease in consulting revenues was partially offset by an increase of $218,000 from BravePoint's professional database monitoring and support solution services, and increased product sales of $140,000.

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 services subsidiary in 2009 to reduce costs to offset the decline in revenues. This decrease was offset by the increased merger-related costs.

Other Income

Other income for 2010, 2009 and 2008 was $195,000, $165,000, and $103,000, respectively, which includes interest income, late fees charged to customers and gains or losses from the sale of assets.

Interest Expense

2010 Compared to 2009

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

- An increase in long-term interest expense of $1.3 million was related to interest on FPU's first mortgage bonds.
- Interest expense from a new term loan credit facility during 2010 was $491,000. In January 2010, we redeemed two series of FPU bonds, the 4.9 percent and 6.85 percent series, to achieve interest savings and to maintain compliance with the covenants in our unsecured senior notes. We used $29.1 million of the new term loan facility for the redemptions.
- Additional interest expense of $730,000 is related to interest on deposits from FPU's customers.

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

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 was 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 fairly constant at 6.37 percent in 2009, compared to 6.40 percent in 2008.
- Interest expense on short-term borrowings 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 in addition to a decline in working capital requirements in 2009, 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 increased working capital needs as a result of the FPU merger. Also contributing to the decrease in interest expense in short-term borrowings 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.

Income Taxes

2010 Compared to 2009

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

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 we 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.

(e) Liquidity and Capital Resources

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

Our energy businesses are weather sensitive and seasonal. We 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.

Capital expenditures are one of our largest capital requirements. During 2010, our capital expenditures increased to $47.0 million, from $26.3 million and $30.8 million in 2009 and 2008, respectively, as a result of continued expansions of our natural gas distribution and transmission systems as well as capital expenditures for FPU of $10.9 million and $1.6 million included in our capital expenditures in 2010 and 2009 since the completion of the merger. We have budgeted $51.7 million for capital expenditures during 2011. This amount includes $43.6 million for the regulated energy segment, $3.7 million for the unregulated energy segment and $4.4 million for the "Other" segment. The amount for the regulated energy segment includes estimated capital expenditures for the following: natural gas distribution operation ($25.4 million), natural gas transmission operation ($12.5 million) and electric distribution operation ($5.7 million) for expansion and improvement of facilities. The amount for the unregulated energy segment includes estimated capital expenditures for the propane distribution operations for customer growth and replacement of equipment. The amount for the "Other" segment includes estimated capital expenditures of $245,000 for the advanced information services subsidiary with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2011 capital expenditures program from short-term borrowings, cash provided by operating activities, and other sources. The capital expenditures program is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of December 31, 2010 and 2009:

	December 31, 2010		December 31, 2009	
(in thousands)				
Long-term debt, net of current maturities	**$89,642**	**28%**	$98,814	32%
Stockholders' equity	**226,239**	**72%**	209,781	68%
Total capitalization, excluding short-term debt	**$315,881**	**100%**	$308,595	100%

	December 31, 2010		December 31, 2009	
(in thousands)				
Short-term debt	**$63,958**	**17%**	$30,023	8%
Long-term debt, including current maturities	**98,858**	**25%**	134,113	36%
Stockholders' equity	**226,239**	**58%**	209,781	56%
Total capitalization, including short-term debt	**$389,055**	**100%**	$373,917	100%

In consummating the FPU merger, we issued 2,487,910 shares of Chesapeake common stock, valued at approximately $75.7 million, in exchange for all outstanding common stock of FPU. Our balance sheet at the time of the merger also reflected FPU's long-term debt of $47.8 million as a result of the merger.

Since the consummation of the merger, we have redeemed $29.1 million of FPU's long-term debt, which was held in the form of first mortgage bonds. We will be refinancing these redeemed bonds with new Chesapeake unsecured senior notes. We have also entered into an arrangement to refinance an additional $7.0 million of FPU's first mortgage bonds in 2013 with more competitively priced Chesapeake unsecured senior notes. As a result, only $8.0 million of the original $47.8 million of FPU debt as of the merger will be outstanding by 2013 in the form of secured first mortgage bonds.

As of December 31, 2010, we did not have any restrictions on our cash balances. Both Chesapeake's senior notes and FPU's first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2010, $52.7 million of Chesapeake's cumulative consolidated net income and $28.3 million of FPU's cumulated net income were free of such restrictions.

Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2010 and 2009 were $64.0 million and $30.0 million, respectively, at the weighted average interest rates of 1.77 percent and 1.28 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to fund temporarily portions of the capital expenditure program. As of December 31, 2010, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at December 31, 2010 and 2009 were $30.8 million and $30.0 million, respectively. During 2010, 2009 and 2008, the average borrowings from these unsecured bank lines of credit were $10.5 million, $13.0 million and $38.3 million, respectively, at weighted average interest rates of 2.40 percent, 1.28 percent and 2.80 percent, respectively. The maximum month-end borrowings from these unsecured bank lines of credit during 2010, 2009 and 2008 were $64.0 million, $33.0 million and $61.2 million, respectively, which occurred during the fall and winter months when our working capital requirements were at the highest level. Also included in our outstanding short-term borrowings at December 31, 2010 was $4.1 million in book overdraft representing outstanding checks in excess of funds in deposit, which if presented would be funded through the bank lines of credit.

In addition to the four unsecured bank lines of credit, we entered into a new credit facility for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility to finance the early redemption of the 6.85 percent and 4.90 percent series of FPU's secured first mortgage bonds. The interest rate on the borrowing was fixed at 1.88 percent for nine months and on December 16, 2010 the rate was fixed for three months at 1.55 percent. On November 1, 2010 we extended the maturity of this credit facility from March 15, 2011 until October 31, 2011.

On June 29, 2010, we entered into an agreement with an existing senior note holder to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the early redemption of the 6.85 percent and 4.90 percent series of FPU bonds previously discussed. If refinanced prior to July 8, 2011, these new uncollateralized senior notes will be issued at 5.68 percent and result in annual long-term interest expense of $1.7 million, representing additional interest of $1.2 million, compared to the interest expense of $491,000 on the new short-term loan facility used in 2010. We also expect to use the remaining $7 million to redeem additional FPU secured first mortgage bonds in 2013.

Cash Flows Provided by Operating Activities

Our cash flows provided by operating activities were as follows:

For the Years Ended December 31,	2010	2009	2008
Net income	**$26,056**	$15,897	$13,607
Non-cash adjustments to net income	**37,364**	28,319	22,919
Changes in assets and liabilities	**(2,415)**	1,583	(7,982)
Net cash from operating activities	**$61,005**	$45,799	$28,544

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.

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

- Net cash flows from changes in accounts receivable and accounts payable were due primarily to the inclusion of FPU and timing of collections and payments of trading contracts entered into by our propane wholesale and marketing operation;
- Net income increased by $10.2 million. A full year's results for FPU and organic growth within Chesapeake's legacy businesses contributed to this increase;
- Non-cash adjustments to net income increased by $12.4 million due primarily to higher depreciation and amortization, changes in deferred income taxes, higher employee benefits and compensation and an increase in share based compensation. Higher depreciation and amortization was due to the inclusion of FPU and an increase in capital investments. The increase in deferred income taxes was a result of bonus depreciation in 2010, which significantly reduced our income tax payment obligations in 2010; and
- The decrease in income tax receivables was due primarily to the receipt of large refunds in 2009 due to higher tax deductions in 2009 and 2008 and a decrease in taxes payable due to bonus depreciation in 2010.

In 2009, our net cash flow provided by operating activities was $45.8 million, an increase of $17.3 million compared to 2008. The increase was due primarily to the following:

- Net cash flows from changes in accounts receivable and accounts payable, 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 was 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 2010, net cash flows used by investing activities totaled $48.8 million, an increase of $25.7 million compared to 2009. In 2009, net cash flows used by investing activities totaled $23.1 million, a decrease of $8.1 million compared to 2008.

- Cash utilized for capital expenditures was $45.4 million, $26.6 million and $30.8 million for 2010, 2009, and 2008, respectively.
- We invested $1.6 million in equity securities and paid $1.2 million and $310,000 for the acquisition of Indiantown Gas Company and Virginia LP, respectively, in 2010.
- In 2009, we received $3.5 million in proceeds from an investment account related to future environmental costs, as we transferred the amount to our general account that invests in overnight income-producing securities. We also acquired $359,000 in cash, net of cash paid, in the FPU merger in 2009.
- Environmental expenditures exceeded amounts recovered through rates charged to customers in 2010, 2009 and 2008 by $290,000, $418,000 and $480,000, respectively.

Cash Flows Provided by/Used in Financing Activities

In 2010 and 2009, net cash flows used by financing activities totaled $13.4 million and $21.4 million, respectively, compared to net cash flows provided by financing activities of $1.7 million in 2008. Significant financing activities included the following:

- During 2010 we entered into a new term loan with an existing lender and we borrowed $29.1 million under this facility in order to temporarily finance the early redemption of the 6.85 percent and 4.90 percent series of FPU's secured first mortgage bonds prior to their respective maturity.
- During 2010 we increased our short-term borrowing by $1.6 million primarily to support our capital expenditures. During 2009 and 2008, we reduced our short-term debt by $3.8 million and $12.0 million, respectively.
- We repaid $36.9 million, $10.9 million and $7.7 million of long-term debt during 2010, 2009 and 2008 respectively.
- We paid $11.0 million, $8.0 million and $7.3 million in cash dividends in 2010, 2009 and 2008, respectively. An increase in cash dividends paid in each year reflects the growth in the annualized dividend rate. 2010 also reflects dividends on a larger number of shares outstanding, from the FPU shares that were exchanged for Chesapeake shares in the merger.
- In October 2008, we completed the placement of $30.0 million of 5.93 percent Unsecured Senior Notes.

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2010:

	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]	$9,216	$16,393	$21,656	$51,682	$98,947
Operating leases [2]	803	1,234	470	2,017	4,524
Purchase obligations [3]					
Transmission capacity	35,051	59,761	37,949	70,293	203,054
Storage — Natural Gas	2,615	4,687	1,525	2,063	10,890
Commodities	37,179	100	-	-	37,279
Electric supply	1,626	26,498	26,498	39,173	93,795
Forward purchase contracts — Propane [4]	15,618	-	-	-	15,618
Other	144	109	-	-	253
Unfunded benefits [5]	1,132	731	870	5,706	8,439
Funded benefits [6]	2,400	150	108	1,228	3,886
Total Contractual Obligations	**$105,784**	**$109,663**	**$89,076**	**$172,162**	**$476,685**

(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 $6.6 million, $11.4 million, $8.6 million and $13.3 million, respectively, for the periods indicated above. Expected interest payments for all periods total $40.0 million.

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

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

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

(5) We have recorded long-term liabilities of $8.4 million at December 31, 2010 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 $16.3 million at December 31, 2010 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 $1.5 million, reflecting the expected payments the Company will make to the trust funds in 2011. 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 $2.4 million funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the Balance Sheet. We assume a retirement age of 65 for purposes of distribution from this account.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily 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, 2010 was $25.6 million, with the guarantees expiring on various dates in 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $440,625 which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various insurance outstanding policies. As a result of the recent change in our primary insurance company, we have issued an additional letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of December 31, 2010. We do not anticipate that the letters of credit will be drawn upon by the counterparties and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.0 million to TETLP related to the Precedent Agreement with TETLP. The letter of credit is expected to increase quarterly as TETLP's pre-service costs increases. The letter of credit will not exceed the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

(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, 2010, Chesapeake was involved in rate filings and/or regulatory matters in each of the jurisdictions in which it operates. Each of these rate filings or regulatory matters is fully described in Item 8 under the heading "Notes to the Consolidated Financial Statements – Note O, Rates and Other Regulatory Activities."

(g) Environmental Matters

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

(h) Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses 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 $98.9 million at December 31, 2010, as compared to a fair value of $113.4 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 six 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.

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third-parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of natural gas liquids to us or the counterparty or "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 counterparties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and futures contracts at December 31, 2010 and 2009 is presented in the following tables:

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

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire by the end of the second quarter of 2011.

At December 31, 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, 2010 and 2009, 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, 2010	December 31, 2009
Mark-to-market energy assets	**$1,642**	$2,379
Mark-to-market energy liabilities	**$1,492**	$2,514

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

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

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

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

(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.

(k) Marianna Franchise

On March 2, 2011, the City of Marianna, Florida filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the city to provide electric service to customers within and without the city by failing (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the city and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU's customers located within and without the corporate limits of the city. The city is seeking a declaratory judgment to exercise its option under the franchise agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. If the purchase occurs, FPU would have a gain in the year of the disposition. Additionally, future financial results would be negatively impacted from the loss in earnings generated by FPU under the franchise agreement, however such impact is anticipated to be immaterial. FPU intends to file a response to the City's complaint and vigorously contest this litigation and intends to oppose the passage of any proposed referendum that is presented to voters to approve the purchase of the FPU property in the City of Marianna.

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

Information concerning quantitative and qualitative disclosure about market risk is included in Item 7 under the heading "Management's Discussion and Analysis — 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 which in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. FPU's activity is included in Chesapeake's 2010 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" for additional information relating to the FPU merger.

Chesapeake's management has evaluated and concluded that Chesapeake's internal control over financial reporting was effective as of December 31, 2010.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation (the "Company") as of December 31, 2010 and 2009, 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, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Chesapeake Utilities Corporation as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 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, 2010 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, 2011 expressed an unqualified opinion.

/s/ ParenteBeard LLC
ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2011

Consolidated Statements of Income

For the Years Ended December 31,	2010	2009	2008
(in thousands, except shares and per share data)			
Operating Revenues			
Regulated Energy	**$269,934**	$139,099	$116,468
Unregulated Energy	**146,793**	119,973	161,290
Other	**10,819**	9,713	13,685
Total operating revenues	**427,546**	268,785	291,443
Operating Expenses			
Regulated energy cost of sales	**144,217**	64,803	54,789
Unregulated energy and other cost of sales	**116,098**	95,467	145,854
Operations	**75,335**	50,706	43,476
Transaction-related costs	**660**	1,478	1,153
Maintenance	**7,484**	3,430	2,215
Depreciation and amortization	**20,758**	11,588	9,005
Other taxes	**11,064**	7,577	6,472
Total operating expenses	**375,616**	235,049	262,964
Operating Income	**51,930**	33,736	28,479
Other income, net of other expenses	**195**	165	103
Interest charges	**9,146**	7,086	6,158
Income Before Income Taxes	**42,979**	26,815	22,424
Income taxes	**16,923**	10,918	8,817
Net Income	**$26,056**	$15,897	$13,607
Weighted Average Common Shares Outstanding:			
Basic	**9,474,554**	7,313,320	6,811,848
Diluted	**9,582,374**	7,440,201	6,927,483
Earnings Per Share of Common Stock:			
Basic	**$2.75**	$2.17	$2.00
Diluted	**$2.73**	$2.15	$1.98
Cash Dividends Declared Per Share of Common Stock	**$1.305**	$1.250	$1.210

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

Consolidated Statements of Cash Flows

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Operating Activities			
Net Income	**$26,056**	$15,897	$13,607
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**20,758**	11,588	9,005
Depreciation and accretion included in other costs	**3,133**	2,789	2,239
Deferred income taxes, net	**13,389**	10,065	11,442
Unrealized (gain) loss on commodity contracts	**(116)**	1,606	(1,252)
Unrealized (gain) loss on investments	**(181)**	(212)	509
Employee benefits and compensation	**(757)**	1,217	152
Share based compensation	**1,155**	1,306	820
Other, net	**(17)**	(40)	4
Changes in assets and liabilities:			
Purchase of investments	**(297)**	(146)	(201)
Accounts receivable and accrued revenue	**(20,467)**	(13,652)	19,411
Propane inventory, storage gas and other inventory	**151**	2,597	(1,730)
Regulatory assets	**687**	(1,842)	411
Prepaid expenses and other current assets	**1,157**	(757)	(1,182)
Other deferred charges	**(156)**	(83)	(153)
Long-term receivables	**286**	191	207
Accounts payable and other accrued liabilities	**15,853**	10,185	(15,033)
Income taxes receivable	**(3,761)**	5,020	(6,155)
Accrued interest	**(97)**	66	158
Customer deposits and refunds	**2,038**	(75)	(502)
Accrued compensation	**1,339**	(2,066)	(175)
Regulatory liabilities	**665**	1,071	(3,107)
Other liabilities	**187**	1,074	69
Net cash provided by operating activities	**61,005**	45,799	28,544
Investing Activities			
Property, plant and equipment expenditures	**(45,411)**	(26,603)	(30,756)
Cash acquired in the merger, net of cash paid	**-**	359	-
(Purchases of) proceeds from investments	**(3,108)**	3,519	-
Environmental expenditures	**(290)**	(418)	(480)
Net cash used by investing activities	**(48,809)**	(23,143)	(31,236)
Financing Activities			
Common stock dividends	**(11,013)**	(7,957)	(7,810)
Issuance of stock for Dividend Reinvestment Plan	**568**	392	(118)
Change in cash overdrafts due to outstanding checks	**3,255**	835	(684)
Net borrowing (repayment) under line of credit agreements	**1,579**	(3,812)	(11,980)
Other short-term borrowing	**29,100**	-	29,961
Repayment of long-term debt	**(36,860)**	(10,907)	(7,658)
Net cash provided by (used in) financing activities	**(13,371)**	(21,449)	1,711
Net Increase (Decrease) in Cash and Cash Equivalents	(1,175)	1,207	(981)
Cash and Cash Equivalents — Beginning of Period	**2,818**	1,611	2,592
Cash and Cash Equivalents — End of Period	**$1,643**	$2,818	$1,611

Supplemental Cash Flow Disclosures (see Note D)

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

Consolidated Balance Sheets

Assets	December 31, 2010	December 31, 2009
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	**$500,689**	$462,061
Unregulated energy	**61,313**	61,334
Other	**16,989**	16,049
Total property, plant and equipment	**578,991**	539,444
Less: Accumulated depreciation and amortization	**(121,628)**	(107,318)
Plus: Construction work in progress	**5,394**	4,461
Net property, plant and equipment	**462,757**	436,587
Investments, at fair value	**4,036**	1,959
Current Assets		
Cash and cash equivalents	**1,643**	2,818
Accounts receivable (less allowance for uncollectible accounts of $1,194 and $1,609, respectively)	**88,074**	69,773
Accrued revenue	**14,978**	12,838
Propane inventory, at average cost	**8,876**	7,901
Other inventory, at average cost	**3,084**	3,149
Regulatory assets	**51**	448
Storage gas prepayments	**5,084**	6,144
Income taxes receivable	**6,748**	2,614
Deferred income taxes	**2,191**	724
Prepaid expenses	**4,613**	5,853
Mark-to-market energy assets	**1,642**	2,379
Other current assets	**245**	147
Total current assets	**137,229**	114,788
Deferred Charges and Other Assets		
Goodwill	**35,613**	34,095
Other intangible assets, net	**3,459**	3,951
Long-term receivables	**155**	440
Regulatory assets	**23,884**	20,100
Other deferred charges	**3,860**	3,891
Total deferred charges and other assets	**66,971**	62,477
Total Assets	**$670,993**	$615,811

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

Consolidated Balance Sheets

Capitalization and Liabilities	December 31, 2010	December 31, 2009
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share		
(authorized 25,000,000 and 12,000,000 shares, respectively)	**$4,635**	$4,572
Additional paid-in capital	**148,159**	144,502
Retained earnings	**76,805**	63,231
Accumulated other comprehensive loss	**(3,360)**	(2,524)
Deferred compensation obligation	**777**	739
Treasury stock	**(777)**	(739)
Total stockholders' equity	**226,239**	209,781
Long-term debt, net of current maturities	**89,642**	98,814
Total capitalization	**315,881**	308,595
Current Liabilities		
Current portion of long-term debt	**9,216**	35,299
Short-term borrowing	**63,958**	30,023
Accounts payable	**65,541**	51,462
Customer deposits and refunds	**26,317**	25,046
Accrued interest	**1,789**	1,887
Dividends payable	**3,143**	2,959
Accrued compensation	**6,784**	5,341
Regulatory liabilities	**9,009**	8,295
Mark-to-market energy liabilities	**1,492**	2,514
Other accrued liabilities	**10,393**	7,017
Total current liabilities	**197,642**	169,843
Deferred Credits and Other Liabilities		
Deferred income taxes	**80,031**	66,008
Deferred investment tax credits	**243**	335
Regulatory liabilities	**3,734**	4,393
Environmental liabilities	**10,587**	11,104
Other pension and benefit costs	**18,199**	15,088
Accrued asset removal cost - Regulatory liability	**35,092**	33,214
Other liabilities	**9,584**	7,231
Total deferred credits and other liabilities	**157,470**	137,373
Other commitments and contingencies (Note P and Q)		
Total Capitalization and Liabilities	**$670,993**	$615,811

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

Consolidated Stockholders' Equity

(in thousands, except shares and per share data)	Common Stock: Number of Shares[7]	Common Stock: Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
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
Net Income				26,056				26,056
Other comprehensive income, net of tax								
Employee Benefit Plans, net of tax								
Amortization of prior service costs [4]					8			8
Net loss [5]					(844)			(844)
Total comprehensive income								25,220
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Tax benefit on share based compensation			253					253
Share based compensation [1][3]	36,415	17	620					637
Deferred Compensation Plan [6]						38	(38)	-
Purchase of treasury stock	1,144						(38)	(38)
Sale and distribution of treasury stock	(1,144)						38	38
Dividends on stock-based compensation				(104)				(104)
Cash dividends [2]				(12,378)				(12,378)
Balances at December 31, 2010	9,524,195	$4,635	$148,159	$76,805	($3,360)	$777	($777)	$226,239

[1] Includes amounts for shares issued for Directors' compensation
[2] Cash dividends declared per share for the periods ended December 31, 2010, 2009 and 2008 were $1.305, $1.250 and $1.210 respectively
[3] The shares issued under the Performance Incentive Plan ("PIP") are net of shares withheld for employee taxes. For 2010 and 2008, the Company withheld 17,695 and 12,511 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, 2010, 2009 and 2008 were approximately $5, $5 and ($52) respectively
[5] Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended December 31, 2010, 2009 and 2008 were ($541), $794, ($1,900) respectively.
[6] In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in 2010 and 2008
[7] Includes 29,600, 28,452, and 62,221 shares at December 31, 2010, 2009 and 2008, 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.

A. Summary of Accounting Policies

Nature of Business

Chesapeake, incorporated in 1947 in Delaware, is a diversified utility company engaged in regulated energy, unregulated energy and other unregulated businesses. Our regulated energy business delivers natural gas to approximately 120,000 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 396-mile interstate pipeline from various points in Pennsylvania and northern Delaware to our natural gas distribution affiliates in Delaware and Maryland as well as to other utility and industrial customers in Pennsylvania, Delaware and the Eastern Shore of Maryland.

Our unregulated energy business includes natural gas marketing, propane distribution and propane wholesale marketing operations. The natural gas marketing operation sells natural gas supplies directly to commercial and industrial customers in Florida, Delaware and Maryland. Through our propane distribution operation, we distribute propane to approximately 48,000 customers in Delaware, the Eastern Shore of Maryland and Virginia, southeastern Pennsylvania and Florida. The propane wholesale marketing operation markets propane to wholesale customers including large independent oil and petrochemical companies, resellers and propane distribution companies in the southeastern United States.

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

Principles of Consolidation

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

System of Accounts

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by 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.

Reclassifications

We reclassified certain amounts in the consolidated balance sheet as of December 31, 2009 and in the consolidated statements of cash flows for the years ended December 31, 2009 and 2008 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

Use of Estimates

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

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 owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. The provision for depreciation is computed using the straight-line method at rates that amortize the unrecovered cost of depreciable property over the estimated remaining useful life of the asset. Depreciation and amortization expenses for the regulated energy operations are provided at various annual rates, as approved by the regulators.

	December 31, 2010	December 31, 2009	Useful Life [1]
(In thousands)			
Plant in service			
Mains	**$259,672**	$236,352	27-62 years
Services — utility	**68,349**	65,070	12-48 years
Compressor station equipment	**24,952**	24,981	42 years
Liquified petroleum gas equipment	**27,623**	28,240	5-31 years
Meters and meter installations	**32,850**	28,419	Unregulated energy 3-33 years, regulated energy 14-49 years
Measuring and regulating station equipment	**22,332**	17,708	14-54 years
Office furniture and equipment	**15,796**	15,532	Unregulated energy 4-7 years, regulated energy 14-25 years
Transportation equipment	**17,046**	16,613	1-20 years
Structures and improvements	**16,290**	15,184	3-44 years [2]
Land and land rights	**15,052**	12,789	Not depreciable, except certain regulated assets
Propane bulk plants and tanks	**7,967**	7,275	12-40 years
Electric transmission lines and transformers	**30,669**	29,024	10-41 years
Poles and towers	**9,259**	8,434	21-40 years
Other equipment	**9,189**	11,147	10-61 years
Various	**21,945**	22,676	Various
Total plant in service	**578,991**	539,444	
Plus construction work in progress	**5,394**	4,461	
Less accumulated depreciation	**(121,628)**	(107,318)	
Net property, plant and equipment	**$462,757**	$436,587	

(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 $146,000 at December 31, 2010.

Cash and Cash Equivalents

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

Inventories

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

Regulatory Assets, Liabilities and Expenditures

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

Notes to the Consolidated Financial Statements

At December 31, 2010 and 2009, 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.

	December 31, 2010	December 31, 2009
(in thousands)		
Regulatory Assets		
Underrecovered purchased fuel costs	**$-**	$368
Income tax related amounts due from customers	**1,897**	2,022
Deferred post retirement benefits	**8,304**	3,636
Deferred transaction and transition costs	**1,264**	1,486
Deferred conversion and development costs	**2,069**	2,720
Environmental regulatory assets and expenditures	**6,826**	7,510
Acquisition adjustment (1)	**764**	795
Loss on reacquired debt(3)	**1,668**	154
Other	**1,143**	1,857
Total Regulatory Assets	**$23,935**	$20,548
Regulatory Liabilities		
Self insurance	**$1,265**	$1,152
Overrecovered purchased fuel costs	**8,159**	6,523
Shared interruptible margins	**-**	84
Conservation cost recovery	**320**	1,060
Rate refund(2)	**-**	258
Income tax related amounts due to customers	**48**	74
Storm reserve	**2,682**	2,554
Accrued asset removal cost	**35,092**	33,214
Other	**269**	983
Total Regulatory Liabilities	**$47,835**	$45,902

(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.

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

We have deferred certain costs as regulatory assets prior to obtaining specific regulatory approvals. We have deferred $1.3 million and $1.5 million, of FPU merger-related costs at December 31, 2010 and 2009, respectively, as deferred transaction and transition costs above, which represent our estimate, based on similar proceedings in Florida in the past, of the merger-related costs which we expect to be permitted to recover when we complete the appropriate proceedings. We are currently in the process of discussing this recovery with the Office of Public Counsel. Also included in income tax related amounts due from customers are $1.2 million and $838,000 at December 31, 2010 and 2009, respectively, for which we are currently seeking recovery in the rate case. With the exception of purchased fuel costs and deferred conversion and development costs, there are no material regulatory assets for which we have not earned the appropriate rate of return.

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 the 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.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent increase in the discount rate could decrease our pension and postretirement costs by approximately $98,000 and a decrease of 0.25 percent could increase our pension and postretirement costs by $123,000. A 0.25 percent increase in the rate of return would decrease our pension cost by approximately $112,000, and a decrease of 0.25 percent could increase our pension cost by approximately $117,000 and will not have an impact on postretirement and SERP plans because these plans are not funded.

Income Taxes and Investment Tax Credit Adjustments

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

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

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 statements of income in the period of change. There were unrealized gains of $284,000 in 2010 and unrealized losses of $1.6 million in 2009. Trading liabilities are recorded as mark-to-market energy liabilities. Trading assets are recorded as mark-to-market energy assets.

Our natural gas, electric and propane distribution operations and natural gas marketing operations 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. 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 2010 and 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 $168,000 and $41,000, respectively. At both December 31, 2010 and 2009, the fair value of the put options was $0.

Notes to the Consolidated Financial Statements

Earnings Per Share

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

For the Years Ended December 31,	2010	2009	2008
(in thousands, except shares and per share data)			
Calculation of Basic Earnings Per Share:			
Net Income	$26,056	$15,897	$13,607
Weighted average shares outstanding	9,474,554	7,313,320	6,811,848
Basic Earnings Per Share	$2.75	$2.17	$2.00
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	$26,056	$15,897	$13,607
Effect of 8.25% Convertible debentures	73	79	89
Adjusted numerator — Diluted	$26,129	$15,976	$13,696
Reconciliation of Denominator:			
Weighted shares outstanding — Basic	9,474,554	7,313,320	6,811,848
Effect of dilutive securities:			
Share-based Compensation	22,550	34,229	12,083
8.25% Convertible debentures	85,270	92,652	103,552
Adjusted denominator — Diluted	9,582,374	7,440,201	6,927,483
Diluted Earnings Per Share	$2.73	$2.15	$1.98

Common stock issued in connection with the FPU merger (See Note B, "Acquisitions," to the Consolidated Financial Statements) increased weighted average shares outstanding during 2010 and 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 an alternative to negotiated rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. In connection with this accrual, we must estimate 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.

Notes to the Consolidated Financial Statements

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

Each of our natural gas distribution operations in Delaware and Maryland, our FPU natural gas operation and 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. Chesapeake's Florida natural gas distribution division provides only unbundled delivery service.

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

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

Cost of Sales

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

Operations and Maintenance Expenses

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

Depreciation and Accretion Included in Operations Expenses

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

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.

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. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature of the assets and liabilities and the regulatory mechanism for recovery, to which these assets and liabilities are subject, 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 our value of net assets and future earnings.

Total value of the consideration transferred by Chesapeake in the FPU merger was $75.7 million. Net fair value of the assets acquired and liabilities assumed in the FPU merger was estimated to be $41.5 million. This resulted in a purchase premium of $34.2 million, which was reflected as goodwill. Note B, "Acquisitions," to the Consolidated Financial Statements describes more fully the purchase price allocation.

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

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Amendments Yet to be Adopted by the Company

In 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 our financial statements in accordance with IFRS as early as 2015. 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 our rate-regulated businesses are subject. Throughout 2010, IASB has continued its deliberation on the exposure draft and comments received on the overall concept of the recognition of assets and liabilities arising out of cost-of-service regulation. We will continue to monitor the development of the potential implementation of IFRS.

Other Accounting Amendments Adopted by the Company in 2010

In January 2010, the FASB issued FASB Accounting Standards Update ("ASU") 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements." This ASU requires certain new disclosures and clarifies certain existing disclosure requirements about fair value measurement, as set forth in FASB 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 separate information about purchases, sales, issuances, and settlements. In addition, ASU 2010-06 clarifies certain requirements of the existing disclosures. We adopted the disclosures required by this ASU in the first quarter of 2010, 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 currently do not have any assets or liabilities that would require Level 3 fair value measurements. Adoption of this ASU did not have an impact on our consolidated financial position and results of operations and cash flows.

In April 2010, the FASB issued FASB ASU 2010-12 – Income Taxes (Topic 740), "Accounting for Certain Tax effects of the 2010 Health Care Reform Acts." This ASU codifies the SEC staff announcement relating to the accounting for the Health Care and Education Reconciliation Act and the Patient Protection and Affordable Care Act, which allows the two Acts to be considered together for accounting purposes. We adopted this ASU in the first quarter of 2010 and have determined that these Acts did not have a material impact on our income tax accounting (see Note M, "Employee Benefit Plans," to the Consolidated Financial Statements for further discussion).

B. Acquisitions

FPU

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

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 Florida operations. As a result of the merger, we also now serve 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 was no contingent consideration in the merger. The total value of consideration transferred by Chesapeake in the merger was approximately $75.7 million.

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

The following table summarizes the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of the merger.

	October 28, 2009
(In thousands)	
Purchase price	$ 75,699
Current assets	26,761
Property, plant and equipment	139,709
Regulatory assets	19,899
Investments and other deferred charges	3,659
Intangible assets	4,019
Total assets acquired	194,047
Long term debt	47,812
Borrowings from line of credit	4,249
Other current liabilities	17,427
Pre-merger contingencies	923
Other regulatory liabilities	19,414
Pension and post retirement obligations	14,276
Environmental liabilities	12,414
Deferred income taxes	20,559
Customer deposits and other liabilities	15,467
Total liabilities assumed	152,541
Net identifiable assets acquired	41,506
Goodwill	$ 34,193

During 2010, we adjusted the allocation of the purchase price based on additional information available. The adjustments are related to certain accruals, regulatory assets, deferred and current income tax assets and liabilities, and pre-merger contingencies (see discussion below). These adjustments also resulted in a change in fair value of the propane property, plant and equipment. Goodwill from the merger increased to $34.2 million after incorporating these adjustments, compared to $33.4 million as previously disclosed at December 31, 2009.

None of the $34.2 million in goodwill recorded in connection with the merger 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 to the synergies and opportunities primarily related to FPU's regulated energy businesses. The intangible assets acquired in connection with the merger are related to propane customer list ($3.5 million) and favorable propane supply contracts ($519,000). The intangible value assigned to FPU's existing propane customer list is being amortized over a 12-year period based on the expected duration of the benefit arising from the list. The intangible value assigned to FPU's favorable propane contracts is being amortized over a period ranging from one to 14 months based on contractual terms.

Current assets of $26.8 million acquired during the merger included notes receivable of approximately $5.8 million, for which we received full payment in March 2010, and accounts receivable of approximately $3.1 million, $6.0 million and $891,000 for FPU's natural gas, electric and propane distribution businesses, respectively.

Notes to the Consolidated Financial Statements

The pre-merger contingencies of $923,000 included in the final allocation of the purchase price are primarily related to a pending settlement agreement for a class action complaint against FPU from a propane customer, which is further discussed in Note Q, "Other Commitments and Contingencies" to the Consolidated Financial Statements. The proposed settlement addresses a particular charge by FPU to its propane customers during the period from May 27, 2006 to September 24, 2010, which encompasses both pre-merger and post-merger periods. We used the ratio of the charges assessed to customers during the pre-merger period to the charges assessed to customers during the total settlement period to estimate that $835,000 of the total contingency was related to FPU's operations prior to the merger with Chesapeake. The portion of the liability related to FPU's operations after the merger with Chesapeake and any increases to the liability after the measurement date, which totaled to $370,000, was expensed in 2010. Also included in the pre-merger contingencies are liabilities related to FPU's income taxes for periods prior to the merger.

The financial position and results of operations and cash flows of FPU from the effective date of the merger are included in our consolidated financial statements. The revenue from FPU for the years December 31, 2010 and 2009, included in our consolidated statements of income, were $180.2 million and $26.4 million, respectively, and the net income from FPU for the years ended December 31, 2010 and 2009, included in our consolidated statements of income, were $9.3 million and $1.8 million, respectively.

The following table shows the actual results of combined operations for the year ended December 31, 2010 and pro forma results of combined operations for the year ended December 31, 2009, as if the merger had been completed at January 1, 2009. Since the effects of the merger for the year ended December 31, 2010 were already included in the actual results of our consolidated operations, there is no pro forma adjustment for the year ended December 31, 2010.

For the Years Ended December 31,	2010	2009
(in thousands, except per share data)		
Operating revenues	**$427,546**	$394,772
Operating Income	**$51,930**	$44,382
Net Income	**$26,056**	$20,872
Earnings per share - basic	**$2.75**	$2.23
Earnings per share- diluted	**$2.73**	$2.20

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

The acquisition method of accounting requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger. 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 the proper accounting treatment for the merger-related costs. As of December 31, 2010, we incurred approximately $3.3 million in costs to consummate the merger, including the cost associated with merger-related litigation and integrating operations following the merger. This includes $369,000 incurred during the year ended December 31, 2010. We deferred approximately $1.3 million of the total costs incurred as a regulatory asset at December 31, 2010, 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.

Included in the $3.3 million merger-related costs incurred as of December 31, 2010, were approximately $452,000 of severance and other restructuring charges for our efforts to integrate the operations of the two companies.

Virginia LP Gas

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

Indiantown Gas Company

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

C. Segment Information

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

- *Regulated Energy.* The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the 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 subsidiary, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

The following table presents information about our reportable segments.

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$268,830**	$137,847	$115,544
Unregulated Energy	**146,430**	119,719	161,287
Other	**12,286**	11,219	14,612
Total operating revenues, unaffiliated customers	**$427,546**	$268,785	$291,443
Intersegment Revenues [1]			
Regulated Energy	**$1,104**	$1,252	$924
Unregulated Energy	**363**	254	3
Other	**856**	779	761
Total intersegment revenues	**$2,323**	$2,285	$1,688
Operating Income			
Regulated Energy	**$43,509**	$26,900	$24,733
Unregulated Energy	**7,908**	8,158	3,781
Other	**513**	(1,322)	(35)
Operating Income	**51,930**	33,736	28,479
Other income	**195**	165	103
Interest charges	**9,146**	7,086	6,158
Income taxes	**16,923**	10,918	8,817
Net income from continuing operations	**$26,056**	$15,897	$13,607
Depreciation and Amortization			
Regulated Energy	**$17,038**	$8,866	$6,694
Unregulated Energy	**3,433**	2,415	2,024
Other and eliminations	**287**	307	287
Total depreciation and amortization	**$20,758**	$11,588	$9,005
Capital Expenditures			
Regulated Energy	**$41,898**	$22,917	$25,386
Unregulated Energy	**2,764**	1,873	3,417
Other	**2,293**	1,504	2,041
Total capital expenditures	**$46,955**	$26,294	$30,844

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

At December 31,	2010	2009
Identifiable Assets		
Regulated Energy	**$520,192**	$481,606
Unregulated Energy	**113,039**	99,642
Other	**37,762**	34,286
Total identifiable assets	**$670,993**	$615,534

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, 2010, 2009 and 2008 were as follows:

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Cash paid for interest	**$8,751**	$6,703	$5,835
Cash paid for income taxes	**$10,168**	$1,111	$3,885

Non-cash investing and financing activities during the years ended December 31, 2010, 2009, and 2008 were as follows:

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Capital property and equipment acquired on account, but not paid as of December 31	**$1,064**	$1,151	$696
Merger/acquisitions	**$300**	$75,682	-
Retirement Savings Plan	**$902**	$982	$159
Dividend Reinvestment Plan	**$1,182**	$692	$208
Conversion of Debentures	**$202**	$135	$177
Performance Incentive Plan	**$719**	-	$568
Director Stock Compensation Plan	**$297**	$214	$181
Tax benefit on stock warrants and share-based compensation	**$253**	-	$50

E. DERIVATIVE INSTRUMENTS

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas and propane. Our natural gas and propane distribution operations have entered into agreements with suppliers to purchase natural gas and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered "normal purchases and sales" and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2010, our natural gas and propane distribution operations did not have any outstanding derivative contracts.

Xeron, our propane wholesale and marketing operation, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of December 31, 2010, we had the following outstanding trading contracts which we accounted for as derivatives:

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

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire by the end of the second quarter of 2011.

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

Fair values of the derivative contracts recorded in the Consolidated Balance Sheets as of December 31, 2010 and 2009, are the following:

		Asset Derivatives	
		Fair Value	
(in thousands)	Balance Sheet Location	December 31, 2010	December 31, 2009
Derivatives not designated as hedging instruments:			
Forward contracts	Mark-to-market energy assets	\$1,642	\$2,379
Put Option[(1)(2)]	Mark-to-market energy assets	-	-
Total asset derivatives		\$1,642	\$2,379

		Liability Derivatives	
		Fair Value	
(in thousands)	Balance Sheet Location	December 31, 2010	December 31, 2009
Derivatives not designated as hedging instruments:			
Forward contracts	Mark-to-market energy liabilities	\$1,492	\$2,514
Total liability derivatives		\$1,492	\$2,514

(1) We purchased a put option for the Pro-Cap (propane price cap) Plan in October 2010. The put option which expires in January and February 2011 had a fair value of \$0 at December 31, 2010.
(2) We purchased a put option for the Pro-Cap Plan in September 2009. The put option, which expired on March 31, 2010, had a fair value of \$0 at December 31, 2009.

The effects of gains and losses from derivative instruments on the Consolidated Statement of Income are the following:

		Amount of Gain (Loss) on Derivatives:		
	Location of Gain	For the Years Ended December 31,		
(in thousands)	(Loss) on Derivatives	2010	2009	2008
Derivatives designated as fair value hedges:				
Propane swap agreement[1]	Cost of Sales	$-	($42)	$1,476
Derivatives not designated as hedging instruments:				
Put Option[2]	Cost of Sales	(168)	-	-
Put Option[3]	Revenue	-	(41)	-
Unrealized gain (loss) on forward contracts	Revenue	284	(1,565)	1,357
Total		$116	($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 October 2010. The put option, which expires in January and February 2011, had a fair value of $0 at December 31, 2010.

[3] We purchased a put option for the Pro-Cap Plan in September 2009. The put option, which expired on March 31, 2010, had a fair value of $0 at December 31, 2009.

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

		Amount of Trading Revenue		
	Location of Gain	For the Years Ended December 31,		
(in thousands)	(Loss) on Derivatives	2010	2009	2008
Realized gain on forward contracts/put option	Revenue	$1,540	$3,830	$1,935
Unrealized gain (loss) on forward contracts	Revenue	284	(1,565)	1,357
Total		$1,824	$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; and

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

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

		Fair Value Measurements Using:		
(in thousands)	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments	$4,036	$4,036	$-	$-
Mark-to-market energy assets	$1,642	$-	$1,642	$-
Liabilities:				
Mark-to-market energy liabilities	$1,492	$-	$1,492	$-

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	$2,379	$-	$2,379	$-
Liabilities:				
Mark-to-market energy liabilities	$2,514	$-	$2,514	$-

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of December 31, 2010 and 2009:

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, 2010, 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, 2010, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $98.9 million, compared to a fair value of $113.4 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, 2009, the estimated fair value was approximately $145.5 million, compared to a carrying value of $134.1 million.

G. INVESTMENTS

The investment balance at December 31, 2010, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan; (b) a Rabbi Trust related to a stay bonus agreement with a former executive; and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. 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, 2010 and 2009, total investments had a fair value of $4.0 million and $2.0 million, respectively.

H. GOODWILL AND OTHER INTANGIBLE ASSETS

The carrying value of goodwill as of December 31, 2010 and 2009 is as follows:

(in thousands)	December 31, 2010	December 31, 2009
Regulated Energy	$34,939	$33,421
Unregulated Energy	674	674
Total	$35,613	$34,095

Goodwill in the regulated energy segment is comprised of $34.2 million from the FPU merger and $746,000 from the purchase of operating assets from IGC. Goodwill in the unregulated energy segment is comprised of the premium paid by Sharp in its acquisitions in the late 1980s and 1990s.

We test for impairment of goodwill at least annually. The impairment testing for 2010 and 2009 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2010 and 2009 are as follows:

	December 31, 2010		December 31, 2009	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Favorable propane contracts	**$0**	$0	**$519**	$169
Customer list	**3,500**	340	**3,500**	49
Other	**566**	267	**379**	229
	$4,066	$607	**$4,398**	$447

Favorable propane contracts and customer list were acquired in the FPU merger in October 2009. All of the favorable propane contracts expired as of December 31, 2010. The propane customer list is amortized over a 12-year period. Other intangible assets include customer lists and a non-compete agreement acquired in the purchase of the operating assets of Virginia LP Gas, Inc. in February 2010 and customer lists and acquisition costs from our acquisitions in the late 1980s and 1990s. These intangible assets are amortized over a period ranging from seven to 40 years.

For the years ended December 31, 2010, 2009 and 2008, amortization expense of intangible assets was $679,000, $232,000 and $14,000, respectively. Amortization expense of intangible assets for 2011 to 2015 is: $332,000 for 2011, $329,000 for 2012, $325,000 for 2013-2015.

I. Income Taxes

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. FPU has been included in the Company's consolidated federal return since the completion of the merger on October 28, 2009. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. FPU will continue to file a separate state income tax return in Florida.

In September 2008, the Internal Revenue Service ("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 IRS 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, 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, 2010, we have no remaining carryforward of the 2008 federal tax net operating loss. As of December 31, 2010, we also had tax net operating losses from various states totaling $16.6 million, almost all of which will expire in 2027. We have recorded a deferred tax asset of $1.3 million 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.

Notes to the Consolidated Financial Statements

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, 2010 and 2009.

For the Years Ended December 31,		2010	2009	2008
(in thousands)				
Current Income Tax Expense				
	Federal	**$1,566**	$-	($2,551)
	State	**2,116**	878	-
	Investment tax credit adjustments, net	**(91)**	(69)	(42)
Total current income tax expense (benefit)		**3,591**	809	(2,593)
Deferred Income Tax Expense (1)				
	Property, plant and equipment	**16,964**	7,098	10,272
	Deferred gas costs	**(2,505)**	(786)	781
	Pensions and other employee benefits	**(402)**	(612)	(174)
	Amortization of intangibles	**(211)**	5	75
	Environmental expenditures	**32**	7	145
	Net operating loss carryforwards	**99**	4,106	-
	Merger related costs	**(13)**	967	-
	Reserve for insurance deductibles	**(419)**	518	462
	Other	**(213)**	(1,194)	(151)
Total deferred income tax expense (benefit)		**13,332**	10,109	11,410
Total Income Tax Expense		**$16,923**	$10,918	$8,817
Reconciliation of Effective Income Tax Rates				
Continuing Operations				
	Federal income tax expense (2)	**$15,053**	$9,171	$7,863
	State income taxes, net of federal benefit	**2,083**	1,490	1,162
	Merger related costs	**70**	299	-
	ESOP dividend deduction	**(266)**	(213)	(205)
	Other	**(17)**	171	(3)
Total income tax expense		**$16,923**	$10,918	$8,817
Effective income tax rate		**39.38%**	40.72%	39.32%

At December 31,			2010	2009
(in thousands)				
Deferred Income Taxes				
	Deferred income tax liabilities:			
		Property, plant and equipment	**$89,544**	$75,863
		Deferred gas costs	-	848
		Loss on reacquired debt	**643**	59
		Other	**2,891**	2,884
	Total deferred income tax liabilities		**93,078**	79,654
	Deferred income tax assets:			
		Pension and other employee benefits	**7,849**	7,972
		Environmental costs	**1,770**	1,803
		Net operating loss carryforwards	**1,300**	305
		Self insurance	**419**	464
		Storm reserve liability	**1,034**	985
		Other	**2,866**	2,841
	Total deferred income tax assets		**15,238**	14,370
Deferred Income Taxes Per Consolidated Balance Sheet			**$77,840**	$65,284

(1) Includes $1,963,000, $1,588,000 and $260,000 of deferred state income taxes for the years 2010, 2009 and 2008, respectively.

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

J. LONG-TERM DEBT

Our outstanding long-term debt is as shown below.

	December 31, 2010	December 31, 2009
(in thousands)		
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$7,248**	$8,156
10.03% bond, due May 1, 2018	**3,986**	4,486
9.08% bond, due June 1, 2022	**7,950**	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
6.85% note, due January 1, 2012	**1,000**	2,000
7.83% note, due January 1, 2015	**8,000**	10,000
6.64% note, due October 31, 2017	**19,091**	21,818
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	**1,318**	1,520
Promissory note	**265**	40
Total long-term debt	**98,858**	134,113
Less: current maturities	**(9,216)**	(35,299)
Total long-term debt, net of current maturities	**$89,642**	$98,814

Annual maturities of consolidated long-term debt are as follows: $9,216 for 2011; $8,196 for 2012; $8,196 for 2013; $12,514 for 2014; $9,141 for 2015 and $51,685 thereafter.

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 are guaranteed by Chesapeake and are secured by a lien covering all of FPU's property. The 9.57 percent bond and 10.03 percent bond require annual sinking fund payments of $909,000 and $500,000, respectively.

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 maturities. 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. We are amortizing this difference over the remaining terms of these bonds as adjustments to interest expense as allowed by the Florida PSC.

Uncollateralized Senior Notes

On June 29, 2010, we entered into an agreement with Metropolitan Life Insurance Company and New England Life Insurance Company to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU bonds. The terms of the agreement require us to issue $29 million of the $36 million in uncollateralized senior notes committed by the lender on or before July 9, 2012, with a 15-year term at a rate ranging from 5.28 percent to 6.13 percent based on the timing of the issuance. The remaining $7 million will be issued prior to May 3, 2013, at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance. These notes, when issued, will have similar covenants and default provisions as the existing senior notes and will have an annual principal payment beginning in the sixth year after the issuance.

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 2010 and 2009, debentures totaling $202,000 and $135,000, 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 2010 and 2009, no debentures were redeemed for cash. At our 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 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, 2010, we are in compliance with all of our debt covenants. With the redemption of FPU's 6.85 percent and 4.90 percent secured first mortgage bonds in January 2010, the additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth was met.

Each of Chesapeake's uncollateralized senior notes contains a "Restricted Payments" covenant as defined in the note agreements. The most restrictive covenants of this type are included within the 7.83 percent Unsecured Senior Notes, due January 1, 2015. The covenant provides that we cannot pay or declare any dividends or make any other Restricted Payments (such as dividends) in excess of the sum of $10.0 million, plus our consolidated net income accrued on and after January 1, 2001. As of December 31, 2010, the cumulative consolidated net income base was $128.9 million, offset by Restricted Payments of $76.2 million, leaving $52.7 million of cumulative net income free of restrictions.

Each series of FPU's first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which provides that FPU cannot make dividend or other restricted payments in excess of the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2010, FPU's cumulative net income base was $65.9 million, offset by restricted payments of $37.6 million, leaving $28.3 million of cumulative net income for FPU free of restrictions pursuant to this covenant. In January 2010, this series of first mortgage bonds was redeemed prior to its maturity.

K. SHORT-TERM BORROWING

At December 31, 2010 and 2009, we had $64.0 million and $30.0 million, respectively, of short-term borrowings outstanding. The annual weighted average interest rates on our short-term borrowings were 1.77 percent and 1.28 percent for 2010 and 2009, respectively. We incurred commitment fees of $86,000 and $79,000 in 2010 and 2009, respectively.

The outstanding short-term borrowings at December 31, 2010 were composed of $30.8 million in borrowings from the bank lines of credit, $29.1 million in borrowings from a term loan maturing in March 2011 and $4.1 million in book overdrafts representing outstanding checks in excess of funds on deposit, which if presented would be funded through the bank lines of credit. All of the outstanding short-term borrowings at December 31, 2009 were related to the bank lines of credit.

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

Committed credit facilities
As of December 31, 2010 we had two committed revolving credit facilities totaling $60.0 million. The first facility is an unsecured $30.0 million revolving line of credit that bears interest at the respective LIBOR rate, plus 1.25 percent per annum. At December 31, 2010, there were no available funds under this credit facility.

The second facility is a $30.0 million committed revolving line of credit that bears interest at a base rate plus 1.25 percent, if requested and advanced on the same day, or LIBOR for the applicable period plus 1.25 percent if requested three days prior to the advance date. At December 31, 2010, there was $29.5 million available under this credit facility.

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

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

We are in compliance with all of our debt covenants.

Uncommitted credit facilities
As of December 31, 2010, we had two uncommitted lines of credit facilities totaling $40.0 million. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks.

The first facility is an uncommitted $20.0 million line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. At December 31, 2010, the entire borrowing capacity of $20.0 million was available under this credit facility.

The second facility is a $20.0 million uncommitted line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. We have issued $3.2 million in letters of credit under this credit facility. There have been no draws on these letters of credit as of December 31, 2010. We do not anticipate that the letters of credit will be drawn upon by the counterparties and we expect that the letters of credit will be renewed to the extent necessary in the future. At December 31, 2010, there was $16.8 million available under this credit facility which was reduced by $3.2 million for letters of credit issued.

In addition to the four unsecured bank lines of credit, we entered into a new term loan for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility related to the early redemption of the 6.85 percent and 4.90 percent series of FPU's secured first mortgage bonds prior to their respective maturities. The interest rate on the borrowing was fixed at 1.88 percent for nine months and on December 16, 2010 the rate was fixed for three months at 1.55%. On November 1, 2010 we extended the maturity of this credit facility from March 15, 2011 until October 31, 2011. We are subject to the same covenants representations and warranties for this term loan facility as we are for the $20 million second uncommitted line of credit facility.

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.

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 $1.1 million, $997,000 and $880,000 for 2010, 2009 and 2008, respectively. Future minimum payments under our current lease agreements are $803,000, $717,000, $517,000, $377,000 and $93,000 for the years 2011 through 2015, respectively; and $2.0 million thereafter, with an aggregate total of $4.5 million.

M. EMPLOYEE BENEFIT PLANS

Retirement Plans

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

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

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive income/loss or as a regulatory asset as of December 31, 2010:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	($11)	$-	$83	$-	$-	$72
Net loss	3,221	1,409	793	1,145	531	7,099
Total unrecognized cost	$3,210	$1,409	$876	$1,145	$531	$7,171
Accumulated other comprehesive loss pre-tax[1]	$3,210	$268	$876	$1,145	$101	$5,600
Regulatory asset post merger	-	1,141	-	-	430	1,571
Subtotal	3,210	1,409	876	1,145	531	7,171
Regulatory asset pre-merger	-	6,631	-	-	78	6,709
Total	$3,210	$8,040	$876	$1,145	$609	$13,880

[1]The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2010 is net of income tax benefits of $2.2 million.

The pre-merger regulatory asset of $6.7 million at December 31, 2010 represents the portion attributable to FPU's regulated energy operations of the changes in the funded status in the FPU Pension Plan and FPU Medical Plan that occurred but were not recognized as part of the net periodic benefit costs prior to the merger. This portion was deferred as a regulatory asset prior to the merger by FPU pursuant to a previous order by the Florida PSC and continues to be amortized over the remaining service period of the participants at the time of the merger.

The amounts in accumulated other comprehensive income/loss and regulatory asset for our pension and postretirement benefits plans that are expected to be recognized as a component of net benefit cost in 2011 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	$173	$-	$43	$58	$22	$296
Amortization of pre-merger regulatory asset	$-	$761	$-	$-	$8	$769

In January 2011, our former Chief Executive Officer, John Schimkaitis, retired and received a lump-sum pension distribution of $844,000 from the Chesapeake Pension Plan. He is also expected to receive $765,000 in the form of a lump-sum distribution from the Chesapeake SERP in July 2011. In connection with these lump-sum payment distributions, we expect to record $455,000 in pension settlement losses which will be recorded in addition to the net benefit cost in 2011. Based upon the current funding status of the Chesapeake Pension Plan, which does not meet or exceed 110 percent of the benefit obligation as required per the regulations, Mr. Schimkaitis was required to deposit property equal to 125 percent of the restricted portion of his lump sum distribution into an escrow. Each year, an amount equal to the value of payments that would have been paid to him if he had elected the life annuity form of distribution will become unrestricted. Property equal to the life annuity amount will be returned to him from the escrow account. These same regulations will apply to the top 20 highest compensated employees taking distributions from the Pension Plan.

Defined Benefit Pension Plans

The Chesapeake Pension Plan was closed to new participants effective January 1, 1999 and was frozen with respect to additional years of service 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.

The following schedule summarizes the assets of the Chesapeake Pension Plan, by investment type, at December 31, 2010, 2009 and 2008 and the assets of the FPU Pension Plan, by investment type, at December 31, 2010 and 2009:

	Chesapeake Pension Plan			FPU Pension Plan	
At December 31,	**2010**	**2009**	**2008**	**2010**	**2009**
Asset Category					
Equity securities	**64.33%**	66.22%	48.70%	**60.00%**	63.00%
Debt securities	**30.60%**	33.76%	51.24%	**35.00%**	29.00%
Other	**5.07%**	0.02%	0.06%	**5.00%**	8.00%
Total	**100.00%**	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 equity securities held by the Chesapeake Pension Plan as of December 31, 2010 and 2009 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. All of the debt securities and other assets held by the Chesapeake Pension Plan as of December 31, 2010 and 2009 are classified under Level 2 of the fair value hierarchy and are recorded at fair value based on quoted market prices in active markets for similar assets or closing prices reported in active markets for those assets. All of the assets held by the FPU Pension Plan as of December 31, 2010 and 2009 are also classified under Level 2 of the fair value hierarchy and are recorded at fair value based on net asset value per unit of those assets.

The 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 Chesapeake Pension 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 FPU Pension 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 also made under the direction of the Employee Benefits Committee.

Notes to the Consolidated Financial Statements

The following schedule sets forth the funded status at December 31, 2010 and 2009:

At December 31,	Chesapeake Pension Plan 2010	Chesapeake Pension Plan 2009	FPU Pension Plan 2010	FPU Pension Plan 2009
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year [1]	**$11,127**	$11,593	**$45,420**	$46,851
Interest cost	**570**	547	**2,729**	418
Change in assumptions	**(5)**	(188)	**-**	-
Actuarial loss	**776**	(307)	**6,326**	(1,544)
Benefits paid	**(708)**	(518)	**(1,997)**	(305)
Benefit obligation — end of year	**11,760**	11,127	**52,478**	45,420
Change in plan assets:				
Fair value of plan assets — beginning of year [1]	**7,449**	6,689	**36,427**	35,037
Actual return on plan assets	**490**	1,278	**4,605**	1,695
Employer contributions	**556**	-	**1,166**	
Benefits paid	**(708)**	(518)	**(1,997)**	(305)
Fair value of plan assets — end of year	**7,787**	7,449	**40,201**	36,427
Reconciliation:				
Funded status	**(3,973)**	(3,678)	**(12,277)**	(8,993)
Accrued pension cost	**($3,973)**	($3,678)	**($12,277)**	($8,993)
Assumptions:				
Discount rate	**5.00%**	5.25%	**5.25%**	5.75%
Expected return on plan assets	**6.00%**	6.00%	**7.00%**	7.00%

[1]FPU Pension Plan's beginning balance for 2009 reflects the benefit obligations as of the merger date of October 28, 2009.

Net periodic pension cost (benefit) for the plans for 2010, 2009, and 2008 include the components shown below:

For the Years Ended December 31,	Chesapeake 2010	Chesapeake 2009	Chesapeake 2008	FPU 2010	FPU 2009 [1]
(In thousands)					
Components of net periodic pension cost:					
Interest cost	**$570**	$547	$594	**$2,729**	$418
Expected return on assets	**(423)**	(362)	(629)	**(2,532)**	(396)
Amortization of prior service cost	**(5)**	(5)	(5)	**-**	-
Amortization of actuarial loss	**155**	237	-	**-**	-
Net periodic pension benefit	**$297**	$417	($40)	**$197**	$22
Assumptions:					
Discount rate	**5.25%**	5.25%	5.50%	**5.75%**	5.50%
Expected return on plan assets	**6.00%**	6.00%	6.00%	**7.00%**	7.00%

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

In addition, we recorded $888,000 in expense in 2010 related to continued amortization of FPU's pre-merger pension regulatory asset.

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 $2.7 million and $2.5 million, at December 31, 2010 and 2009, respectively.

At December 31,	2010	2009
(in thousands)		
Change in benefit obligation:		
Benefit obligation — beginning of year	**$2,505**	$2,520
Interest cost	**136**	129
Actuarial (gain) loss	**179**	(55)
Amendments	**-**	-
Benefits paid	**(89)**	(89)
Benefit obligation — end of year	**2,731**	2,505
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	**(2,731)**	(2,505)
Accrued pension cost	**($2,731)**	($2,505)
Assumptions:		
Discount rate	**5.00%**	5.25%

Net periodic pension costs for the Chesapeake Pension SERP for 2010, 2009, and 2008 include the components shown below:

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Components of net periodic pension cost:			
Interest cost	**$136**	$130	$125
Amortization of prior service cost	**18**	18	-
Amortization of actuarial loss	**59**	54	45
Net periodic pension cost	**$213**	$202	$170
Assumptions:			
Discount rate	**5.25%**	5.25%	5.50%

Notes to the Consolidated Financial Statements

Other Postretirement Benefits Plans

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

At December 31,	Chesapeake Postretirement Plan 2010	2009	FPU Medical Plan 2010	2009
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year [1]	**$2,585**	$2,179	**$2,417**	$2,457
Service cost	**-**	3	**76**	18
Interest cost	**121**	131	**122**	23
Plan participants contributions	**100**	90	**-**	6
Actuarial (gain) loss	**(149)**	378	**595**	(71)
Benefits paid	**(183)**	(196)	**(112)**	(16)
Benefit obligation — end of year	**2,474**	2,585	**3,098**	2,417
Change in plan assets:				
Fair value of plan assets — beginning of year [1]	**-**	-	**-**	-
Employer contributions[2]	**83**	106	**112**	10
Plan participants contributions	**100**	90	**-**	6
Benefits paid	**(183)**	(196)	**(112)**	(16)
Fair value of plan assets — end of year	**-**	-	**-**	-
Reconciliation:				
Funded status	**(2,474)**	(2,585)	**(3,098)**	(2,417)
Accrued postretirement cost	**($2,474)**	($2,585)	**($3,098)**	($2,417)
Assumptions:				
Discount rate	**5.00%**	5.25%	**5.25%**	5.75%

[1] FPU Medical Plan's beginning balance for 2009 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 benefit costs for 2010, 2009, and 2008 include the following components:

For the Years Ended December 31,	Chesapeake Postretirement Plan 2010	2009	2008	FPU Medical Plan 2010	2009 [1]
(in thousands)					
Components of net periodic postretirement cost:					
Service cost	**$-**	$3	$3	**$76**	$18
Interest cost	**122**	131	114	**123**	23
Amortization of:					
Actuarial (gain) loss	**57**	76	290	**(6)**	-
Net periodic postretirement cost	**$179**	$210	$407	**$193**	$41
Assumptions					
Discount rate	**5.25%**	5.25%	5.50%	**5.75%**	5.50%

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

In addition, we recorded $9,000 in expense in 2010 related to continued amortization of FPU's pre-merger postretirement benefit regulatory asset.

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations of all the plans were based on the interest rates of high-quality bonds in 2010, reflecting the expected lives of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake's plans and FPU's plans have different expected lives of the plan and investment policies, 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 increases is not applicable.

The health care inflation rate for 2010 used to calculate the benefit obligation is seven percent for medical and eight 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 $787,000 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 2010 by approximately $48,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $582,000 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 2010 by approximately $40,000.

Estimated Future Benefit Payments

In 2011, we expect to contribute $205,000 and $1.3 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $853,000 to the Chesapeake SERP. We also expect to contribute $96,000 and $158,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2011. The schedule below shows the estimated future benefit payments for each of the plans previously described:

	Chesapeake Pension Plan[1]	FPU Pension Plan[1]	Chesapeake SERP[2]	Chesapeake Postretirement Plan[2]	FPU Medical Plan[2][3]
(in thousands)					
2011	$1,315	$2,324	$853	$96	$158
2012	$465	$2,484	$87	$104	$151
2013	$533	$2,662	$86	$111	$144
2014	$556	$2,815	$84	$119	$169
2015	$686	$2,939	$133	$128	$189
Years 2016 through 2020	$3,932	$15,974	$672	$703	$1,040

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

[2] Benefit payments are expected to be paid out of our general funds.

[3] These amounts are shown net of estimated Medicare Part-D reimbursements of $9,000, $10,000, $11,000, $12,000 and $13,000 for the years 2011 to 2015, respectively, and $78,000 for the years 2015 through 2019.

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

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. Effective January 1, 2011, we match 100 percent of eligible participants' pre-tax contributions to the Chesapeake 401(k) plan up to a maximum of six percent of the eligible compensation, including pre-tax contributions made by BravePoint employees. In addition, we may make a supplemental contribution to all participants in the plan, without regard to whether or not they make pre-tax contributions. Beginning January 1, 2011, the employer matching contribution is made in cash and will be invested based on a participant's investment directions. Any supplemental employer contribution is generally made in Chesapeake stock. With respect to the employer match and supplemental employer contribution participants, employees are 100 percent vested after two years of service or have attained an age of 55 years while still employed by Chesapeake. Employees with one year of service are 20 percent vested and will become 100 percent vested after two years of service. Employees who do not make an election to contribute or do not opt out of the Chesapeake 401(k) plan will be automatically enrolled at a deferral rate of three percent.

Prior to January 1, 2011, we made 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 was 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 was matched with Chesapeake common stock; the remaining match was invested in Chesapeake's 401(k) Plan according to each employee's investment direction. Employees were automatically enrolled at a two-percent contribution, with the option of opting out, and were eligible for the company match after three months of continuing service, with vesting of 20 percent per year.

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

We continue to maintain a separate 401(k) retirement savings plan for FPU. Effective January 1, 2011, we match 100 percent of eligible non-union participants' pre-tax contributions to the FPU 401(k) plan up to a maximum of six percent of the eligible compensation. Eligible employees who have not opted out of the plan are automatically enrolled at the three-percent deferral rate and the automatic deferral will increase by one percent per year up to a maximum of six percent, unless an employee elects otherwise, with vesting of 100 percent after two years of service. Employees with one year of service are 20 percent vested and become 100 percent vested after two years of service. Also, we may make other supplemental employer contributions to the plan at such time that we deem appropriate. Supplemental employer contributions may be made to the eligible plan participants based on the employee compensation for the year. Participants are only eligible for the employer and supplemental employer contributions if they have worked for at least 501 hours and 1000 hours respectfully during the Plan Year.

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

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 $2.4 million and $2.0 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.

Contributions to all of our 401(k) plans totaled $1.7 million for the year ended December 31, 2010 and $1.6 million for both years ended December 31, 2009 and 2008. As of December 31, 2010, there are 582,486 shares reserved to fund future contributions to the 401(k) plans.

Deferred Compensation Plan

On December 7, 2006, the Board of Directors approved the Chesapeake Utilities Corporation Deferred Compensation Plan ("Deferred Compensation Plan"), as amended, effective January 1, 2007. The Deferred Compensation Plan is a non-qualified, deferred compensation arrangement under which certain executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers and fees. At December 31, 2010, the Deferred Compensation Plan consisted solely of shares of common stock related to the deferral of executive performance shares and directors' stock retainers.

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

We established a Rabbi Trust in connection with the Deferred Compensation Plan. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the Balance Sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled $777,000 and $739,000 at December 31, 2010 and 2009, respectively.

N. SHARE-BASED COMPENSATION PLANS

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

The table below presents the amounts included in net income related to share-based compensation expense, for the restricted stock awards issued under the DSCP and the PIP for the years ended December 31, 2010, 2009 and 2008:

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Directors Stock Compensation Plan	**$283**	$191	$180
Performance Incentive Plan	**872**	1,115	640
Total compensation expense	**1,155**	1,306	820
Less: tax benefit	**463**	523	327
Share-Based Compensation amounts included in net income	**$692**	$783	$493

Stock Options

We did not have any stock options outstanding at December 31, 2010 or 2009, nor were any stock options issued during 2010, 2009 and 2008.

Directors Stock Compensation Plan

Under the DSCP, each of our non-employee directors received in 2010 an annual retainer of 900 shares of common stock. Shares granted under the DSCP are issued in advance of the directors' service period; therefore, these shares are fully vested as of the grant date. We record a prepaid expense as of the date of the grant equal to the fair value of the shares issued and amortize the expense equally over a service period of one year.

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

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2008	-	-
Granted[1]	7,174	$29.83
Vested	7,174	$29.83
Forfeited	-	-
Outstanding — December 31, 2009	-	-
Granted	9,900	$29.99
Vested	9,900	$29.99
Forfeited	-	-
Outstanding — December 31, 2010	-	-

[1] On October 28, 2009, we added two new members to our Board of Directors; each new member was awarded 337 shares of common stock for the prorated portion of their service period.

We recorded compensation expense of $283,000, $191,000 and $180,000 related to DSCP awards for the years ended December 31, 2010, 2009 and 2008, respectively.

Notes to the Consolidated Financial Statements

The weighted average grant-date fair value of DSCP awards granted during 2010 and 2009 was $29.99 and $29.83, per share, respectively. The intrinsic values of the DSCP awards are equal to the fair value of these awards on the date of grant. At December 31, 2010, there was $99,000 of unrecognized compensation expense related to DSCP awards that is expected to be recognized over the first four months of 2011.

As of December 31, 2010, there were 34,215 shares reserved for issuance under the 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 successful achievement of long-term goals, growth, and financial results and they are comprised of both market-based and performance-based conditions or targets.

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

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

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2008	94,200	$27.84
Granted	28,875	$29.19
Vested	-	-
Fortfeited	-	-
Expired	-	-
Outstanding — December 31, 2009	123,075	$28.15
Granted	40,875	29.38
Vested	43,960	27.94
Fortfeited	-	-
Expired	18,840	27.94
Outstanding — December 31, 2010	101,150	$28.78

In 2010 and 2008 (in 2009, no shares under the PIP vested), we withheld shares with value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives receiving the net shares. The total number of shares withheld 17,695 and 12,511 for 2010 and 2008, respectively, was based on the value of the PIP shares on their vesting date, determined by the average of the high and low of our stock price. No payments for the employee's tax obligations were made to taxing authorities in 2009 as no shares vested during this period. Total payments for the employees' tax obligations to the taxing authorities were approximately $538,000 and $383,000 in 2010 and 2008, respectively.

We recorded compensation expense of $872,000, $1.1 million and $640,000 related to the PIP for the years ended December 31, 2010, 2009, and 2008, respectively.

The weighted average grant-date fair value of PIP awards granted during 2010, 2009 and 2008 was $29.38, $29.19 and $27.84, per share, respectively. The intrinsic value of the PIP awards was $2.7 million, $2.1 million and $1.1 million for 2010, 2009 and 2008, respectively.

As of December 31, 2010, there were 345,028 shares reserved for issuance under the PIP.

O. RATES AND OTHER REGULATORY ACTIVITIES

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

Delaware

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

At the hearing on March 30, 2010, the Delaware PSC agreed with us that the Delaware division had been releasing capacity based on a previous settlement approved by the Delaware PSC and, therefore, did not require the Delaware division to issue any refunds for past capacity releases. The Delaware PSC, however, required the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO until a more appropriate pricing methodology is developed and approved. The Delaware PSC issued an order on May 18, 2010 elaborating its decisions at the March hearing and directing the parties to reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity releases by the Delaware division to PESCO. On June 17, 2010, the Division of the Public Advocate filed an appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC's decision with regard to refunds for past capacity releases. On June 28, 2010, the Delaware division filed a Notice of Cross Appeal with the Delaware Superior Court asking it to overturn the Delaware PSC's decision with regard to requiring the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO. The parties involved filed opening briefs with the Delaware Superior Court on September 30, 2010, answering briefs on October 20, 2010, and reply briefs on November 3, 2010. We anticipate that the Court will render a decision sometime in 2011. Due to the ongoing legal proceeding, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. We did not accrue any contingent liability related to potential refunds for past capacity releases. Since the Delaware PSC's Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

On September 4, 2009, the 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 evidentiary hearing in this matter was held on May 19, 2010. At the evidentiary hearing, the parties in this docket, which included the Delaware PSC, the Delaware division and the Division of the Public Advocate, presented a proposed settlement agreement to resolve all issues addressed in this docket. The settlement agreement contemplates that the Delaware division will begin to share interruptible margins with its firm ratepayers when those margins reach a certain level in each 12-month period ending October 31. Based on the current level of interruptible margins generated by the Delaware division, we do not anticipate that sharing of future interruptible margins will have a significant impact on our results. The Delaware PSC approved the settlement agreement on September 7, 2010.

On December 17, 2009, the 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. The Delaware PSC granted approval of the Individual Contract Rate on February 18, 2010.

On September 1, 2010, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2010. On September 21, 2010, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2010, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware division anticipates a final decision no later than the third quarter of 2011.

Maryland

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 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 substantially affirming the Hearing Examiner's decision in the matter.

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

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 then 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 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, cost savings and cost increases that have resulted from the merger.

Notes to the Consolidated Financial Statements

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. 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. 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. 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.

In 2010, we recorded a $750,000 accrual related to the regulatory risk for FPU's natural gas distribution operation associated with its earnings, merger benefits and recovery of the purchase premium. We are required to detail known benefits, synergies, cost savings and cost increases resulting from the merger and present the information in the "come-back" filing to the Florida PSC by April 29, 2011 (within 18 months of the merger). We are currently in discussions with the Office of Public Counsel and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings levels as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. We recorded this accrual based on our assessment of FPU's current earnings, the regulatory environment in Florida and progress of the current discussions.

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 Clauses, 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.

On September 1, 2010, FPU's electric distribution operation filed its annual Fuel and Purchased Power Cost Recovery Clause, which seeks final approval of the levelized fuel adjustment and purchased power cost recovery factors for 2011. On December 20, 2010, the Florida PSC issued an order approving the proposed 2011 fuel rates, effective for meters read on and after January 1, 2011.

On September 10, 2010, FPU's electric distribution operation filed its annual Energy Conservation Cost Recovery ("ECCR") Clause, which seeks final approval of the 2009 conservation-related revenues and expenses and new ECCR recovery factors for 2011. On November 29, 2010, the Florida PSC issued an order approving the proposed 2011 ECCR recovery factors, effective for meters read on and after January 1, 2011

On September 13, 2010, Chesapeake's Florida division, FPU's Indiantown division and FPU's natural gas distribution operation separately filed their annual ECCR Clauses, seeking final approval of the 2009 conservation-related revenues and expenses and new ECCR recovery factors for 2011. On November 29, 2010, the Florida PSC issued an order approving all of the proposed 2011 ECCR recovery factors, effective for meters read on or after January 1, 2011.

On September 13, 2010, FPU's natural gas distribution operation filed its annual Purchased Gas Adjustment ("PGA") Clause seeking final approval of its 2009 purchased gas-related revenues and expenses and new PGA cap rate for 2011. On November 29, 2010, the Florida PSC issued an order approving the proposed 2011 PGA cap rate, effective for meters read on or after January 1, 2011.

On, July 7, 2009, the City of Marianna, Florida Commission (the "Commission") passed an ordinance granting a franchise to FPU effective February 1, 2010 for a period not to exceed 10 years for the operation and distribution and/or sale of electric energy (the "franchise agreement"). The franchise agreement provides that FPU will develop and implement new time-of-use ("TOU") and interruptible electric power rates that shall be mutually agreed upon by FPU and the city. The franchise agreement further provides that the TOU and interruptible rates be effective no later than February 17, 2011 and available to all customers within the corporate limits of the City of Marianna. If the rates are not in effect by February 17, 2011, the city has the right to give notice to FPU within 180 days thereafter of its intent to exercise its option to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. If the city elects to purchase the Marianna property, the agreement requires the city to pay FPU the fair market value for such property as determined by three qualified appraisers. If the purchase occurs, FPU would have a gain in the year of the disposition. Additionally, future financial results would be negatively impacted from the loss in earnings generated by FPU under the franchise agreement, however such impact is anticipated to be immaterial.

In accordance with the terms of the franchise agreement, FPU developed reasonable TOU and interruptible rates and on December 14, 2010, filed a petition with the Florida PSC for authority to implement a demonstration project consisting of such proposed TOU and interruptible rates for approval and implementation on or before February 17, 2011. The Florida PSC issued an order approving the proposed TOU and interruptible rates for a four-year period on February 11, 2011. The city has objected to the proposed rates and has filed a petition protesting the entry of the Florida PSC's order.

As disclosed in Item 8 under the heading "Notes to the Consolidated Financial Statements — Note Q, "Other Commitments and Contingencies," on March 2, 2011, the city filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the franchise agreement by FPU and seeking a declaratory judgment that the city has the right to exercise its option to purchase FPU's property in the City of Marianna in accordance with the terms of the franchise agreement.

ESNG

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

Energylink Expansion 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 this project based on increased construction costs over its original projection and initiated billing to recover approximately $3.2 million of costs incurred in connection with this project and the related cost of capital over a period of 20 years in accordance with the terms of the precedent agreements executed with the two participating customers and approved by the FERC. One of the two participating customers is Chesapeake, through its Delaware and Maryland divisions. During 2010, ESNG and the participating customers negotiated to reduce the recovery period of this cost from 20 years to five years. On January 27, 2011, ESNG filed with the FERC the request to amend the cost recovery period, which was approved by the FERC on February 14, 2011.

Mainline Extension Project: On November 25, 2009, ESNG filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 1,594 Mcfs per day of natural gas to Chesapeake's Delaware division. The FERC published the notice of this filing on December 7, 2009. No protest was filed during the 60-day period following the notice, and ESNG commenced construction on February 6, 2010. The facilities were completed on April 29, 2010, and ESNG commenced billing for the new service on May 1, 2010.

Mainline Extension and Interconnect Project: On March 5, 2010, ESNG submitted an Application for Certificate of Public Convenience and Necessity to the FERC related to a proposed mainline extension and interconnect project that would tie into the interstate pipeline system of TETLP. ESNG's project involved building and operating an eight-mile mainline extension from ESNG's existing facility in Parkesburg, Pennsylvania to the interconnection with TETLP at Honey Brook, Pennsylvania. The estimated capital cost of this project is approximately $19.4 million. On September 3, 2010, the FERC approved ESNG's application, subject to certain environmental conditions, some of which had to be met prior to the commencement of construction. ESNG accepted the Order Issuing Certificate on October 4, 2010. On October 13, 2010, the FERC issued a Notice to Proceed with the construction of the project's facilities as all conditions that must be met prior to the commencement of construction were satisfied. The facilities were completed on December 15, 2010, and on December 21, ESNG received FERC approval to place the facilities into service. ESNG commenced billing for the new service on January 1, 2011.

Rate Case Filing: On December 30, 2010, ESNG filed a base rate proceeding in compliance with the terms of the settlement in its prior rate base proceeding. ESNG's filed rates, proposed to be effective February 1, 2011, reflect an annual increase of $6,748,628 over its current rates. The proposed rate increase reflects increases in operating and maintenance expenses, depreciation expense, and return on new gas plant facilities that are expected to be placed into service before June 30, 2011. ESNG proposed a return on equity of 13.5 percent. ESNG expects to reach a settlement agreement on the filing in 2011.

ESNG also had developments in the following FERC matters:

On April 30, 2010, ESNG submitted its annual Interruptible Revenue Sharing Report to the FERC. ESNG reported in this filing that its interruptible revenue was in excess of its annual threshold amount and refunded $90,718, inclusive of interest, in the second quarter of 2010 to its eligible firm customers.

On May 28, 2010, ESNG submitted its annual Fuel Retention Percentage ("FRP") and Cash-Out Surcharge filings to the FERC. In these filings, ESNG proposed to implement a FRP rate of 0.00 percent and a zero rate for its Cash-Out Surcharge. ESNG also proposed to refund $310,117, inclusive of interest, to its eligible customers in the second quarter of 2010 as a result of combining its over-recovered Gas Required for

Operations and its over-recovered Cash-Out Cost. The FERC approved these proposals on June 29, 2010, and ESNG issued refunds to eligible customers.

On August 16, 2010, ESNG submitted its compliance filing with regard to the FERC's Order on Electronic Tariff Filings (Order No. 714). This Order required all natural gas pipelines subject to FERC jurisdiction to file baseline tariff sheets electronically. All subsequent rate and tariff-related filings are to be made electronically. On October 13, 2010, the FERC approved ESNG's compliance filing for this Order.

On September 1, 2010, ESNG submitted its compliance filing with regard to the FERC's most recent Order adopting Standards for Business Practices for Interstate Natural Gas Pipelines (Order No. 587-U). With this Order, FERC incorporated by reference into its regulations Version 1.9 of the North American Energy Standards Board Wholesale Gas Quadrant's standards. On October 13, 2010, FERC approved ESNG's compliance filing.

P. ENVIRONMENTAL COMMITMENTS AND CONTINGENCIES

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy 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.

As of December 31, 2010, we had $358,000 in environmental liabilities related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of the future costs associated with those sites. As of December 31, 2010, we had approximately $1.3 million in regulatory and other assets for future recovery of environmental costs from Chesapeake's customers through our approved rates. As of December 31, 2010, we had approximately $11.6 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 has approval to recover up to $14.0 million of its environmental costs from insurance and from customers through rates. Approximately $7.8 million of FPU's expected environmental costs have been recovered from insurance and customers through rates as of December 31, 2010. We also had approximately $6.2 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 substantially 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 permanently decommission the AS/SVE system and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery. We have requested and are awaiting a No Further Action determination from the MDE.

Through December 31, 2010, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies. We have recovered approximately $2.2 million through insurance proceeds or in rates and have $667,000 to be recovered through future rates.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a Consent Order entered into with the FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. In 2001, the FDEP approved a RAP requiring construction and operation of a Bio-Sparging and 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. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. The Sixteenth Semi-Annual RAP Implementation Status Report was submitted to the FDEP in December 2010. The groundwater sampling results through December 2010 show a continuing reduction in contaminant concentrations and indicate that the recent treatment system modifications and upgrades have had a beneficial impact on the rate of reduction. At present, we predict that remedial action objectives may be met for the area being treated by the BS/SVE treatment system in approximately two to three years. The cost of operating and monitoring the system is approximately $46,000.

The BS/SVE treatment system does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to the FDEP for review. The FDEP provided comments to the soil excavation interim RAP by letter, dated June 24, 2010. A response letter, dated August 3, 2010, was submitted to FDEP. A subsequent conditional approval letter, dated August 27, 2010, was issued by FDEP. The cost to implement this excavation plan has been estimated at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. Because the costs associated with shoreline stabilization and dewatering (including treatment and discharge of the pumped water) are likely substantial, alternatives to this excavation plan will to be evaluated. We plan to perform the excavation in late 2011 or early 2012.

The 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 the 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.

Through December 31, 2010, we have incurred and paid approximately $1.6 million for this site and estimate an additional cost of $358,000 in the future, which has been accrued. We have recovered through rates $1.3 million of the costs and continue to expect that the remaining $658,000, 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, Suburban Propane. In September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is seeking to meet with FPU and the current site owner, Suburban Propane, to discuss additional field work which the FDEP believes is warranted for the site. Potential costs for investigation and remediation are projected to be $153,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP was also owned by Gulf Power. Portions of the site are now owned by the city of Pensacola and the Florida Department of Transportation ("FDOT"). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action ("NFA") determination for the site, which must include a requirement for institutional and engineering controls. On November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for the property currently owned by FDOT. At this point, it is anticipated that no further monitoring will be required on the site. The remaining consulting and remediation costs are projected to be $7,000.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, a former MGP site which was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In late September 2006, 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, 2010, FPU has paid $650,000 to the Sanford Group escrow account for its share of funding requirements.

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

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

As of December 31, 2010, FPU's remaining share of remediation expenses, including attorneys' fees and costs, is estimated to be $20,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding $13 million to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement.

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

FPU performed additional field work in August 2010, which included the installation of additional groundwater monitoring wells and performance of a comprehensive groundwater sampling event. FPU also performed vapor intrusion sampling in October 2010. The results of the field work were submitted to the FDEP for their review and comment in October 2010. On November 4, 2010, the FDEP issued its comments on the feasibility study and the proposed remedy. On November 16, 2010, FPU presented to the FDEP a new proposed strategy for the site remedy with an aggressive remedial action plan, and the FDEP agreed with the proposal to implement a phased approach. On December 22, 2010, FPU submitted to the FDEP an interim RAP to remediate the east parcel of the site, which the FDEP conditionally approved on February 4, 2011.

FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP's conditions for approval. We estimate that the updated costs of remediation will range from approximately $5.1 million to $13.3 million. This estimate does not include any costs associated with relocation of operations, which is necessary to implement the remedial plan, and any potential costs associated with re-development of the properties.

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

Q. OTHER COMMITMENTS AND CONTINGENCIES

Litigation

In May 2010, a FPU propane customer filed a class action complaint against FPU in Palm Beach County, Florida, alleging, among other things, that FPU acted in a deceptive and unfair manner related to a particular charge by FPU on its bills to propane customers and the description of such charge. The suit sought to certify a class comprised of FPU propane customers to whom such charge was assessed since May 2006 and requested damages and statutory remedies based on the amounts paid by FPU customers for such charge. FPU vigorously denies any wrongdoing and maintains that the particular charge at issue is customary, proper and fair. Without any admission by FPU of any wrongdoing, validity of the claims or a properly certifiable class for the complaint, FPU entered into a settlement agreement with the plaintiff in September 2010 to avoid the burden and expenses of continued litigation. The court approved the final settlement. The judgment becomes final when the time for appeal expires, which is expected on March 13, 2011. To date, there has been no notice of appeal. We recorded $1.2 million of the total estimated costs related to this litigation in 2010, which includes the proposed settlement payment, attorneys' fees and expenses and costs of notice and class administration. As discussed in Note B, "Acquisitions," $835,000 of this contingent liability was determined to be associated with FPU's operations prior to the merger with Chesapeake and was recorded as part of the purchase price allocation. The remaining $370,000 of the total estimated costs, which is related to FPU's operations after the merger with Chesapeake, or the amount incurred after the end of the measurement period for the acquisition accounting, was expensed in 2010.

On March 2, 2011, the City of Marianna, Florida filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the city to provide electric service to customers within and without the city by failing (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the city and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU's customers located within and without the corporate limits of the city. The city is seeking a declaratory judgment to exercise its option under the franchise agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. FPU intends to file a response to the City's complaint and vigorously contest this litigation and intends to oppose the passage of any proposed referendum that is presented to voters to approve the purchase of the FPU property in the City of Marianna.

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

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations 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 2011.

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA requires FPU to comply with the following ratios based on the result of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times and (b) fixed charge coverage ratio greater than 1.5. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU's agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operation interest coverage ratio (minimum of 2 times) and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of action taken or proposed to be taken to be compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. FPU was in compliance with these requirements as of December 31, 2010.

Corporate Guarantees

The Board of Directors has authorized the Company to issue up to $35 million of corporate guarantees on behalf of our subsidiaries and for letters of credit. As of March 2, 2011, the Board increased this limit from $35 million to $45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2010 was $25.6 million, with the guarantees expiring on various dates in 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $440,625 which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various outstanding insurance policies. As a result of the recent change in our primary insurance company, we have issued an additional letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of December 31, 2010. We do not anticipate that the letters of credit will be drawn upon by the counterparties and we expect that the letters of credit will be renewed to the extent necessary in the future. We provided a letter of credit for $2.0 million to TETLP related to the Precedent Agreement with TETLP, which is further described below.

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP's mainline system by up to 190,000 dekatherms per day ("Dts/d"). The Precedent Agreement provides that, upon satisfaction of certain conditions, the parties will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 30,000 and 10,000 Dts/d, respectively, to be effective on the service commencement date of the project, which is currently projected to occur in November 2012. Each firm transportation service contract shall, among other things, provide for: (a) the maximum daily quantity of Dts/d described above; (b) a term of 15 years; (c) a receipt point at Clarington, Ohio; (d) a delivery point at Honey Brook, Pennsylvania; and (f) certain credit standards and requirements for security. Commencement of service and TETLP's and our rights and obligations under the two firm transportation service contracts are subject to satisfaction of various conditions specified in the Precedent Agreement.

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

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

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP's pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP's pre-service costs could be approximately $4.7 million as of December 31, 2010. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2011, our proportionate share could be as much as approximately $45 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP's pre-service costs is remote.

As of December 31, 2010, we provided a letter of credit for $2.0 million under the Precedent Agreement with TETLP as required. This letter of credit is expected to increase quarterly as TETLP's pre-service costs increase and will not exceed more than the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

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

TETLP is proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project, including, but not limited to, approval by the FERC. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or ESNG.

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

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing a sales tax audit in Florida. During 2010, we recorded an accrual of $698,000 related to additional sales taxes and gross receipts taxes owed to various states.

Other Contingency

In 2010, we recorded a $750,000 accrual to the regulatory risk for FPU's natural gas distribution operation associated with its earnings, merger benefits and recovery of its purchase premium (See Note O, "Rates and Other Regulatory Activities," to the Consolidated Financial Statements for further discussion).

R. QUARTERLY FINANCIAL DATA (UNAUDITED)

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

For the Quarters Ended	**March 31**	**June 30**	**September 30**	**December 31**
(in thousands except per share amounts)				
2010				
Operating Revenue	**$153,260**	**$80,061**	**$76,466**	**$117,759**
Operating Income	**$25,398**	**$7,761**	**$4,583**	**$14,188**
Net Income	**$13,974**	**$3,340**	**$1,628**	**$7,113**
Earnings per share:				
Basic	**$1.48**	**$0.35**	**$0.17**	**$0.75**
Diluted	**$1.47**	**$0.35**	**$0.17**	**$0.74**
2009[1]				
Operating Revenue	$104,479	$40,834	$31,758	$91,715
Operating Income	$15,966	$2,856	$2,257	$12,658
Net Income	$8,593	$806	$308	$6,191
Earnings per share:				
Basic	$1.26	$0.12	$0.04	$0.71
Diluted	$1.24	$0.12	$0.04	$0.71

(1) The quarterly results prior to the completion of the merger with FPU exclude the results from FPU. The merger 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, 2010. 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, 2010.

Changes in Internal Controls

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2010, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

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

CEO and CFO Certifications

The Company's Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010. In addition, on June 3, 2010 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 on the following page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

We have audited Chesapeake Utilities Corporation's (the "Company") internal control over financial reporting as of December 31, 2010, 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 accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Chesapeake Utilities Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the related consolidated statements of income, stockholders' equity and cash flows of Chesapeake Utilities Corporation, and our report dated March 8, 2011 expressed an unqualified opinion.

/s/ ParenteBeard LLC
ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2011

ITEM 9B. OTHER INFORMATION.

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANACE.

The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned "Election of Directors (Proposal 1)," "Information Concerning Nominees and Continuing Directors," "Corporate Governance," "Committees of the Board – Audit Committee" and "Section 16(a) Beneficial Ownership Reporting Compliance," to be filed no later than March 31, 2011, in connection with the Company's Annual Meeting to be held on or about May 4, 2011.

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

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

ITEM 11. EXECUTIVE COMPENSATION.

The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned "Director Compensation," "Executive Compensation" and "Compensation Discussion and Analysis" in the Proxy Statement to be filed no later than March 31, 2011, in connection with the Company's Annual Meeting to be held on or about May 4, 2011.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned "Security Ownership of Certain Beneficial Owners and Management" to be filed no later than March 31, 2011, in connection with the Company's Annual Meeting to be held on or about May 4, 2011.

The following table sets forth information, as of December 31, 2010, 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	-	-	402,843 [1]
Equity compensation plans not approved by security holders	-	-	-
Total	-	-	402,843

[1] Includes 345,028 shares under the 2005 Performance Incentive Plan, 34,215 shares available under the 2005 Directors Stock Compensation Plan, and 23,600 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, 2011 in connection with the Company's Annual Meeting to be held on or about May 4, 2011.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned "Fees and Services of Independent Registered Public Accounting Firm," to be filed no later than March 31, 2011, in connection with the Company's Annual Meeting to be held on or about May 4, 2011.

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, 2010, 2009, and 2008;
- Consolidated Balance Sheets at December 31, 2010 and December 31, 2009;
- Consolidated Statements of Cash Flows for each of the three years ended December 31, 2010, 2009, and 2008;
- Consolidated Statements of Stockholders' Equity for each of the three years ended December 31, 2010, 2009, and 2008; 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, 2006 relating to the sale and issuance of 600,300 shares of Chesapeake's common stock, is incorporated herein by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed November 16, 2006, File No. 001-11590.
- Exhibit 2.1 — Agreement and Plan of Merger between Chesapeake Utilities Corporation and Florida Public Utilities Company dated April 17, 2009, is incorporated herein by reference to Exhibit 2.1 of our Current Report on Form 8-K, filed April 20, 2009, File No. 001-11590.
- Exhibit 3.1 — Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
- Exhibit 3.2 — Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective April 7, 2010, are incorporated herein by reference to Exhibit 3 of the Company's Current Report on Form 8-K, filed April 13, 2010, File No. 001-11590.
- Exhibit 4.1 — Form of Indenture between Chesapeake and Boatmen's Trust Company, Trustee, with respect to the 8 1/4% Convertible Debentures is incorporated herein by reference to Exhibit 4.2 of our Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.
- Exhibit 4.2 — Note Purchase Agreement, entered into by the Company on October 2, 1995, pursuant to which Chesapeake privately placed $10 million of its 6.91% Senior Notes, paid off in

2010, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.

- Exhibit 4.3 — Note Purchase Agreement, entered into by Chesapeake on December 15, 1997, pursuant to which Chesapeake privately placed $10 million of its 6.85% Senior Notes due in 2012, is incorporated by reference to Exhibit 4.3 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
- Exhibit 4.4 — Note Purchase Agreement entered into by Chesapeake on December 27, 2000, pursuant to which Chesapeake privately placed $20 million of its 7.83% Senior Notes, due in 2015, is incorporated by reference to Exhibit 4.4 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
- Exhibit 4.5 — Note Agreement entered into by Chesapeake on October 31, 2002, pursuant to which Chesapeake privately placed $30 million of its 6.64% Senior Notes, due in 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.
- Exhibit 4.6 — Note Agreement entered into by Chesapeake on October 18, 2005, pursuant to which Chesapeake, on October 12, 2006, privately placed $20 million of its 5.5% Senior Notes, due in 2020, with Prudential Investment Management, Inc., is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
- Exhibit 4.7 — Note Agreement entered into by Chesapeake on October 31, 2008, pursuant to which Chesapeake, on October 31, 2008, privately placed $30 million of its 5.93% Senior Notes, due in 2023, with General American Life Insurance Company and New England Life Insurance Company, is incorporated by reference to Exhibit 4.7 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
- Exhibit 4.8 — Form of Indenture of Mortgage and Deed of Trust between Florida Public Utilities Company and the trustee, dated September 1, 1942 for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.
- Exhibit 4.9 — Sixteenth Supplemental Indenture entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on December 1, 2009, pursuant to which Chesapeake Utilities Corporation, on December 1, 2009 guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is filed herewith.
- Exhibit 4.10 — Fifteenth Supplemental Indenture entered into by Florida Public Utilities Company on November 1, 2001, pursuant to which Florida Public Utilities Company, on November 1, 2001, privately placed $14,000,000 of its 4.90% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(c) of Florida Public Utilities Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.
- Exhibit 4.11 — 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 4.12 — Thirteenth Supplemental Indenture entered into by Florida Public Utilities Company on June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
- Exhibit 4.13 — 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 10.1* Chesapeake Utilities Corporation Cash Bonus Incentive Plan, dated January 1, 2005, is incorporated herein by reference to Exhibit 10.3 of our Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-11590.
- Exhibit 10.2* Chesapeake Utilities Corporation Directors Stock Compensation Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
- Exhibit 10.3* Chesapeake Utilities Corporation Employee Stock Award Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
- Exhibit 10.4* Chesapeake Utilities Corporation Performance Incentive Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
- Exhibit 10.5* Chesapeake Utilities Corporation Deferred Compensation Plan, amended and restated as of January 1, 2009, is incorporated herein by reference to Exhibit 10.5 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
- Exhibit 10.6 First Amendment to the Chesapeake Utilities Corporation Deferred Compensation Plan, dated December 28, 2010, is filed herewith.
- Exhibit 10.7* 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 our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
- Exhibit 10.8 Consulting Agreement dated January 3, 2011, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is filed herewith.
- Exhibit 10.9* Executive Employment Agreement dated January 14, 2011, by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
- Exhibit 10.10* 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 our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
- Exhibit 10.11* Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
- Exhibit 10.12* 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 our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
- Exhibit 10.13* Executive Employment Agreement dated March 3, 2011, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is filed herewith.
- Exhibit 10.14* 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 10.15* 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 10.16* 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 10.17* 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 10.18* 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 10.19* 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 10.20* 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 10.21* 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 10.22* 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 10.23* 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 10.24* Form of Performance Share Agreement effective January 7, 2009 for the period 2009 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of 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 10.25* Form of Performance Share Agreement effective January 6, 2010 for the period 2010 to 2012, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of John R. Schimkaitis, Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, and Joseph Cummiskey is incorporated herein by reference to Exhibit 10.24 on Form 10-K for the year ended December 31, 2009, File No. 001-11590

- Exhibit 10.26* Performance Share Agreement dated January 20, 2010 for the period 2010 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Joseph Cummiskey is incorporated herein by reference to Exhibit 10.24 on Form 10-K for the year ended December 31, 2009, File No. 001-11590.

- Exhibit 10.27* Form of Performance Share Agreement effective January 14, 2011 for the period 2011 to 2013, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Joseph Cummiskey, and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.

- Exhibit 10.28* Form of Performance Share Agreement effective January 14, 2011 for the period 2011 to 2012, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters and Elaine B. Bittner, is filed herewith.

- Exhibit 10.29* Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.

- Exhibit 10.30* First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is filed herewith.

- Exhibit 10.31* Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.28 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.

- Exhibit 10.32* First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, dated October 28, 2010, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2010, File No. 001-11590.

- Exhibit 10.33 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 10.34 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 10.35 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 10.36 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 10.37 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 10.38 Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2022 (Contract No. 107035), is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
- Exhibit 10.39 Term Note Agreement entered into by Chesapeake Utilities Corporation on March 16, 2010, pursuant to the $29 million credit facility with PNC Bank, N.A., is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
- Exhibit 10.40 Precedent Agreement between Chesapeake Utilities Corporation and Texas Eastern Transmission LP, dated April 8, 2010 is incorporated herein by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
- Exhibit 10.41 Form of Franchise Agreement between Florida Public Utilities Company and the city of Marianna, effective February 1, 2010, is filed herewith.
- Exhibit 10.42 Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, dated December 28, 2006, effective January 1, 2008 is hereby incorporated by reference as Exhibit 10(s) on Florida Public Utilities Company's Annual Report on Form 10-K for the year ended December 31, 2006, file No. 001-10608.
- Exhibit 10.43 Amendment to Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, effective January 25, 2011, is filed herewith.
- Exhibit 12 Computation of Ratio of Earning to Fixed Charges is filed herewith.
- Exhibit 14.1 Code of Ethics for Financial Officers is filed herewith.
- 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, 2011, 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, 2011, 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, 2011, 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, 2011, is filed herewith.

* Management contract or compensatory plan or agreement.

SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

By: /S/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President and Chief Executive Officer
Date: March 8, 2011

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

/S/ RALPH J. ADKINS
Ralph J. Adkins,
Chairman of the Board and Director
Date: March 2, 2011

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director
Date: March 8, 2011

/S/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
Date: March 8, 2011

/S/ EUGENE H. BAYARD,ESQ
Eugene H. Bayard, Director
Date: March 2, 2011

/S/ RICHARD BERNSTEIN
Richard Bernstein, Director
Date: March 2, 2011

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
Date: March 7, 2011

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
Date: March 2, 2011

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
Date: March 2, 2011

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
Date: March 2, 2011

/S/ J. PETER MARTIN
J. Peter Martin, Director
Date: March 2, 2011

/S/ JOSEPH E. MOORE, ESQ
Joseph E. Moore, Esq., Director
Date: March 2, 2011

/S/ CALVERT A. MORGAN, JR
Calvert A. Morgan, Jr., Director
Date: March 2, 2011

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
Date: March 2, 2011

/S/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Vice Chairman of the Board and Director
Date: March 2, 2011

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, 2011 relating to the consolidated financial statements of Chesapeake Utilities Corporation as of December 31, 2010 and 2009 and for each of the years in the three-year period ended December 31, 2010, 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, 2011

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

Assets	**December 31, 2010**	**December 31, 2009**
(in thousands)		
Total property, plant and equipment	**$202,807**	$191,440
Less: Accumulated depreciation and amortization	**(49,223)**	(46,297)
Plus: Construction work in progress	**1,492**	1,338
Net property, plant and equipment	**155,076**	146,481
Investments, at fair value	**2,368**	1,959
Investments in subsidiaries	**179,580**	160,150
Current Assets		
Cash and cash equivalents	**4,229**	973
Accounts receivable (less allowance for uncollectible accounts of $432 and $458, respectively)	**11,623**	9,356
Accrued revenue	**6,458**	4,936
Accounts receivable from affiliates	**74,663**	56,587
Propane inventory, at average cost	**635**	624
Other inventory, at average cost	**970**	971
Regulatory assets	**51**	1,205
Storage gas prepayments	**5,084**	6,144
Income taxes receivable	**4,003**	822
Deferred income taxes	**369**	1,909
Prepaid expenses	**2,310**	3,047
Other current assets	**176**	79
Total current assets	**110,571**	86,653
Deferred Charges and Other Assets		
Long-term receivables	**133**	331
Regulatory assets	**2,820**	3,610
Other deferred charges	**603**	479
Total deferred charges and other assets	**3,556**	4,420
Total Assets	**$451,151**	$399,663

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

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

Capitalization and Liabilities	**December 31, 2010**	**December 31, 2009**
(in thousands)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 and 12,000,000 shares, respectively)	**$4,635**	$4,572
Additional paid-in capital	**148,159**	144,502
Retained earnings	**76,805**	63,231
Accumulated other comprehensive loss	**(3,134)**	(2,865)
Deferred compensation obligation	**777**	739
Treasury stock	**(777)**	(739)
Total stockholders' equity	**226,465**	209,440
Long-term debt, net of current maturities	**71,682**	79,611
Total capitalization	**298,147**	289,051
Current Liabilities		
Current portion of long-term debt	**7,727**	6,636
Short-term borrowing	**63,958**	30,023
Accounts payable	**10,401**	9,157
Customer deposits and refunds	**7,619**	4,410
Accrued interest	**1,015**	1,003
Dividends payable	**3,143**	2,959
Accrued compensation	**3,377**	2,450
Regulatory liabilities	**2,432**	5,934
Other accrued liabilities	**2,635**	1,647
Total current liabilities	**102,307**	64,219
Deferred Credits and Other Liabilities		
Deferred income taxes	**20,999**	16,494
Deferred investment tax credits	**122**	157
Regulatory liabilities	**709**	695
Environmental liabilities	**358**	531
Other pension and benefit costs	**5,045**	5,674
Accrued asset removal cost - Regulatory liability	**18,805**	18,248
Other liabilities	**4,659**	4,594
Total deferred credits and other liabilities	**50,697**	46,393
Other commitments and contingencies		
Total Capitalization and Liabilities	**$451,151**	$399,663

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

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,		2010		2009		2008
(in thousands)						
Operating Revenues	$	95,764	$	101,577	$	103,733
Operating Expenses						
Cost of sales		52,295		62,339		65,446
Operations		19,919		18,487		16,039
Transaction-related costs		660		1,478		1,153
Maintenance		1,165		1,535		1,303
Depreciation and amortization		4,365		4,194		3,918
Other taxes		3,788		3,564		3,380
Total operating expenses		82,192		91,597		91,239
Operating Income		13,572		9,980		12,494
Income from equity investments		19,430		12,042		7,781
Other loss, net of other expenses		(30)		(30)		(106)
Interest charges		2,837		3,066		3,026
Income Before Income Taxes		30,135		18,926		17,143
Income taxes		4,079		3,029		3,536
Net Income	$	26,056	$	15,897	$	13,607

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

Chesapeake Utilities Corporation and subsidiaries
Schedule I
Parent Company Condensed financial statements
Chesapeake Utilities Corporation (Parent)
Condensed Statement of Cash Flows

For the Years Ended December 31,	2010	2009	2008
(in thousands)			
Operating Activities			
Net Income	**$26,056**	$15,897	$13,607
Adjustments to reconcile net income to net operating cash:			
Equity earnings in subsidiaries	**(19,382)**	(12,042)	(7,781)
Depreciation and amortization	**4,366**	4,190	3,918
Depreciation and accretion included in other costs	**1,878**	1,773	1,389
Deferred income taxes, net	**6,901**	2,821	5,147
Unrealized (gain) loss on investments	**(113)**	(212)	509
Employee benefits and compensation	**(169)**	1,217	152
Share based compensation	**1,155**	1,306	820
Other, net	**(46)**	8	11
Changes in assets and liabilities:			
Purchase of investments	**(297)**	(146)	(201)
Accounts receivable and accrued revenue	**(3,814)**	(16,770)	(3,016)
Propane inventory, storage gas and other inventory	**1,050**	3,383	(3,854)
Regulatory assets	**1,716**	(1,825)	606
Prepaid expenses and other current assets	**653**	(1,050)	(516)
Other deferred charges	**(180)**	(72)	(8)
Long-term receivables	**198**	181	199
Accounts payable and other accrued liabilities	**1,636**	9,832	3,323
Income taxes receivable	**(3,858)**	2,791	(3,113)
Accrued interest	**12**	(20)	158
Customer deposits and refunds	**3,208**	(1,147)	34
Accrued compensation	**823**	352	377
Regulatory liabilities	**(3,488)**	3,603	(2,379)
Other liabilities	**64**	886	(23)
Net cash provided by operating activities	**18,369**	14,956	9,359
Investing Activities			
Property, plant and equipment expenditures	**(13,969)**	(12,615)	(16,328)
Proceeds from investments	-	1,000	500
Cash acquired in the merger, net of cash paid	-	(16)	-
Environmental expenditures	**54**	(86)	(480)
Net cash used in investing activities	**(13,915)**	(11,717)	(16,308)
Financing Activities			
Change in receivable/payable with affiliates	**(18,051)**	13,379	4,302
Common stock dividends	**(11,013)**	(7,957)	(7,810)
Issuance of stock for Dividend Reinvestment Plan	**568**	392	(118)
Change in cash overdrafts due to outstanding checks	**3,256**	835	(684)
Net borrowing (repayment) under line of credit agreements	**1,579**	(3,812)	(11,980)
Other short-term borrowing	**29,100**	-	-
Proceeds from issuance of long-term debt	-	-	29,961
Repayment of long-term debt	**(6,637)**	(6,637)	(7,637)
Net cash provided by (used in) financing activities	**(1,198)**	(3,800)	6,034
Net Increase (Decrease) in Cash and Cash Equivalents	**3,256**	(561)	(915)
Cash and Cash Equivalents — Beginning of Period	**973**	1,534	2,449
Cash and Cash Equivalents — End of Period	**$4,229**	$973	$1,534

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

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 P, Environmental Commitments and Contingencies and Note Q, Other Commitments and Contingencies."

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

Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

		Additions			
For the Year Ended December 31,	Balance at Beginning of Year	Charged to Income	Other Accounts [1]	Deductions [2]	Balance at End of Year
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
(In thousands)					
2010	**$1,609**	**$1,129**	**$181**	**($1,725)**	**$1,194**
2009	$1,159	$1,138	$616	($1,304)	$1,609
2008	$952	$1,186	$241	($1,220)	$1,159

(1) Recoveries.

(2) Uncollectible accounts charged off.

EXHIBIT 12

Chesapeake Utilities Corporation
Ratio of Earnings to Fixed Charges

For the Years Ended December 31,	2010	2009 (a)	2008	2007	2006
(in thousands, except ratio of earnings to fixed charges)					
Income from continuing operations	**$26,056**	$15,897	$13,607	$13,218	$10,748
Add:					
Income taxes	**16,923**	10,918	8,817	8,597	6,999
Portion of rents representative of interest factor	**356**	333	294	245	227
Interest on indebtedness	**9,090**	7,042	6,110	6,539	5,722
Amortization of debt discount and expense	**56**	43	47	51	52
Earnings as adjusted	**$52,481**	$34,233	$28,875	$28,650	$23,748
Fixed Charges					
Portion of rents representative of interest factor	**$356**	$333	$294	$245	$227
Interest on indebtedness	**9,090**	7,042	6,110	6,539	5,722
Amortization of debt discount and expense	**56**	43	47	51	52
Fixed Charges	**$9,502**	$7,418	$6,451	$6,835	$6,001
Ratio of Earnings to Fixed Charges	**5.52**	4.61	4.48	4.19	3.96

(a) Includes the results from the merger with Florida Public Utilities Company, which became effective on October 28, 2009.

EXHIBIT 21

Chesapeake Utilities Corporation
Subsidiaries of the Registrant

Subsidiaries	State Incorporated
Eastern Shore Natural Gas Company	Delaware
Sharp Energy, Inc.	Delaware
Chesapeake Service Company	Delaware
Xeron, Inc.	Mississippi
Chesapeake OnSight Services, LLC	Delaware
Peninsula Energy Services Company, Inc.	Delaware
Peninsula Pipeline Company, Inc.	Delaware
Florida Public Utilities Company	Florida

Subsidiaries of Sharp Energy, Inc.	State Incorporated
Sharpgas, Inc.	Delaware

Subsidiaries of Florida Public Utilities Company	State Incorporated
Flo-Gas Corporation	Florida

Subsidiaries of Chesapeake Service Company	State Incorporated
Skipjack, Inc.	Delaware
BravePoint, Inc.	Georgia
Chesapeake Investment Company	Delaware
Eastern Shore Real Estate, Inc.	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Chesapeake Utilities Corporation

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-156192, 333-63381 and 333-121524) and Form S-8 (Nos. 333-01175, 333-94159, 333-124646, 333-124694 and 333-124717) of Chesapeake Utilities Corporation of our reports dated March 8, 2011, relating to the consolidated financial statements, financial statement schedules, and the effectiveness of Chesapeake Utilities Corporation's internal control over financial reporting, which appear in this Form 10-K.

/s/ ParenteBeard LLC
ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2011

EXHIBIT 31.1

CERTIFICATE PURSUANT TO RULE 13A-14(A) AND 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Michael P. McMasters, certify that:

1. I have reviewed this annual report on Form 10-K of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2011

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATE PURSUANT TO RULE 13A-14(A) AND 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Beth W. Cooper, certify that:

1. I have reviewed this annual report on Form 10-K of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2011

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATE OF CHIEF EXECUTIVE OFFICER
OF CHESAPEAKE UTLITIES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

I, Michael, P. McMasters, President and Chief Executive Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Annual Report on Form 10-K of Chesapeake Utilities Corporation ("Chesapeake") for the year ended December 31, 2010, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters
March 8, 2011

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

**CERTIFICATE OF CHIEF FINANCIAL OFFICER
OF CHESAPEAKE UTLITIES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

I, Beth W. Cooper, Senior Vice President and Chief Financial Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Annual Report on Form 10-K of Chesapeake Utilities Corporation ("Chesapeake") for the year ended December 31, 2010, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ BETH W. COOPER
Beth W. Cooper
March 8, 2011

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Upon written request,
Chesapeake will provide, free of
charge, a copy of any exhibit to
the 2010 Annual Report on
Form 10-K not included
in this document.

Exhibit A(2)

QUARTERLY REPORT
FORM 10-Q

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

FORM 10-Q

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

For the quarterly period ended: June 30, 2011

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______ to ______

Commission File Number: 001-11590

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

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

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)

(302) 734-6799
(Registrant's telephone number, including area code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ] Smaller reporting company [ ]

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

Common Stock, par value $0.4867 — 9,564,197 shares outstanding as of July 31, 2011.

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. is 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
Eastern Shore	Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake
FPU	Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake, effective October 28, 2009
PESCO	Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake
Peninsula Pipeline	Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake
Sharp	Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake's and Sharp's subsidiary, Sharpgas, Inc.
Xeron	Xeron, Inc., a wholly-owned subsidiary of Chesapeake

Regulatory Agencies

Delaware PSC	Delaware Public Service Commission
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
Florida PSC	Florida Public Service Commission
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Accounting Standards Related

FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
ECCR	Energy Conservation Cost Recovery
FGT	Florida Gas Transmission Company
FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf Power	Gulf Power Corporation
Gulfstream	Gulfstream Natural Gas System, LLC
HDD	Heating Degree-Days
MWH	Megawatt Hour
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OTC	Over-the-Counter
PIP	Performance Incentive Plan
RAP	Remedial Action Plan
Sanford Group	FPU and Other Responsible Parties involved with the Sanford Environmental Site
TETLP	Texas Eastern Transmission, LP
TOU	Time-of-Use

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

For the Three Months Ended June 30,	2011	2010
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated Energy	$54,327	$52,740
Unregulated Energy	29,692	24,615
Other	2,812	2,706
Total operating revenues	86,831	80,061
Operating Expenses		
Regulated energy cost of sales	24,882	24,625
Unregulated energy and other cost of sales	24,420	20,384
Operations	20,401	18,526
Maintenance	1,892	1,789
Depreciation and amortization	4,937	4,545
Other taxes	2,523	2,431
Total operating expenses	79,055	72,300
Operating Income	7,776	7,761
Other income (loss), net of expenses	27	(11)
Interest charges	2,114	2,305
Income Before Income Taxes	5,689	5,445
Income tax expense	2,169	2,105
Net Income	$3,520	$3,340
Weighted-Average Common Shares Outstanding:		
Basic	9,557,707	9,467,222
Diluted	9,650,887	9,557,352
Earnings Per Share of Common Stock:		
Basic	$0.37	$0.35
Diluted	$0.37	$0.35
Cash Dividends Declared Per Share of Common Stock	$0.345	$0.330

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

For the Six Months Ended June 30,	2011	2010
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated Energy	**$139,329**	$144,367
Unregulated Energy	**88,442**	83,885
Other	**5,658**	5,069
Total operating revenues	**233,429**	233,321
Operating Expenses		
Regulated energy cost of sales	**72,872**	78,889
Unregulated energy and other cost of sales	**68,711**	65,474
Operations	**40,237**	37,524
Maintenance	**3,595**	3,489
Depreciation and amortization	**9,958**	9,389
Other taxes	**5,441**	5,397
Total operating expenses	**200,814**	200,162
Operating Income	**32,615**	33,159
Other income, net of expenses	**50**	103
Interest charges	**4,265**	4,667
Income Before Income Taxes	**28,400**	28,595
Income tax expense	**11,133**	11,281
Net Income	**$17,267**	$17,314
Weighted-Average Common Shares Outstanding:		
Basic	**9,546,606**	9,443,708
Diluted	**9,642,374**	9,550,670
Earnings Per Share of Common Stock:		
Basic	**$1.81**	$1.83
Diluted	**$1.79**	$1.82
Cash Dividends Declared Per Share of Common Stock	**$0.675**	$0.645

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

For the Six Months Ended June 30,	2011	2010
(in thousands)		
Operating Activities		
Net Income	**$17,267**	$17,314
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**9,958**	9,389
Depreciation and accretion included in other costs	**2,473**	2,199
Deferred income taxes, net	**12,449**	3,683
Loss on sale of assets	**94**	71
Unrealized (gain) loss on commodity contracts	**30**	(374)
Unrealized (gain) loss on investments	**(131)**	60
Employee benefits	**309**	(383)
Share-based compensation	**705**	612
Other, net	**(18)**	(105)
Changes in assets and liabilities:		
Sale (purchase) of investments	**258**	(131)
Accounts receivable and accrued revenue	**14,017**	26,485
Propane inventory, storage gas and other inventory	**3,315**	3,382
Regulatory assets	**601**	1,226
Prepaid expenses and other current assets	**1,792**	3,539
Accounts payable and other accrued liabilities	**674**	(14,796)
Income taxes receivable	**(2,666)**	2,201
Accrued interest	**(241)**	(259)
Customer deposits and refunds	**(1,182)**	1,041
Accrued compensation	**(2,234)**	83
Regulatory liabilities	**2,887**	1,194
Other liabilities	**(268)**	583
Net cash provided by operating activities	**60,089**	57,014
Investing Activities		
Property, plant and equipment expenditures	**(21,236)**	(13,600)
Proceeds from sales of assets	**344**	34
Purchase of investments	**(200)**	(310)
Environmental expenditures	**(326)**	(410)
Net cash used in investing activities	**(21,418)**	(14,286)
Financing Activities		
Common stock dividends	**(5,685)**	(5,369)
(Purchase) issuance of stock for Dividend Reinvestment Plan	**(609)**	268
Change in cash overdrafts due to outstanding checks	**(3,193)**	(834)
Net repayment under line of credit agreements	**(27,417)**	(29,188)
Other short-term borrowing	**(29,100)**	29,100
Proceeds from issuance of long-term debt	**29,000**	-
Repayment of long-term debt	**(1,482)**	(30,277)
Net cash used in financing activities	**(38,486)**	(36,300)
Net Increase in Cash and Cash Equivalents	**185**	6,428
Cash and Cash Equivalents — Beginning of Period	**1,643**	2,828
Cash and Cash Equivalents — End of Period	**$1,828**	$9,256

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Assets	**June 30, 2011**	**December 31, 2010**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	**$511,008**	$500,689
Unregulated energy	**62,399**	61,313
Other	**18,926**	16,989
Total property, plant and equipment	**592,333**	578,991
Less: Accumulated depreciation and amortization	**(129,054)**	(121,628)
Plus: Construction work in progress	**8,317**	5,394
Net property, plant and equipment	**471,596**	462,757
Investments, at fair value	4,109	4,036
Current Assets		
Cash and cash equivalents	**1,828**	1,643
Accounts receivable (less allowance for uncollectible accounts of $1,095 and $1,194, respectively)	**80,381**	88,074
Accrued revenue	**8,655**	14,978
Propane inventory, at average cost	**6,790**	8,876
Other inventory, at average cost	**3,266**	3,084
Regulatory assets	**289**	51
Storage gas prepayments	**3,672**	5,084
Income taxes receivable	**9,414**	6,748
Deferred income taxes	**2,170**	2,191
Prepaid expenses	**3,111**	4,613
Mark-to-market energy assets	**335**	1,642
Other current assets	**226**	245
Total current assets	**120,137**	137,229
Deferred Charges and Other Assets		
Goodwill	**35,613**	35,613
Other intangible assets, net	**3,293**	3,459
Long-term receivables	**26**	155
Regulatory assets	**22,300**	23,884
Other deferred charges	**3,415**	3,860
Total deferred charges and other assets	**64,647**	66,971
Total Assets	**$660,489**	$670,993

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	June 30, 2011	December 31, 2010
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share		
(authorized 25,000,000 shares)	**$4,654**	$4,635
Additional paid-in capital	**148,796**	148,159
Retained earnings	**87,549**	76,805
Accumulated other comprehensive loss	**(2,999)**	(3,360)
Deferred compensation obligation	**796**	777
Treasury stock	**(796)**	(777)
Total stockholders' equity	**238,000**	226,239
Long-term debt, net of current maturities	**117,123**	89,642
Total capitalization	**355,123**	315,881
Current Liabilities		
Current portion of long-term debt	**9,196**	9,216
Short-term borrowing	**4,248**	63,958
Accounts payable	**64,427**	65,541
Customer deposits and refunds	**25,135**	26,317
Accrued interest	**1,548**	1,789
Dividends payable	**3,299**	3,143
Accrued compensation	**4,623**	6,784
Regulatory liabilities	**11,960**	9,009
Mark-to-market energy liabilities	**216**	1,492
Other accrued liabilities	**12,081**	10,393
Total current liabilities	**136,733**	197,642
Deferred Credits and Other Liabilities		
Deferred income taxes	**92,700**	80,031
Deferred investment tax credits	**203**	243
Regulatory liabilities	**3,670**	3,734
Environmental liabilities	**9,414**	10,587
Other pension and benefit costs	**17,816**	18,199
Accrued asset removal cost - Regulatory liability	**35,919**	35,092
Other liabilities	**8,911**	9,584
Total deferred credits and other liabilities	**168,633**	157,470
Other commitments and contingencies (Note 4 and 5)		
Total Capitalization and Liabilities	**$660,489**	$670,993

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

	Common Stock							
(in thousands, except shares and per share data)	Number of Shares[(6)]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2009	9,394,314	$4,572	$144,502	$63,231	($2,524)	$739	($739)	$209,781
Net Income				26,056				26,056
Other comprehensive income, net of tax								
Employee Benefit Plans, net of tax								
Amortization of prior service costs [(4)]					8			8
Net Loss [(5)]					(844)			(844)
Total comprehensive income								25,220
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Tax benefit on share based compensation			253					253
Share based compensation [(1)(3)]	36,415	17	620					637
Deferred Compensation Plan						38	(38)	-
Purchase of treasury stock	(1,144)						(38)	(38)
Sale and distribution of treasury stock	1,144						38	38
Dividends on stock-based compensation				(104)				(104)
Cash dividends [(2)]				(12,378)				(12,378)
Balances at December 31, 2010	9,524,195	4,635	148,159	76,805	(3,360)	777	(777)	226,239
Net Income				17,267				17,267
Other comprehensive income, net of tax								
Employee Benefit Plans, net of tax								
Amortization of prior service costs [(4)]					4			4
Net Gain [(5)]					357			357
Total comprehensive income								17,628
Dividend Reinvestment Plan	-		(11)					(11)
Retirement Savings Plan	2,002	1	79					80
Conversion of debentures	5,691	3	94					97
Share based compensation [(1)(3)]	30,430	15	475					490
Deferred Compensation Plan						19	(19)	-
Purchase of treasury stock	(473)						(19)	(19)
Sale and distribution of treasury stock	473						19	19
Dividends on stock-based compensation				(73)				(73)
Cash dividends [(2)]				(6,450)				(6,450)
Balances at June 30, 2011	9,562,318	$4,654	$148,796	$87,549	($2,999)	$796	($796)	$238,000

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

(2) Cash dividends declared per share for the periods ended June 30, 2011 and December 31, 2010 were $0.675 and $1.305, respectively.

(3) The shares issued under the Performance Incentive Plan ("PIP") are net of shares withheld for employee taxes. For the periods ended June 30, 2011 and December 31, 2010 the Company withheld 12,324 and 17,695 shares, respectively, for taxes.

(4) Tax expense recognized on the prior service cost component of employees benefit plans for the periods ended June 30, 2011 and December 31, 2010 were approximately $3 and $5, respectively.

(5) Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended June 30, 2011 and December 31, 2010, were $239 and ($541), respectively.

(6) Includes 30,078 and 29,596 shares at June 30, 2011 and December 31, 2010, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the "Company," "Chesapeake," "we," "us" and "our" are intended to mean the Registrant and its subsidiaries, or the Registrant's subsidiaries, as appropriate in the context of the disclosure.

The accompanying unaudited condensed consolidated financial statements have been prepared in compliance with the rules and regulations of the Securities and Exchange Commission ("SEC") and United States of America Generally Accepted Accounting Principles ("GAAP"). In accordance with these rules and regulations, certain information and disclosures normally required for audited financial statements have been condensed or omitted. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto, included in our latest Annual Report on Form 10-K filed with the SEC on March 8, 2011. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is highest due to colder temperatures.

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

Reclassifications

We reclassified certain amounts in the condensed consolidated statements of income for the three and six months ended June 30, 2010, and the condensed consolidated statement of cash flows for the six months ended June 30, 2010, to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Recent Accounting Amendments Yet to be Adopted by the Company

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

In June 2011, the FASB issued ASU 2011-05, "Presentation of Comprehensive Income." ASU 2011-05 amends the guidance in Topic 220 "Comprehensive Income," by eliminating the option to present components of other comprehensive income in the statement of stockholders' equity. Instead, the new guidance now requires entities to present all non-owner changes in stockholders' equity either as a single continuous statement of comprehensive income or as two separate but consecutive statements. The components of other comprehensive income ("OCI") have not changed nor has the guidance on when OCI items are reclassified to net income; however, the amendments require entities to present all reclassification adjustments from OCI to net income on the face of the statement of comprehensive income. Similarly, ASU 2011-05 does not change the guidance to disclose OCI components gross or net of the effect of income taxes, provided that the tax effects are presented on the face of the statement in which OCI is presented, or disclosed in the notes to the financial statements. For public entities, the amendments in ASU 2011-05 are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2011. The amendments should be applied retrospectively, and early adoption is permitted. We plan on complying with the new OCI presentation at the end of 2011.

2. Calculation of Earnings Per Share

	Three Months		Six Months	
For the Periods Ended June 30,	**2011**	**2010**	**2011**	**2010**
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$3,520**	$3,340	**$17,267**	$17,314
Weighted average shares outstanding	**9,557,707**	9,467,222	**9,546,606**	9,443,708
Basic Earnings Per Share	**$0.37**	$0.35	**$1.81**	$1.83
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$3,520**	$3,340	**$17,267**	$17,314
Effect of 8.25% Convertible debentures	**15**	19	**31**	37
Adjusted numerator — Diluted	**$3,535**	$3,359	**$17,298**	$17,351
Reconciliation of Denominator:				
Weighted shares outstanding — Basic	**9,557,707**	9,467,222	**9,546,606**	9,443,708
Effect of dilutive securities:				
Share-based Compensation	**20,699**	3,347	**21,958**	19,437
8.25% Convertible debentures	**72,481**	86,783	**73,810**	87,525
Adjusted denominator — Diluted	**9,650,887**	9,557,352	**9,642,374**	9,550,670
Diluted Earnings Per Share	**$0.37**	$0.35	**$1.79**	$1.82

3. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective Public Service Commission ("PSC"); Eastern Shore Natural Gas Company ("Eastern Shore"), our natural gas transmission operation, is subject to regulation by the Federal Energy Regulatory Commission ("FERC"); and Peninsula Pipeline Company, Inc. ("Peninsula Pipeline") is subject to regulation by the Florida Public Service Commission ("Florida PSC"). Chesapeake's Florida natural gas distribution division and the natural gas and electric distribution operations of Florida Public Utilities Company ("FPU") continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

Capacity Release: On September 2, 2008, our Delaware division filed with the Delaware Public Service Commission ("Delaware PSC") its annual Gas Sales Service Rates ("GSR") Application, seeking approval to change its GSR, effective November 1, 2008. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, which included the Delaware PSC, our Delaware division and the Division of the Public Advocate. As part of the settlement agreement, the parties agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, Peninsula Energy Services Company, Inc. ("PESCO"). On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates under asymmetrical pricing principles and the amount actually received by the Delaware division for capacity released to PESCO.

The Hearing Examiner also recommended that the Delaware PSC require us to adhere to asymmetrical pricing principles in all future capacity releases by the Delaware division to PESCO, if any. If the Hearing Examiner's refund recommendation for past capacity releases were ultimately approved without modification by the Delaware PSC, 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, which we estimated to be approximately $700,000, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC's capacity release rules. On February 18, 2010, we filed exceptions to the Hearing Examiner's recommendations.

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

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

On June 29, 2011, the Delaware Attorney General filed an appeal with the Delaware Supreme Court, asking it to review the Delaware Superior Court's decision affirming the Delaware PSC decision with regard to refunds for past capacity releases. The Delaware Attorney General was substituted in the case for the Division of the Public Advocate in the period between when the former Public Advocate retired and a new Public Advocate was appointed by the Governor. On July 12, 2011, the Delaware division filed a Notice of Cross Appeal with the Delaware Supreme Court, asking it to overturn the Superior Court's decision with regard to the Delaware PSC's decision on future capacity releases to PESCO. We have not accrued any contingent liability related to potential refunds for past capacity releases. We anticipate that the Delaware Supreme Court will render a decision sometime in the first half of 2012. In addition, due to the ongoing legal proceedings, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. Since the Delaware PSC's Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

Chesapeake's Delaware division also had developments in the following matters with the Delaware PSC:

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

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

Maryland

On December 14, 2010, 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 the Maryland division during the 12 months ended September 30, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division's four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

On March 2, 2011, the Maryland division filed with the Maryland PSC an application for the approval of a franchise executed between the Maryland division and the Board of County Commissioners of Cecil County, Maryland. In this franchise agreement, the County granted the Maryland division a 50-year, non-exclusive, franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Cecil County. On April 11, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Cecil County, subject to no adverse comments being received within 30 days after the issuance of the Order. On May 10, 2011, comments opposing the application were filed by Pivotal Utility Holdings, Inc. d/b/a Elkton Gas ("Pivotal"). Pivotal also provides natural gas service to customers in a portion of Cecil County. On June 8, 2011, the Maryland PSC granted the Maryland division the authority to exercise its franchise in a majority of the area requested in the Maryland division's application. The approval for a small portion of the area within the requested franchise area, which is closest to the area served by Pivotal, has been withheld until an evidentiary hearing is convened. It is anticipated that the Maryland PSC will render a decision on the remaining area in the fourth quarter of 2011 or the first quarter of 2012.

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

Florida

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

If the Florida PSC approves recovery of the acquisition adjustment and merger-related costs, we would be able to classify these amounts as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, we would calculate our rate of return based upon this higher level of investment which effectively enables us to earn a return on this investment. We would also be able to amortize the acquisition adjustment and merger-related costs over thirty and five years, respectively. Amortization expense would be included in the calculation of our rates.

Our earnings may be reduced by as much as $1.6 million annually for the amortization expense (approximately $1.3 million is non-tax-deductible) until 2014 and $1.1 million annually (non-tax deductible) thereafter until 2039. This amortization expense would be a non-cash charge, and the net effect of the recovery would be positive cash flow. Over the long-term, however, the inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have otherwise been able to achieve.

If the Florida PSC does not allow recovery of the acquisition adjustment and merger-related costs, there is some likelihood that we would have to reduce rates in the State of Florida, which would adversely affect our future earnings.

We continue to maintain a $750,000 accrual, which was recorded in 2010 based on management's assessment of FPU's earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in this filing.

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

In accordance with the terms of the Franchise Agreement, FPU developed reasonable TOU and interruptible rates and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an Order approving FPU's petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna has objected to the proposed rates and has filed a petition protesting the entry of the Florida PSC's Order. On March 17, 2011, FPU filed a Motion to Dismiss the petition by the City of Marianna and requested oral argument. On June 14, 2011, the Florida PSC granted FPU's request for oral argument and on July 5, 2011, issued an Order approving FPU's Motion to Dismiss the protest by the City of Marianna, without prejudice. On July 25, 2011, the City of Marianna filed an amended petition protesting the entry of the Florida PSC's Order.

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

On April 7, 2011, FPU filed a petition for approval of a mid-course reduction to its Northwest Division fuel rates based on two factors: 1) the previously discussed amendment to the Generation Services Agreement with Gulf Power; and 2) a weather-related increase in sales resulting in an accelerated collection of prior year's under-recovered costs. Pursuant to its Order dated July 5, 2011, the Florida PSC approved the petition, which is projected to reduce customers' fuel rates by approximately 10 percent per month.

As disclosed in Note 5, "Other Commitments and Contingencies," to the unaudited condensed consolidated financial statements, the City of Marianna, on March 2, 2011, filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU's property in the City of Marianna in accordance with the terms of the Franchise Agreement. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegation by the City of Marianna and asserted several affirmative defenses.

Eastern Shore

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

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

Rate Case Filing: On December 30, 2010, Eastern Shore filed with the FERC a base rate proceeding in compliance with the terms of the settlement in its prior base rate proceeding. The rate filing reflects increases in operating and maintenance expenses, depreciation expense, and a return on existing and new gas plant facilities expected to be placed into service before June 30, 2011. The FERC issued a notice of the filing on January 3, 2011. Protests were received from several interested parties, and other parties intervened in the proceeding. On January 31, 2011, the FERC issued its Order accepting the filing and suspending its effectiveness for the full five-month period permitted under the Natural Gas Act. The discovery process commenced on February 22, 2011, and FERC Staff performed an on-site audit on March 16-17, 2011. Settlement conferences involving Eastern Shore, FERC Staff and other interested parties were held beginning in April and have extended through early August 2011. Eastern Shore expects the base rate proceeding to be resolved in 2011.

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

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

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

Eastern Shore also had developments in the following FERC matters:

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

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

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

4. Environmental Commitments and Contingencies

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

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

As of June 30, 2011, we had approximately $11.2 million in environmental liabilities related to all of FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates. Approximately $8.1 million of FPU's expected environmental costs have been recovered from insurance and customers through rates as of June 30, 2011. We also had approximately $5.9 million in regulatory assets for future recovery of environmental costs from FPU's customers.

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. Pursuant to a Consent Order between FPU and the Florida Department of Environmental Protection ("FDEP"), effective April 8, 1991, FPU is required to complete the delineation of soil and groundwater impacts at the site, and implement an effective remedy.

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

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

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

FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP's conditions for approval. The operations on the east parcel have been relocated, and the structures removed. New monitoring wells and Air Sparging and Soil-Vapor Extraction ("AS/SVE") test wells were installed on the east parcel in May of 2011. The initial round of SVE and sparging pilot testing was completed in July of 2011, and the results of the testing are currently being analyzed.

Estimated costs of remediation for the West Palm Beach site range from approximately $4.9 million to $13.1 million. This estimate does not include any costs associated with relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

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

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In late September 2006, the United States 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 EPA projected the total estimated remediation costs for this site to be approximately $12.9 million.

In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13 million, or $650,000. As of June 30, 2011, FPU has paid $650,000 to the Sanford Group escrow account for its share of the funding requirements.

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

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

As of June 30, 2011, FPU's remaining share of remediation expenses, including attorneys' fees and costs, is estimated to be $20,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of June 30, 2011.

Key West, Florida

FPU formerly owned and operated an MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is requesting implementation of additional fieldwork which FDEP believes is warranted for the site.

FPU and the current site owner have had several discussions regarding the approach to be taken with FDEP and the proposed scope of work. Representatives of FPU, FDEP and the current site owner participated in a teleconference on July 7, 2011. During that call, the scope of work was tentatively agreed upon, and FDEP agreed to proceed without using a consent order. FPU and the current site owner will submit a work plan and schedule to FDEP in August of 2011. Total potential costs for investigation and remediation are projected to be $153,000.

Pensacola, Florida
FPU formerly owned and operated an MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation ("FDOT"). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action ("NFA") determination for the site, which must include a requirement for institutional and engineering controls. On November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for that portion of the property currently owned by FDOT. FPU, FDOT and the City of Pensacola are working together to obtain a restrictive covenant that is acceptable to FDEP to complete closure of the site, and it is anticipated that no further monitoring will be required on the site. FPU's total remaining consulting and remediation costs for this site are projected to be $5,000.

In addition, we had $284,000 in environmental liabilities at June 30, 2011, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of June 30, 2011, we had approximately $1.2 million in regulatory and other assets for future recovery through rates. The following discussion provides details on MGP sites for Chesapeake's Maryland and Florida divisions:

Salisbury, Maryland
We have substantially completed remediation of a site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an 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 permanently decommission the AS/SVE system and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery.

Through June 30, 2011, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies related to this site. We have recovered approximately $2.3 million through insurance proceeds or in rates, and $609,000 is expected to be recovered through future rates.

Winter Haven, Florida
The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a Consent Order entered into with the FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. In 2001, FDEP approved a RAP requiring construction and operation of a Bio-Sparging and 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. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. The Seventeenth Semi-Annual RAP Implementation Status Report was submitted to FDEP in June 2011. The groundwater sampling results through June 2011 show a continuing reduction in contaminant concentrations and indicate that the recent treatment system modifications and upgrades have had a beneficial impact on the rate of reduction. At present, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the BS/SVE treatment system. The total expected cost of operating and monitoring the system is approximately $46,000.

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

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

Through June 30, 2011, we have incurred and paid approximately $1.7 million for remedial activities at this site, and we have estimated and accrued for additional future costs of $284,000. We have recovered through rates $1.4 million of the costs to remediate the Winter Haven site and continue to expect that the remaining $542,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

Other

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

5. Other Commitments and Contingencies

Litigation

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

On March 2, 2011, the City of Marianna, Florida filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the City of Marianna to provide electric service to customers within and without the City of Marianna by failing: (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU's customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of

Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

Natural Gas, Electric and Propane Supply

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

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

In May 2011, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2012.

As discussed in Note 3 "Rates and Other Regulatory Activities," on January 25, 2011, FPU entered into an amendment to its Generation Services Agreement with Gulf Power, which reduces the capacity demand quantity and provides the savings necessary to support the TOU and interruptible rates for the customers in the City of Marianna, both of which were approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019.

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU's electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. As of June 30, 2011, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has previously authorized the Company to issue up to $35 million of corporate guarantees or letters of credit on behalf of our subsidiaries. On March 2, 2011, the Board increased this limit from $35 million to $45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at June 30, 2011 was $25.6 million, with the guarantees expiring on various dates through December 2011.

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

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $441,000, which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed the letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of June 30, 2011. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.5 million to Texas Eastern Transmission LP ("TETLP") related to the Precedent Agreement, which is further described below.

Agreements for Access to New Natural Gas Supplies

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

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

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

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP's pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP's pre-service costs could be approximately $8.6 million as of June 30, 2011. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2011, our proportionate share could be as much as approximately $50 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP's pre-service costs is remote.

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

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with Eastern Shore to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. As discussed in Note 3, "Rates and Other Regulatory Activities," to the unaudited condensed consolidated financial statements, Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transportation service on this extension is Eastern Shore's current tariff rate for service in that area.

TETLP is proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project, including, but not limited to, approval by the FERC. TETLP is expecting the FERC approval by the end of 2011. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or Eastern Shore.

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

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing a sales tax audit in Florida. As of June 30, 2011, we maintained an accrual of $698,000 related to additional sales taxes and gross receipts taxes owed to various states, all of which were recorded in 2010.

Other Contingency

As of June 30, 2011, we maintained a $750,000 accrual, which was recorded in 2010 based on management's assessment of FPU's earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in the "Come-Back" filing (See Note 3, "Rates and Other Regulatory Activities," to the unaudited condensed consolidated financial statements for further discussion).

6. Segment Information

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

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

The following table presents information about our reportable segments.

For the Periods Ended June 30,	Three Months Ended 2011	Three Months Ended 2010	Six Months Ended 2011	Six Months Ended 2010
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy	**$54,011**	$52,543	**$138,695**	$143,845
Unregulated Energy	**29,692**	24,494	**88,442**	83,521
Other	**3,128**	3,024	**6,292**	5,955
Total operating revenues, unaffiliated customers	**$86,831**	$80,061	**$233,429**	$233,321
Intersegment Revenues [1]				
Regulated Energy	**$316**	$197	**$634**	$522
Unregulated Energy	**-**	121	**-**	364
Other	**195**	259	**389**	447
Total intersegment revenues	**$511**	$577	**$1,023**	$1,333
Operating Income				
Regulated Energy	**$7,863**	$8,308	**$24,171**	$25,824
Unregulated Energy	**4**	(791)	**8,518**	6,969
Other and eliminations	**(91)**	244	**(74)**	366
Total operating income	**7,776**	7,761	**32,615**	33,159
Other income, net of other expenses	**27**	(11)	**50**	103
Interest	**2,114**	2,305	**4,265**	4,667
Income taxes	**2,169**	2,105	**11,133**	11,281
Net income	**$3,520**	$3,340	**$17,267**	$17,314

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

	June 30, 2011	December 31, 2010
(in thousands)		
Identifiable Assets		
Regulated energy	**$517,737**	$520,192
Unregulated energy	**111,357**	113,039
Other	**31,395**	37,762
Total identifiable assets	**$660,489**	$670,993

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

7. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and six months ended June 30, 2011 and 2010 are set forth in the following table:

For the Three Months Ended June 30,	Chesapeake Pension Plan 2011	Chesapeake Pension Plan 2010	FPU Pension Plan 2011	FPU Pension Plan 2010	Chesapeake SERP 2011	Chesapeake SERP 2010	Chesapeake Postretirement Plan 2011	Chesapeake Postretirement Plan 2010	FPU Medical Plan 2011	FPU Medical Plan 2010
(in thousands)										
Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27	$ 27
Interest Cost	130	144	672	637	27	34	15	31	39	34
Expected return on plan assets	(101)	(106)	(684)	(619)	-	-	-	-	-	-
Amortization of prior service cost	(2)	(2)	-	-	5	5	-	-	-	-
Amortization of net loss	39	39	-	-	9	14	-	14	5	-
Net periodic cost (benefit)	66	75	(12)	18	41	53	15	45	71	61
Amortization of pre-merger regulatory asset	-	-	191	190	-	-	-	-	2	2
Total periodic cost	$ 66	$ 75	$ 179	$ 208	$ 41	$ 53	$ 15	$ 45	$ 73	$ 63

For the Six Months Ended June 30,	Chesapeake Pension Plan 2011	Chesapeake Pension Plan 2010	FPU Pension Plan 2011	FPU Pension Plan 2010	Chesapeake SERP 2011	Chesapeake SERP 2010	Chesapeake Postretirement Plan 2011	Chesapeake Postretirement Plan 2010	FPU Medical Plan 2011	FPU Medical Plan 2010
(in thousands)										
Service Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53	$ 55
Interest Cost	260	289	1,343	1,275	54	68	30	61	78	68
Expected return on plan assets	(202)	(212)	(1,368)	(1,238)	-	-	-	-	-	-
Amortization of prior service cost	(3)	(3)	-	-	10	10	-	-	-	-
Amortization of net loss	78	78	-	-	19	30	-	29	10	-
Net periodic cost (benefit)	133	152	(25)	37	83	108	30	90	141	123
Settlement expense	217	-	-	-	-	-	-	-	-	-
Amortization of pre-merger regulatory asset	-	-	381	507	-	-	-	-	4	5
Total periodic cost	$ 350	$ 152	$ 356	$ 544	$ 83	$ 108	$ 30	$ 90	$ 145	$ 128

We expect to record pension and postretirement benefit costs of approximately $1.9 million for 2011. Included in that amount is a pension settlement expense of $217,000 recorded during the first six months of 2011 related to a lump-sum pension distribution of $844,000 from the Chesapeake Pension Plan in January 2011 and $219,000 of settlement expense in July 2011 related to a lump-sum distribution from the Chesapeake SERP. Also included in that amount is $769,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated energy operations of the changes in funded status that occurred but were not recognized as part of net periodic benefit costs prior to the merger. This was deferred as a regulatory asset by FPU prior to the merger to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was $6.3 million and $6.7 million at June 30, 2011 and December 31, 2010, respectively.

During the six months ended June 30, 2011, we contributed $68,000 to the Chesapeake pension plan. We also contributed $292,000 and $555,000 to the FPU pension plan during the three and six months ended June 30, 2011, respectively. We expect to contribute $955,000 and $1.3 million to the Chesapeake and FPU pension plans, respectively, during the year 2011.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three and six months ended June 30, 2011, were $22,000 and $45,000, respectively; for the year 2011, such benefits paid are expected to be approximately $853,000, which includes the expected lump-sum distribution of $765,000 as mentioned above. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three and six months ended June 30, 2011, totaled $22,000 and $47,000, respectively; for the year 2011, we have estimated that approximately $96,000 will be paid for such benefits. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three and six months ended June 30, 2011, totaled $24,000 and $35,000, respectively; for the year 2011, we have estimated that approximately $158,000 will be paid for such benefits.

In connection with the lump-sum pension distribution from the Chesapeake Pension Plan in January 2011 and the Chesapeake SERP in July 2011, and related settlement accounting, we re-measured the assets and obligations of the Chesapeake Pension Plan. The assumptions used for the discount rate to calculate the benefit obligation remained unchanged at five percent. The average expected return on plan assets also did not change and remained at six percent.

8. Investments

The investment balance at June 30, 2011, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan, (b) a Rabbi Trust related to a stay bonus agreement with a former executive, and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. Any unrealized gains and losses, net of other expenses, are included in other income in the condensed consolidated statements of income. We also have recorded an associated liability that is adjusted each month for the gains and losses incurred by the Rabbi Trusts. At June 30, 2011 and December 31, 2010, total investments had a fair value of $4.1 million and $4.0 million, respectively.

9. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan ("DSCP") and the Performance Incentive Plan ("PIP"), respectively. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is primarily 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 awards granted under the DSCP and the PIP for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended		Six Months Ended	
For the Periods Ended June 30,	**2011**	**2010**	**2011**	**2010**
(in thousands)				
Directors Stock Compensation Plan	**$102**	$71	**$185**	$135
Performance Incentive Plan	**274**	208	**520**	477
Total compensation expense	**376**	279	**705**	612
Less: tax benefit	**151**	112	**283**	245
Share-Based Compensation amounts included in net income	**$225**	$167	**$422**	$367

<u>Directors Stock Compensation Plan</u>

Shares granted under the DSCP are issued in advance of the directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense of the shares issued and amortize the expense equally over a service period of one year. In May 2011, each of our non-employee directors received an annual retainer of 900 shares of common stock under the DSCP. A summary of stock activity under the DSCP during the six months ended June 30, 2011 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2010	-	-
Granted[1]	11,104	$41.03
Vested	11,104	$41.03
Forfeited	-	-
Outstanding — June 30, 2011	-	-

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

At June 30, 2011, there was $369,000 of unrecognized compensation expense related to the DSCP awards. This expense is expected to be recognized over the remaining directors' service periods ending as of the 2012 Annual Meeting.

Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the six months ended June 30, 2011:

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2010	101,150	$28.78
Granted	41,664	40.16
Vested	31,400	27.63
Forfeited	24,000	29.31
Expired	-	-
Outstanding — June 30, 2011	87,414	$34.47

In January 2011, the Board of Directors granted awards under the PIP for 41,664 shares.. The shares granted in January 2011 are multi-year awards, of which 10,500 shares will vest at the end of the two-year service period, or December 31, 2012. The remaining 31,164 shares will vest at the end of the three-year service period, or December 31, 2013. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which comprised both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

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

At June 30, 2011, the aggregate intrinsic value of the PIP awards was $1.9 million.

10. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered "normal purchases and sales" and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of June 30, 2011, our natural gas, electric and propane distribution operations did not have any outstanding derivative contracts.

Xeron, our propane wholesale and marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of June 30, 2011, we had the following outstanding trading contracts which we accounted for as derivatives:

At June 30, 2011	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	9,240,000	$1.3900 — $1.5700	$1.5005
Purchase	8,106,000	$1.3344 — $1.5850	$1.4878

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire during or prior to the first quarter of 2012.

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

Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of June 30, 2011 and December 31, 2010, are the following:

	Asset Derivatives		
		Fair Value	
(in thousands)	Balance Sheet Location	June 30, 2011	December 31, 2010
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$335	$1,642
Put option [1]	Mark-to-market energy assets	-	-
Total asset derivatives		$335	$1,642

	Liability Derivatives		
		Fair Value	
(in thousands)	Balance Sheet Location	June 30, 2011	December 31, 2010
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$216	$1,492
Total liability derivatives		$216	$1,492

(1) We purchased a put option for the Pro-Cap (propane price cap) Plan in October 2010. The put option, which expired in January and February 2011, had a fair value of $0 at December 31, 2010.

The effects of gains and losses from derivative instruments on the condensed consolidated statements of income are the following:

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	(Loss) on Derivatives	2011	2010	2011	2010
Derivatives not designated as hedging instruments:					
Put Option[(1)(2)]	Cost of Sales	$ -	$ -	$ -	$ -
Unrealized gain on forward contracts	Revenue	(112)	160	(30)	374
Total		$ (112)	$ 160	$ (30)	$ 374

[(1)] We purchased a put option for the Pro-Cap Plan in October 2010. The put option, which expired in January and February 2011, had a fair value of $0 at December 31, 2010.

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

The effects of trading activities on the condensed consolidated statements of income are the following:

	Location in the	Three months ended June 30,		Six months ended June 30,	
(in thousands)	Statement of Income	2011	2010	2011	2010
Realized gains on forward contracts	Revenue	$647	$60	$1,554	$738
Changes in mark-to-market energy assets	Revenue	(112)	160	(30)	374
Total		$535	$220	$1,524	$1,112

11. Fair Value of Financial Instruments

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

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

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

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at June 30, 2011:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments - equity securities	$1,705	$1,705	$-	$-
Investments - other	$2,404	$2,404	$-	$-
Mark-to-market energy assets	$335	$-	$335	$-
Liabilities:				
Mark-to-market energy liabilities	$216	$-	$216	$-

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

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments - equity securities	$1,515	$1,515	$-	$-
Investments - other	$2,521	$2,521	$-	$-
Mark-to-market energy assets, including put option	$1,642	$-	$1,642	$-
Liabilities:				
Mark-to-market energy liabilities	$1,492	$-	$1,492	$-

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of June 30, 2011 and December 31, 2010:

Level 1 Fair Value Measurements:
Investments- equity securities - The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.
Investments- other - The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

Level 2 Fair Value Measurements:
Mark-to-market energy assets and liabilities - These forward contracts are valued using market transactions in either the listed or over the counter ("OTC") markets.

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

At June 30, 2011, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

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

At June 30, 2011, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $126.3 million, compared to a fair value of $145.0 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, 2010, long-term debt, including the current maturities, had a carrying value of $98.9 million, compared to the estimated fair value of $113.4 million.

12. Long-Term Debt

Our outstanding long-term debt is shown below:

	June 30, 2011	December 31, 2010
(in thousands)		
FPU secured first mortgage bonds [(A)]:		
9.57% bond, due May 1, 2018	**$6,346**	$7,248
10.03% bond, due May 1, 2018	**3,490**	3,986
9.08% bond, due June 1, 2022	**7,956**	7,950
Uncollateralized senior notes:		
6.85% note, due January 1, 2012	**1,000**	1,000
7.83% note, due January 1, 2015	**8,000**	8,000
6.64% note, due October 31, 2017	**19,091**	19,091
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
5.68% note, due June 30, 2026	**29,000**	-
Convertible debentures:		
8.25% due March 1, 2014	**1,221**	1,318
Promissory note	**215**	265
Total long-term debt	**126,319**	98,858
Less: current maturities	**(9,196)**	(9,216)
Total long-term debt, net of current maturities	**$117,123**	$89,642

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

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2010, including the audited consolidated financial statements and notes thereto.

Safe Harbor for Forward-Looking Statements

We make statements in this Quarterly Report on Form 10-Q that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as "project," "believe," "expect," "anticipate," "intend," "plan," "estimate," "continue," "potential," "forecast" or other similar words, or future or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries (including deregulation);
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates;
- the loss of customers due to government mandated sale of our utility distribution facilities;
- 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;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs;
- changes in technology affecting our advanced information services business; and
- operation and litigation risks that may not be covered by insurance.

Introduction

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

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

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

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of natural gas and propane is normally highest due to colder temperatures.

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

Results of Operations for the Quarter Ended June 30, 2011

Overview and Highlights

Our net income for the quarter ended June 30, 2011 was $3.5 million, or $0.37 per share (diluted). This represents an increase of $180,000, or $0.02 per share (diluted), compared to a net income of $3.3 million, or $0.35 per share (diluted), as reported in the same period in 2010.

(in thousands except per share)

For the Three Months Ended June 30,	2011	2010	Increase (decrease)
Business Segment:			
Regulated Energy	**$7,863**	$8,308	($445)
Unregulated Energy	**4**	(791)	795
Other	**(91)**	244	(335)
Operating Income	**7,776**	7,761	15
Other Income	**27**	(11)	38
Interest Charges	**2,114**	2,305	(191)
Income Taxes	**2,169**	2,105	64
Net Income	**$3,520**	$3,340	$180
Earnings Per Share of Common Stock			
Basic	**$0.37**	$0.35	$0.02
Diluted	**$0.37**	$0.35	$0.02

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results during the second quarter of 2011. More detailed analysis of our results by segment is provided in the following section.

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

Eastern Shore, our natural gas transmission subsidiary, generated gross margin of $542,000 in the second quarter of 2011 from new transportation services associated with its eight-mile mainline extension to interconnect with TETLP's pipeline system. These services commenced in January 2011 and have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, and an estimated gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million annually thereafter.

14 large commercial and industrial customers added by the Delmarva natural gas operation since July 2010 generated $261,000 in additional gross margin during the second quarter of 2011. These new customers are expected to generate annual margin of $1.1 million in 2011, compared to $196,000 of gross margin generated from these customers in 2010. Also generating additional gross margin of $105,000 for the second quarter of 2011 was a three-percent growth in residential customers for the Delmarva natural gas distribution operation.

The Florida natural gas distribution operations generated $376,000 from one-percent growth in residential customers and three-percent growth in commercial customers in the second quarter of 2011, compared to the same quarter in 2010. In addition, 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated $142,000 of additional gross margin during the quarter.

We are continuing our efforts to extend natural gas service to Lewes, Delaware and Cecil and Worcester Counties, Maryland. We signed service agreements in March 2011 with Beebe Medical Center and SPI Pharma, both located in Lewes, Delaware, with natural gas service expected to commence to these customers in the third and fourth quarters of 2011, respectively. Gross margin from these customers is expected to equate to gross margin generated by approximately 1,000 residential customers. We have obtained the necessary natural gas franchises from Cecil and Worcester Counties, Maryland and the approval from the Maryland PSC to exercise those franchises, except for the final determination of the service boundary in a small portion of the franchise area in Cecil County.

Propane Prices. Higher price volatility and trading volumes in Xeron, our wholesale marketing subsidiary, resulted in a 56-percent increase in its trading volumes during the second quarter of 2011, compared to the same quarter in 2010, and generated $314,000 of additional gross margin.

Our propane distribution operations generated additional gross margin of $658,000 from higher margins per gallon in the second quarter of 2011, compared to the same quarter in 2010. Propane retail margins per gallon on the Delmarva Peninsula during the second quarter of 2011 returned to more normal levels, compared to the lower margins per gallon reported during the second quarter of 2010 caused by the higher cost of spot purchases during the peak heating season. Propane retail margins per gallon in Florida also increased in the second quarter of 2011, compared to the same quarter in 2010, as we continued to adjust our retail pricing in response to market conditions.

Rates and Regulatory Matters. Eastern Shore's base rate proceeding, which was filed with the FERC on December 30, 2010, is still underway. Eastern Shore expects this proceeding to be completed in 2011. The "Come-Back" filing in Florida, which includes our request for recovery, through rates, of approximately $34.2 million in acquisition adjustment and $2.2 million in merger-related costs, is also still underway. See Note 3, "Rates and Other Regulatory Activities," to the unaudited condensed consolidated financial statements for further discussion.

Advanced Information Services. BravePoint, our advanced information services subsidiary, reported $188,000 in operating loss in the second quarter of 2011, compared to operating income of $230,000 reported in the same quarter in 2010. BravePoint's operating results in the second quarter of 2011 reflect approximately $341,000 in additional costs associated with the initial roll-out and implementation of a new product, ProfitZoom™. BravePoint completed the first successful implementation of ProfitZoom™ in July 2011. At present, BravePoint has three customers, which have implemented, or are in the process of implementing, this new product and has several outstanding sales proposals under consideration by other customers. ProfitZoom™ is an integrated system designed specifically for the fire protection and specialty contracting industries, which includes a comprehensive suite of financial, job costing and service management modules, and is a successor product to another software solution that BravePoint previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom™ product in 2009.

Other Operating Expenses. Our other operating expenses increased by $2.5 million in the second quarter of 2011, compared to the same quarter in 2010. Included in this increase are $808,000 in non-recurring charges incurred during the second quarter of 2011, which were comprised of $259,000 in additional marketing and development costs of ProfitZoom™, and $549,000 in one-time charges in May 2011 associated with the voluntary workforce reduction of 31 employees in Florida as we continue to integrate our Florida operations. The voluntary workforce reduction in Florida is expected to generate $500,000 in cost savings in 2011 and $800,000 in annual savings thereafter.

The remaining $1.7 million of the increase in other operating expenses, or a six-percent increase compared to other operating expenses during the second quarter of 2010, was attributable to the following factors:

- $558,000 in increased payroll and benefits expense, excluding one-time charges associated with the voluntary workforce reduction, due primarily to enhanced benefits offered to FPU and BravePoint employees and higher accruals for performance incentive compensation;
- Increased regulatory, legal and other costs related to our regulated energy businesses, including $316,000 of additional costs associated with our electric franchise dispute in Marianna, Florida and $83,000 in costs with respect to our "Come-Back" filing in Florida and the rate case proceeding for Eastern Shore;

- $258,000 in higher depreciation expense and asset removal costs in our regulated energy businesses from capital investments made since the second half of 2010;
- $153,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with pipeline regulatory requirements; and
- $79,000 of other operating expenses during the second quarter of 2011 from the purchase of the operating assets of Indiantown Gas Company in August 2010.

Both the "Come-Back" filing and the Eastern Shore rate case proceeding are expected to be resolved in 2011. Eastern Shore projects pipeline integrity expenditures to be at about the same level in 2011 and 2012 and projects a decrease in such expenditures in 2013.

Regulated Energy

For the Three Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day and customer information)			
Revenue	**$54,327**	$52,740	$1,587
Cost of sales	**24,882**	24,625	257
Gross margin	**29,445**	28,115	1,330
Operations & maintenance	**15,552**	14,074	1,478
Depreciation & amortization	**4,020**	3,754	266
Other taxes	**2,010**	1,979	31
Other operating expenses	**21,582**	19,807	1,775
Operating Income	**$7,863**	$8,308	($445)

Weather and Customer analysis			
Delmarva Peninsula			
Heating degree-days ("HDD"):			
Actual	**382**	428	(46)
10-year average	**487**	495	(8)
Per residential customer added:			
Estimated gross margin	**$375**	$375	$0
Estimated other operating expenses	**$111**	$105	$6
Florida			
HDD:			
Actual	**14**	9	5
10-year average	**30**	33	(3)
Cooling degree-days:			
Actual	**1,027**	1,037	(10)
10-year average	**894**	880	14
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**48,660**	47,431	1,229
Florida natural gas distribution	**61,659**	60,580	1,079
Florida electric distribution	**23,593**	23,585	8
Total	**133,912**	131,596	2,316

Operating income for the regulated energy segment decreased by approximately $445,000, or five percent, in the second quarter of 2011, compared to the same quarter in 2010. An increase in gross margin of $1.3 million, offset by an increase in other operating expense of $1.8 million, resulted in the decrease in operating income.

Gross Margin
Gross margin for our regulated energy segment increased by $1.3 million, or five percent, in the second quarter of 2011 compared to the same quarter in 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $426,000 in the second quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Customer growth generated a $400,000 increase in gross margin in the second quarter of 2011, compared to the same quarter in 2010. Commercial and industrial customer growth, due primarily to $261,000 in additional gross margin generated from 14 large commercial and industrial customers added since July 2010, generated $295,000 of this increase. These 14 new large commercial and industrial customers are expected to generate annual gross margin of $1.1 million in 2011. The same customers generated $196,000 of gross margin following their addition in the second half of 2010. Three-percent growth in residential customers generated an additional $105,000 in gross margin.

- The remaining increase in gross margin of $26,000 was attributable to increased non-weather-related customer consumption, offset partially by a decrease from a change in customer rates and rate classes.

Gross margin for our Florida natural gas distribution operation increased by $141,000 in the second quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- One-percent growth in residential customers and three-percent growth in commercial customers generated additional gross margin of $376,000 in the second quarter of 2011, compared to the same quarter in 2010.

- 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated $142,000 in gross margin in the second quarter of 2011.

- These increases in gross margin in the second quarter were partially offset by decreased gross margin of $377,000, primarily attributable to lower customer consumption during the second quarter, compared to the same quarter in 2010.

Our natural gas transmission operations achieved gross margin growth of $761,000 in the second quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- New transportation services associated with Eastern Shore's eight-mile mainline extension to interconnect with TETLP's pipeline system generated an additional $542,000 of gross margin in the second quarter. These new services commenced in January 2011 and have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, and an estimated annual gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million annually thereafter.

- New transportation services implemented by Eastern Shore in May 2010 and November 2010 as result of its system expansion projects generated an additional $103,000 of gross margin in the second quarter of 2011, compared to the same quarter in 2010. These expansions added 2,666 Mcfs per day and an estimated annual gross margin of $574,000 in 2011. In 2010, these projects generated $216,000 of gross margin, of which $40,000 was recorded in the second quarter of 2010.

- Eastern Shore entered into two additional transportation services agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and other one for the period of November 2011 through October 2012 for an additional 9,192 Mcfs. These services generated additional gross margin of $61,000 in the second quarter of 2011 and are expected to generate additional gross margin of $356,000 in 2011, $1.2 million in 2012 and $369,000 annually thereafter.

- The remaining gross margin increase of $55,000 was attributable primarily to higher volumes delivered to customers on a non-recurring basis during the second quarter.

Gross margin for our Florida electric distribution operation remained relatively unchanged with a slight increase of $2,000 in the second quarter of 2011, compared to the same quarter in 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $1.8 million, or nine percent, in the second quarter of 2011, compared to the same quarter in 2010, due largely to the following factors:

- One-time charges of $481,000 for the regulated energy businesses associated with the voluntary workforce reduction in Florida;
- Increased regulatory, legal and other costs, including $316,000 of additional costs associated with our electric franchise dispute in Marianna, Florida and $83,000 in costs associated with the "Come-Back" filing in Florida and the rate case proceeding for Eastern Shore;
- $258,000 in higher depreciation expense and asset removal costs from capital investments made since the second half of 2010;
- $153,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements; and
- $79,000 of other operating expenses associated with the purchase of the operating assets of Indiantown Gas Company in August 2010.

Other Development

In June 2011, Allen Family Foods, Inc. and related entities (collectively, "Allen") filed for bankruptcy. Our Delmarva natural gas distribution operation serves two of Allen's poultry facilities, one of which is included in our discussion of 14 new large commercial and industrial customers added since July 2010. Gross margin generated from our natural gas service to these two Allen facilities was approximately $94,000 and $24,000 for the three months ended June 30, 2011 and 2010, respectively, and approximately $211,000 and $51,000 for the first six months of 2011 and 2010, respectively. The total gross margin for 2010 from our natural gas service to these two facilities was approximately $156,000. As of June 30, 2011, we had approximately $40,000 in outstanding receivable balances with Allen. Since the bankruptcy filing, these two facilities have been sold to another poultry processor. We cannot predict the future plan for these two facilities by the new purchaser or the level of natural gas consumption, if any, at these two facilities in the future.

Unregulated Energy

For the Three Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day data)			
Revenue	**$29,692**	$24,615	$5,077
Cost of sales	**22,849**	19,068	3,781
Gross margin	**6,843**	5,547	1,296
Operations & maintenance	**5,692**	5,331	361
Depreciation & amortization	**807**	718	89
Other taxes	**340**	289	51
Other operating expenses	**6,839**	6,338	501
Operating Income (Loss)	**$4**	($791)	$795

Weather Analysis — Delmarva Peninsula			
Actual HDD	**382**	428	(46)
10-year average HDD	**487**	495	(8)

Operating income for the unregulated energy segment in the second quarter of 2011 was $4,000, an increase of $795,000, compared to an operating loss of $791,000 in the same quarter in 2010. The increase resulted from an increase in gross margin of $1.3 million, which was offset by an increase in other operating expense of $501,000.

Gross Margin
Gross margin for our unregulated energy segment increased by $1.3 million, or 23 percent, in the second quarter of 2011, compared to the same quarter in 2010.

Our Delmarva propane distribution operation generated an increase in gross margin of $481,000, or 21 percent, in the second quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Our Delmarva propane distribution operation generated additional gross margin of $220,000 due to higher margins per gallon in the second quarter of 2011, compared to the same quarter in 2010, as margins per gallon returned to more normal levels during the current quarter. Propane margins per gallon during the second quarter of 2010 were low, compared to historical levels, due to additional spot purchases at increased costs during the peak heating season to meet the weather-related increase in customer consumption. More normal temperatures and fewer spot purchases during 2011 resulted in margins per gallon returning to more normal levels in the second quarter of 2011.

- An increase in volumes sold in the second quarter of 2011, compared to the same period in 2010, generated additional gross margin of $109,000. This increase was attributable to the timing of deliveries to bulk customers, offset partially by a decrease in weather-related consumption due to the warmer temperatures on the Delmarva Peninsula.

- The remaining gross margin increase of $152,000 is due primarily to increased wholesale margins and higher fees generated from increased service work, continued growth and successful implementation of various customer loyalty programs.

Our Florida propane distribution operations generated increased gross margin of $302,000 in the second quarter of 2011, compared to the same quarter in 2010. Higher margins per gallon, as we continued to adjust our retail pricing in response to market conditions, generated $438,000 of additional gross margin. Also generating additional gross margin of $77,000 during the current quarter was a new propane rail terminal arrangement with a supplier from November 2010 to May 2011 to provide terminal and storage services. These additional gross margins were offset partially by a decrease in volume sold in the second quarter of 2011, compared to the same period in 2010.

Xeron, our propane wholesale marketing subsidiary, generated $314,000 of increase in gross margin during the second quarter of 2011, compared to the same quarter in 2010, due primarily to an increase in Xeron's trading activity by 56 percent in the second quarter of 2011, compared to the same period in 2010.

Gross margin generated by PESCO, our natural gas marketing subsidiary, increased by $291,000 in the second quarter of 2011 compared to the same quarter in 2010. This increase was due to favorable imbalance resolutions during the second quarter of 2011 with third-party intrastate pipelines, with which PESCO contracts for supply. Revenues generated from such favorable imbalance resolutions are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Merchandise sales in Florida decreased in the second quarter of 2011, compared to the same period in 2010, resulting in lower gross margin of $92,000.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $501,000 for the second quarter of 2011, compared to the same period in 2010, due primarily to: (a) increased payroll and benefit costs of $344,000, attributable primarily to higher accruals for performance incentive compensation; (b) increased vehicle expenses of $108,000 resulting from an increase in fuel prices; and (c) one-time charges of $67,000 for the unregulated energy businesses associated with the voluntary workforce reduction in Florida.

Other

For the Three Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands)			
Revenue	**$2,812**	$2,706	$106
Cost of sales	**1,571**	1,316	255
Gross margin	**1,241**	1,390	(149)
Operations & maintenance	**1,049**	910	139
Depreciation & amortization	**110**	73	37
Other taxes	**173**	163	10
Other operating expenses	**1,332**	1,146	186
Operating Income - Other	**(91)**	244	(335)
Operating Income - Eliminations	-	-	-
Operating Income	**($91)**	$244	($335)

Note: Eliminations are entries required to eliminate activities between business segments from the consolidated results.

Operating income for the "other" segment decreased by approximately $335,000 in the second quarter of 2011, compared to the same quarter in 2010, which was attributable to a gross margin decrease of $149,000, and an operating expense increase of $186,000.

Gross margin
The gross margin for our "other" segment decreased by $149,000 in the second quarter of 2011, compared to the same quarter in 2010, due primarily to BravePoint, our advanced information services subsidiary. Gross margin for BravePoint decreased by $114,000 as a result of decreased product sales, lower consulting margin and additional costs incurred during initial implementations of ProfitZoom™.

Other Operating expenses
Other operating expenses for our "other" segment increased by $186,000 in the second quarter of 2011, compared to the same quarter in 2010. Other operating expenses for BravePoint increased by $304,000, due primarily to $259,000 in additional marketing and development costs, as it began to roll out ProfitZoom™, and $116,000 in increased benefit costs. Benefit costs increased for BravePoint as Chesapeake adopted a safe harbor 401(k) plan design on January 1, 2011, which resulted in an increased 401(k) benefit for BravePoint employees in 2011. The increase in BravePoint's other operating expenses was partially offset by the absence in 2011 of $92,000 in merger-related costs in the second quarter of 2010.

Interest Expense
Interest expense for the quarter ended June 30, 2011 decreased by approximately $191,000, or eight percent, compared to the same quarter in 2010, due primarily to lower interest expenses on short-term borrowings and long-term debt. Short-term interest expense decreased by $42,000, which is largely attributable to lower rates on the $29.1 million term loan credit facility used to temporarily refinance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds in January 2010. Long-term interest expense decreased by $135,000 due to lower long-term debt as a result of scheduled principal payments.

On June 23, 2011, we issued $29 million of 5.68 percent unsecured senior notes to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement executed in June 2010. We used the proceeds to permanently refinance the redemption of the two series of FPU first mortgage bonds mentioned previously, which were temporarily refinanced using a short-term loan credit facility. Compared to interest expense incurred under the short-term loan credit facility during the first half of 2011, issuance of these senior notes will result in an increase in interest expense of $550,000 in the second half of 2011.

Income Taxes
We recorded an income tax expense of $2.2 million for the quarter ended June 30, 2011, compared to $2.1 million for the quarter ended June 30, 2010. The increase is attributable to increased earnings in the second quarter of 2011 compared to the same period in 2010.

Results of Operations for the Six Months Ended June 30, 2011

Overview and Highlights
Our net income during the six months ended June 30, 2011 was $17.3 million, or $1.79 per share (diluted). This represents a decrease of $0.03 per share (diluted), compared to $1.82 per share (diluted), as reported for the same period in 2010.

For the Six Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands, except per share)			
Business Segment:			
Regulated Energy	**$24,171**	$25,824	($1,653)
Unregulated Energy	**8,518**	6,969	1,549
Other	**(74)**	366	(440)
Operating Income	**32,615**	33,159	(544)
Other Income	**50**	103	(53)
Interest Charges	**4,265**	4,667	(402)
Income Taxes	**11,133**	11,281	(148)
Net Income	**$17,267**	$17,314	($47)
Earnings Per Share of Common Stock			
Basic	**$1.81**	$1.83	($0.02)
Diluted	**$1.79**	$1.82	($0.03)

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results during the first six months of 2011. More detailed analysis of our results by segment is provided in the following section.

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

Eastern Shore, our natural gas transmission subsidiary, generated gross margin of $1.1 million in the first six months of 2011 from new transportation services associated with its eight-mile mainline extension to interconnect with TETLP's system. These services commenced in January 2011 and have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, and an estimated gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million annually thereafter.

14 large commercial and industrial customers added by the Delmarva natural gas operation since July 2010 generated $509,000 in additional gross margin during the first six months of 2011. These new customers are expected to generate annual margin of $1.1 million in 2011, compared to $196,000 of gross margin generated from these customers in the second half of 2010. Also generating additional gross margin of $271,000 for the first six months of 2011 was a two-percent growth in residential customers for the Delmarva natural gas distribution operation.

The Florida natural gas distribution operations generated $576,000 from one-percent growth in residential customers and three-percent growth in commercial customers in the six months ended June 30, 2011, compared to the same period in 2010. In addition, 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated $325,000 of additional gross margin during the first half of 2011.

We are continuing our efforts to extend natural gas service to Lewes, Delaware and Cecil and Worcester Counties, Maryland. We signed service agreements in March 2011 with Beebe Medical Center and SPI Pharma, both located in Lewes, Delaware, with natural gas service expected to commence to these customers in the third and fourth quarters of 2011, respectively. Gross margin from these customers is expected to equate to gross margin generated by approximately 1,000 residential customers. We have obtained the necessary natural gas franchises from Cecil and Worcester Counties, Maryland and the approval from the Maryland PSC to exercise those franchises, except for the final determination of the service boundary in a small portion of the franchise area in Cecil County.

Weather. Warmer temperatures on the Delmarva Peninsula and in Florida during the first half of 2011, compared to the same period in 2010, particularly during the peak heating season, decreased consumer consumption of natural gas and electricity. Lower consumption, attributable primarily to warmer weather, decreased our period-over-period gross margin by approximately $2.4 million. Heating degree-days decreased by five percent, or 144 heating degree-days, on the Delmarva Peninsula and by 43 percent, or 408 heating degree-days, in Florida during the first six months of 2011, compared to the same period in 2010.

Propane Prices. Xeron, our wholesale marketing subsidiary, generated a period-over-period gross margin increase of $412,000, resulting from higher price volatility and a 50-percent increase in its trading activity during the first six months of 2011, compared to the same period in 2010.

The propane distribution operations generated additional gross margin of $980,000 from higher margins per gallon in the first six months of 2011, compared to the same period in 2010. Propane retail margins per gallon on the Delmarva Peninsula during the first half of 2011 returned to more normal levels, compared to the lower margins per gallon reported during the same period in 2010 caused by colder temperatures and the high cost of spot purchases during the peak heating season. Propane retail margins per gallon in Florida also increased in the first half of 2011, compared to the same period in 2010, as we continued to adjust our retail pricing in response to market conditions.

Rates and Regulatory Matters. Eastern Shore's base rate proceeding, which was filed with the FERC on December 30, 2010, is still underway. Eastern Shore expects this proceeding to be completed in 2011. The "Come-Back" filing in Florida, which includes our request for recovery, through rates, of approximately $34.2 million in acquisition adjustment and $2.2 million in merger-related costs, is also still underway. See Note 3, "Rates and Other Regulatory Activities," to the unaudited condensed consolidated financial statements for further discussion.

Advanced Information Services. BravePoint, our advanced information services subsidiary, reported $282,000 in operating loss in the six months ended June 30, 2011, compared to operating income of $265,000 reported in the same period in 2010. BravePoint's operating results for the six months ended June 30, 2011 reflected approximately $549,000 in additional costs associated with the initial roll-out and implementation of a new product, ProfitZoom™. BravePoint completed the first successful implementation of ProfitZoom™ in July 2011. At present, BravePoint has three customers, which have implemented, or are currently implementing, this new product and has several outstanding sales proposals under consideration by other potential customers. ProfitZoom™ is an integrated system designed specifically for the fire protection and specialty contracting industries, which includes a comprehensive suite of financial, job costing and service management modules, and is a successor product to another software solution previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom™ product in 2009.

Other Operating Expenses. Our other operating expenses increased by $3.4 million in the six months ended June 30, 2011, compared to the same period in 2010. Included in this increase are approximately $1.2 million in non-recurring charges incurred during the first six months of 2011, which were comprised of $439,000 in additional marketing and development costs of ProfitZoom™ and $788,000 in one-time charges associated with the voluntary workforce reduction in Florida and a pension settlement.

The remaining $2.2 million of the increase in other operating expenses, or a four-percent increase compared to other operating expenses during the first six months of 2010, was attributable to the following factors:

- $559,000 in higher depreciation expense and asset removal costs in our regulated energy businesses from capital investments made since the second half of 2010;

- Increased regulatory, legal and other costs related to our regulated energy businesses, including $316,000 of additional costs associated with our electric franchise dispute in Marianna, Florida and $137,000 in costs with respect to our "Come-Back" filing in Florida and the rate case proceeding for Eastern Shore;
- $416,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with pipeline regulatory requirements; and
- $147,000 of other operating expenses during the first six months of 2011 from the purchase of the operating assets of Indiantown Gas Company in August 2010.

Both the "Come-Back" filing and the Eastern Shore rate case proceeding are expected to be resolved in 2011. Eastern Shore projects pipeline integrity expenditures to be at about the same level in 2011 and 2012 and projects a decrease in such expenditures in 2013.

Regulated Energy

For the Six Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day and customer information)			
Revenue	**$139,329**	$144,367	($5,038)
Cost of sales	**72,872**	78,889	(6,017)
Gross margin	**66,457**	65,478	979
Operations & maintenance	**29,862**	27,889	1,973
Depreciation & amortization	**8,187**	7,478	709
Other taxes	**4,237**	4,287	(50)
Other operating expenses	**42,286**	39,654	2,632
Operating Income	**$24,171**	$25,824	($1,653)

Weather and Customer analysis			
Delmarva Peninsula			
Heating degree-days ("HDD"):			
Actual	**2,827**	2,971	(144)
10-year average	**2,863**	2,831	32
Per residential customer added:			
Estimated gross margin	**$375**	$375	$0
Estimated other operating expenses	**$111**	$105	$6
Florida			
HDD:			
Actual	**534**	942	(408)
10-year average	**594**	547	47
Cooling degree-days:			
Actual	**1,107**	1,040	67
10-year average	**961**	952	9
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**48,986**	47,808	1,178
Florida natural gas distribution	**61,603**	60,530	1,073
Florida electric distribution	**23,591**	23,558	33
Total	**134,180**	131,896	2,284

Operating income for the regulated energy segment decreased by approximately $1.7 million, or six percent, during the first six months of 2011, compared to the same period in 2010. An increase in gross margin of $979,000, offset by an increase in other operating expenses of $2.6 million, resulted in the decrease in operating income.

Gross Margin

Gross margin for our regulated energy segment increased by $979,000, or two percent, during the first six months of 2011, compared to the same period in 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $866,000 in the first six months of 2011, compared to the same period in 2010. The factors contributing to this increase were as follows:

- Customer growth generated an $855,000 increase in gross margin in the first six months of 2011, compared to the same period in 2010. Commercial and industrial customer growth, due primarily to $509,000 in addition gross margin generated from 14 large commercial and industrial customers added since the second half of 2010, generated $584,000 of this increase. These 14 new large commercial and industrial customers are expected to generate annual gross margin of $1.1 million in 2011. The same customers generated $196,000 of gross margin following their addition in the second half of 2010. Two-percent growth in residential customers generated an additional $271,000 in gross margin for the Delmarva natural gas distribution operation.

- The remaining increase in gross margin of $11,000 was attributable to higher customer consumption, offset partially by a decrease from a change in customer rates and rate classes.

Gross margin for our Florida natural gas distribution operation decreased by $977,000 during the first six months of 2011 compared to the same quarter in 2010. The factors contributing to this decrease were as follows:

- Lower customer consumption during the first six months of 2011, compared to the same period in 2010, due primarily to significantly warmer weather during the heating season, decreased gross margin by $1.9 million. Heating degree-days in Florida decreased by 43 percent, or 408 heating degree-days, during the first six months of 2011, compared to the same period in 2010.

- One-percent customer growth in residential customers and three-percent growth in commercial customers for the Florida natural gas distribution operation generated additional gross margin of $576,000 in the first half of 2011, compared to the same period in 2010.

- 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company in August 2010, generated $325,000 in new gross margin in the first six months of 2011.

Our natural gas transmission operations achieved gross margin growth of $1.4 million during the first six months of 2011 compared to the same period in 2010. The factors contributing to this increase were as follows:

- New transportation services associated with Eastern Shore's eight-mile mainline extension to interconnect with TETLP's pipeline system generated an additional $1.1 million of gross margin in the six months ended June 30, 2011. These new services commenced in January 2011 and have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, and an estimated annual gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million annually thereafter.

- New transportation services implemented by Eastern Shore in May 2010 and November 2010 as a result of its system expansion projects generated an additional $247,000 of gross margin during the first half of 2011, compared to 2010. These expansions added 2,666 Mcfs of capacity per day and an estimated annual gross margin of $574,000 in 2011. These projects generated $216,000 of gross margin in 2010, $40,000 of which was recorded in the first half of 2010.

- Eastern Shore entered into two additional transportation services agreements with an existing industrial customer, one for the period of May 2011 through April 2021 for an additional 3,290 Mcfs per day and the other one for the period of November 2011 through October 2012 for an additional 9,192 Mcfs per day. These services generated additional gross margin of $61,000 in the first half of 2011 and are expected to generate additional gross margin of $356,000 in 2011, $1.2 million in 2012 and $369,000 annually thereafter.

- The foregoing increases to gross margin were offset by the expiration of two small firm transportation service contracts in April 2010, decreasing gross margin by $40,000 in the second half of 2011.

Gross margin for our Florida electric distribution operation decreased by $319,000 in the first six months of 2011, compared to the same period in 2010, due primarily to lower customer consumption during the heating season. Heating degree-days in Florida decreased by 43 percent, or 408 heating degree-days during the first six months of 2011, compared to the same period in 2010.

Other Operating Expenses
Other operating expenses for the regulated energy segment increased by $2.6 million in the six months ended June 30, 2011, due largely to the following factors:

- One-time charges totaling $651,000 associated with the voluntary workforce reduction in Florida and a pension settlement;
- Increased regulatory, legal and other costs, including $316,000 of additional costs associated with the electric franchise dispute in Marianna Florida and $137,000 in costs with respect to the "Come-Back" filing in Florida and the rate case proceeding for Eastern Shore;
- $559,000 in higher depreciation expense and asset removal costs from capital investments made since the second half of 2010;
- $416,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements; and
- $147,000 of other operating expenses during the first half of 2011 associated with the purchase of the operating assets of Indiantown Gas Company in August 2010.

Other Development
In June 2011, Allen Family Foods, Inc. and related entities (collectively, "Allen") filed for bankruptcy. Our Delmarva natural gas distribution operation serves two of Allen's poultry facilities, one of which is included in our discussion of 14 new large commercial and industrial customers added since July 2010. Gross margin generated from our natural gas service to these two Allen facilities was approximately $94,000 and $24,000 for the three months ended June 30, 2011 and 2010, respectively, and approximately $211,000 and $51,000 for the first six months of 2011 and 2010, respectively. The total gross margin for 2010 from our natural gas service to these two facilities was approximately $156,000. As of June 30, 2011, we had approximately $40,000 in outstanding receivable balances with Allen. Since the bankruptcy filing, these two facilities have been sold to another poultry processor. We cannot predict the future plan for these two facilities by the new purchaser or the level of natural gas consumption, if any, at these two facilities in the future.

Unregulated Energy

For the Six Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands, except degree-day data)			
Revenue	**$88,442**	$83,885	$4,557
Cost of sales	**65,604**	63,027	2,577
Gross margin	**22,838**	20,858	1,980
Operations & maintenance	**11,924**	11,356	568
Depreciation & amortization	**1,562**	1,765	(203)
Other taxes	**834**	768	66
Other operating expenses	**14,320**	13,889	431
Operating Income	**$8,518**	$6,969	$1,549

Weather Analysis — Delmarva Peninsula			
Actual HDD	**2,827**	2,971	(144)
10-year average HDD	**2,863**	2,831	32

Operating income for the unregulated energy segment increased by approximately $1.5 million, or 22 percent, during the first six months of 2011, compared to the same period in 2010, primarily due to a gross margin increase of $2.0 million, partially offset by an operating expenses decrease of $431,000.

Gross Margin

Gross margin for our unregulated energy segment increased by $2.0 million, or nine percent, for the first six months of 2011, compared to the same period in 2010.

Our Delmarva propane distribution operation experienced an increase in gross margin of $1.4 million for the first six months of 2011, compared to the same period in 2010. The factors contributing to this increase were as follows:

- Our Delmarva propane distribution operation generated additional gross margin of $980,000 due to higher margins per gallon during the first six months of 2011, compared to the same quarter in 2010, as margins per gallon returned to more normal levels during the current period. Propane margins per gallon during the first half of 2010 were low, compared to historical levels, due to additional spot purchases at increased costs during the peak heating season to meet the weather-related increase in customer consumption. More normal temperatures and fewer spot purchases during 2011 resulted in margins per gallon in the first six months of 2011 returning to more normal levels.

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

- An increase in other fees generated additional gross margin of $152,000, due primarily to the continued growth and successful implementation of various customer pricing programs.

- A decline in volumes sold in the first half of 2011, compared to the same period in 2010, decreased gross margin by $279,000. This decrease was attributable to timing of deliveries to bulk customers and a decrease in weather-related consumption due to the warmer temperatures on the Delmarva Peninsula.

Our Florida propane distribution operations experienced an increase in gross margin of $75,000 during the first half of 2011 compared to the same period in 2010. Higher margins per gallon, as we continued to adjust our retail pricing in response to market conditions, were offset by a decrease in volume sold during the period.

Xeron, the Company's propane wholesale marketing subsidiary, generated $412,000 of increase in gross margin during the first six months of 2011, compared to the same period in 2010, due primarily to an increase in Xeron's trading activity by 50 percent in the first six months of 2011, compared to the same period in 2010.

Gross margin generated by PESCO, our natural gas marketing subsidiary, increased by $301,000 during the first six months of 2011, compared to the same period in 2010. This increase was due to favorable imbalance resolutions during the first half of 2011 with third-party intrastate pipelines, with which PESCO contracts for supply. Revenues generated from favorable imbalance resolutions with intrastate pipelines are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Merchandise sales in Florida decreased in the first six months of 2011, compared to the same period in 2010, resulting in lower gross margin of $174,000.

Other Operating Expenses
Other operating expenses for the unregulated energy segment increased by $430,000 for the first half of 2011, compared to the same period in 2010, due primarily to the following factors: (a) increased payroll and benefit costs of $347,000, attributable primarily to higher accruals for performance incentive compensation; (b) increased vehicle expenses of $ $202,000 resulting from an increase in fuel prices; and (c) one-time charges of $67,000 for the unregulated energy businesses associated with the voluntary workforce reduction in Florida.

Other

For the Six Months Ended June 30,	2011	2010	Increase (decrease)
(in thousands)			
Revenue	**$5,658**	$5,069	$589
Cost of sales	**3,107**	2,448	659
Gross margin	**2,551**	2,621	(70)
Operations & maintenance	**2,046**	1,768	278
Depreciation & amortization	**209**	145	64
Other taxes	**370**	342	28
Other operating expenses	**2,625**	2,255	370
Operating Income - Other	**(74)**	366	(440)
Operating Income - Eliminations	**-**	-	-
Operating Income	**($74)**	$366	($440)

Note: Eliminations are entries required to eliminate activities between business segments from the consolidated results.

Operating income for the "other" segment decreased by approximately $440,000 during the first six months of 2011, compared to the same period in 2010, which was attributable to a gross margin decrease of $70,000 and an operating expense increase of $370,000.

Gross margin
The gross margin decrease of $70,000 for our "other" segment was primarily a result of lower consulting margin and additional costs associated with initial implementation of ProfitZoom™, which were slightly offset by an increase of product sales for BravePoint, our advanced information services subsidiary.

Other Operating expenses
Other operating expenses increased by $370,000 in the first six months of 2011, compared to the same period in 2010. Other operating expenses for BravePoint increased by $498,000, due primarily to $439,000 in additional marketing and development costs, as it began to roll out ProfitZoom™, and $249,000 in increased benefit costs. Benefit costs increased for BravePoint as Chesapeake adopted a safe harbor 401(k) plan design on January 1, 2011, which resulted in an increased 401(k) benefit for BravePoint employees in 2011. The increase in BravePoint's other operating expenses was offset partially by the absence in 2011 of $111,000 in merger-related costs in the first half of 2010.

Interest Expense

Interest expense for the six months ended June 30, 2011 decreased by approximately $403,000, or nine percent, compared to the same period in 2010, due primarily to a decrease of $424,000 in other long-term interest expense as the outstanding principal balance decreased as a result of scheduled repayments.

On June 23, 2011, we issued $29 million of 5.68 percent unsecured senior notes to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement executed in June 2010. We used the proceeds to permanently refinance the redemption of the two series of FPU first mortgage bonds mentioned previously, which were temporarily refinanced using a short-term loan credit facility. Compared to interest expense incurred under the short-term loan credit facility during the first half of 2011, issuance of these senior notes will result in an increase in interest expense of $550,000 in the second half of 2011.

Income Taxes

We recorded an income tax expense of $11.1 million for the first half of 2011, compared to $11.3 million for the same period in 2010. The period-over-period decrease in income tax expense is primarily a function of lower earnings for the period.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

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

Our energy businesses are weather sensitive and seasonal. We normally generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas 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.

Capital expenditures are one of our largest capital requirements. We originally budgeted $51.7 million for capital expenditures during 2011. As a result of continued growth, expansion opportunities and timing of capital projects, we increased our capital spending projection for 2011 to $62.6 million. This amount includes $54.3 million for the regulated energy segment, $2.9 million for the unregulated energy segment and $5.4 million for the "other" segment. The amount for the regulated energy segment includes estimated capital expenditures for expansion and improvement of facilities for the following: (a) natural gas distribution operation ($21.8 million); (b) natural gas transmission operation ($27.3 million); and (c) electric distribution operation ($5.2 million). 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 $377,000 for the advanced information services operation, with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2011 capital expenditures program from short-term borrowing, cash provided by operating activities, and other sources. The capital expenditures program is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of June 30, 2011 and December 31, 2010:

	June 30, 2011		December 31, 2010	
(in thousands)				
Long-term debt, net of current maturities	**$117,123**	**33%**	$89,642	28%
Stockholders' equity	**238,000**	**67%**	226,239	72%
Total capitalization, excluding short-term debt	**$355,123**	**100%**	$315,881	100%

	June 30, 2011		December 31, 2010	
(in thousands)				
Short-term debt	**$4,248**	**1%**	$63,958	16%
Long-term debt, including current maturities	**126,319**	**34%**	98,858	25%
Stockholders' equity	**238,000**	**65%**	226,239	59%
Total capitalization, including short-term debt	**$368,567**	**100%**	$389,055	100%

Short-term Borrowings

Our outstanding short-term borrowings at June 30, 2011 and December 31, 2010 were $4.2 million and $64.0 million, respectively, at weighted average interest rates of 1.54 percent and 1.77 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to fund temporarily portions of the capital expenditure program. As of June 30, 2011, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at June 30, 2011 and December 31, 2010 were $3.4 million and $30.8 million, respectively, at weighted average interest rates of 1.50 percent and 1.65 percent, respectively. In addition to the four unsecured bank lines of credit, we entered into a new short-term credit facility for $29.1 million with an existing lender in March 2010 to temporarily finance the early redemption of the 6.85 percent and 4.90 percent series of FPU's secured first mortgage bonds. On June 23, 2011, we issued $29.0 million of 5.68 percent Chesapeake's unsecured senior notes to repay the new short-term credit facility and permanently finance the FPU first mortgage bonds.

Cash Flows Provided By Operating Activities

Cash flows provided by operating activities were as follows:

For the Six Months Ended June 30,	**2011**	**2010**
(in thousands)		
Net Income	**$17,267**	$17,314
Non-cash adjustments to net income	**25,869**	15,152
Changes in assets and liabilities	**16,953**	24,549
Net cash provided by operating activities	**$60,089**	$57,015

During the six months ended June 30, 2011 and 2010, net cash flow provided by operating activities was $60.1 million and $57.0 million, respectively, a period-over-period increase of $3.1 million. Significant operating activities reflected in the change in cash flows provided by operating activities were as follows:

- Net cash flows related to income taxes, which include deferred income taxes in non-cash adjustments to net income and the change in income taxes receivable, increased by $3.9 million in the first half of 2011, compared to the same period in 2010, due primarily to the 100 percent bonus depreciation deduction allowed in 2011, which is reducing our income tax payments in the current period.

- Net cash flows from trading receivables and payables increased by $3.0 million, due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale marketing operation, offset partially by a decrease in net cash flows from receivables and payables in the natural gas and propane distributions operations.

- Net cash flows from customer deposits decreased by $2.2 million, due primarily to a large deposit received from a new industrial customer during the first half of 2010, which increased the cash flow for that period.

- Net cash flows from accrued compensation decreased by $2.3 million, as a result of a smaller decrease in the change in accrued payroll due to timing of payroll periods and higher incentive compensation payments in the first half of 2011, compared to the same period in 2010.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $21.4 million and $14.3 million during the six months ended June 30, 2011 and 2010, respectively. Cash utilized for capital expenditures was $21.2 million and $13.6 million for the first six months of 2011 and 2010, respectively.

Cash Flows Used by Financing Activities

Cash flows used in financing activities totaled $38.5 million and $36.3 million for the first six months of 2011 and 2010, respectively. Significant financing activities reflected in the change in cash flows used by financing activities were as follows:

- During the first six months of 2011 we had a net repayment of $27.4 million under our line of credit agreements related to working capital, compared to $29.2 million in the same period in 2010, resulting in a period-over-period net cash increase of $1.8 million. Changes in cash overdrafts increased by $2.4 million, resulting in a period-over-period net cash decrease.

- Net repayments of other short-term debt and long-term debt during the first six months of 2011 were $1.6 million, compared to net repayments of $1.2 million in the same period in 2010. During the first six months of 2010, we redeemed the 6.85 and 4.90 series of FPU's secured first mortgage bonds prior to their respective maturities by using the proceeds from a new short-term credit facility. During the first six months of 2011, we issued Chesapeake's unsecured senior notes, using the proceeds to repay the new short-term credit facility and permanently finance the FPU bonds.

- We paid $5.7 million and $5.4 million in cash dividends for the six months ended June 30, 2011 and 2010, respectively.

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 our financial statements when incurred. The aggregate amount guaranteed at June 30, 2011 was $25.6 million, with the guarantees expiring on various dates through 2012.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $441,000, which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. Although we recently changed our primary insurance company, we still have an outstanding letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2012. There have been no draws on these letters of credit as of June 30, 2011. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.5 million under the Precedent Agreement with TETLP, which is the maximum amount required under the agreement.

Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2010 Annual Report on Form 10-K, except for commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes the commodity and forward contract obligations at June 30, 2011.

	Payments Due by Period				
Purchase Obligations	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
(in thousands)					
Commodities [1]	$ 13,892	$ -	$ -	$ -	$ 13,892
Propane [2]	24,406	-	-	-	24,406
Total Purchase Obligations	**$ 38,298**	**$ -**	**$ -**	**$ -**	**$ 38,298**

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

(2) We have also entered into forward sale contracts in the aggregate amount of $13.9 million. See Part I, Item 3, "Quantitative and Qualitative Disclosures about Market Risk," below, for further information.

Environmental Matters

As more fully described in Note 4, "Environmental Commitments and Contingencies," to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites. We believe that future costs associated with these sites will be recoverable in rates or through sharing arrangements with, or contributions by, other responsible parties.

OTHER MATTERS

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by their respective PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At June 30, 2011, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rate filings and/or regulatory matters is fully described in Note 3, "Rates and Other Regulatory Activities," to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Competition

Our natural gas and electric distribution operations and our natural gas transmission 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 because the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

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

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

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

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

Inflation

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

To compensate for fluctuations in propane gas prices, we adjust propane selling prices to the extent allowed by the market.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments applicable to us and their impact on our financial position, results of operations and cash flows are described in Note 1, "Summary of Accounting Policies," to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was $126.3 million at June 30, 2011, as compared to a fair value of $145.0 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 six million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are 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 June 30, 2011 is presented in the following tables.

At June 30, 2011	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	9,240,000	\$1.3900 — \$1.5700	\$1.5005
Purchase	8,106,000	\$1.3344 — \$1.5850	\$1.4878

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire during or prior to the first quarter of 2012.

At June 30, 2011 and December 31, 2010, we marked these forward contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	June 30, 2011	December 31, 2010
Mark-to-market energy assets	**\$335**	\$1,642
Mark-to-market energy liabilities	**\$216**	\$1,492

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of June 30, 2011. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2011.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2011, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 5, "Other Commitments and Contingencies," of the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we are involved in certain legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental or regulatory agencies concerning rates and other regulatory actions. In the opinion of management, the ultimate disposition of these proceedings and claims will not have a material effect on our condensed consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2010, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating the Company, our business and the forward-looking statements contained in this Report. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may affect the Company. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
April 1, 2011 through April 30, 2011 [1]	231	$42.62	-	-
May 1, 2011 through May 31, 2011	-	$ -	-	-
June 1, 2011 through June 30, 2011	-	$ -	-	-
Total	231	$42.62	-	-

[1] Chesapeake purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements - Note M, Employee Benefit Plans" of our Form 10-K filed with the Securities and Exchange Commission on March 8, 2011. During the quarter, 231 shares were purchased through the reinvestment of dividends on deferred stock units.

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

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

Item 6. Exhibits

31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated August 5, 2011.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated August 5, 2011.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated August 5, 2011.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated August 5, 2011.

SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer

Date: August 5, 2011

EXHIBIT 31.1

**CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934**

I, Michael P. McMasters, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2011 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2011

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934

I, Beth W. Cooper, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended June 30, 2011 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2011

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

Certificate of Chief Executive Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Michael P. McMasters, President and Chief Executive Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended June 30, 2011, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters
August 5, 2011

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

Certificate of Chief Financial Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Beth W. Cooper, Senior Vice President and Chief Financial Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended June 30, 2011, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ BETH W. COOPER
Beth W. Cooper
August 5, 2011

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit B

CHESAPEAKE UTILITIES CORPORATION
RETIREMENT SAVINGS PLAN AND TRUST

Amended and Restated Effective as of January 1, 2011

12/2010

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CHESAPEAKE UTILITIES CORPORATION

RETIREMENT SAVINGS PLAN

INTRODUCTION

Chesapeake Utilities Corporation, a Delaware corporation, hereby amends and restates in its entirety the Chesapeake Utilities Corporation Retirement Savings Plan, generally effective as of January 1, 2011, unless otherwise stated herein. Previously, the Plan, originally adopted effective as of February 1, 1977, was restated most recently as of January 1, 2006. Special effective dates are included with respect to a number of provisions as necessary to conform to amendments to the Internal Revenue Code of 1986, as amended (the "Code") and the Treasury Regulations promulgated thereunder as enacted by the Pension Protection Act of 2006 ("PPA") as amended by the Worker, Retiree and Employer Recovery Act of 2008 ("WRERA") and the Heroes Earnings Assistance and Relief Tax Act of 2008 (the "HEART Act"), in addition to legislation and regulatory changes in tax qualification requirements, including the final Treasury Regulations under Code Section 415, among other requirements. In addition, special effective dates are included in the Plan to implement various design changes.

The Employer intends that the Plan be qualified under Code Section 401(a) with a cash or deferred arrangement qualified under Code Section 401(k) and a trust exempt from taxation under Code Section 501(a). Pursuant to the requirements of Code Section 401(a)(27), the Employer intends that the Plan be a profit sharing plan. The Plan also contains an employee stock ownership plan component pursuant to the requirements of Code Section 4975(e)(7).

The purpose of this Plan is to encourage eligible employees to accumulate savings for retirement and to further their financial independence by affording them an opportunity to make systematic contributions to the Plan, supplemented by contributions made by the Employer. In addition, effective January 1, 2011, the Plan is intended to be a qualified automatic contribution arrangement ("QACA") and to meet the safe harbor requirements under Code Section 401(k). All provisions herein shall be interpreted and administered in compliance with the applicable Code Sections.

The provisions of this amended and restated Plan shall apply solely to an Employee whose employment with the Employer terminates on or after the Effective Date. An Employee whose employment with the Employer terminates prior to the Effective Date shall be entitled to a benefit, if any, as determined under the provisions of the Plan in effect on the date his employment terminated.

ARTICLE I
DEFINITIONS

Each word and phrase defined in this Article I shall have the following meaning whenever such word or phrase is capitalized and used herein unless a different meaning is clearly required by the context of this agreement.

Section 1.01 Account. The separate bookkeeping account that the Committee or the Trustee shall maintain for a Participant pursuant to Section 9.13 of the Plan.

Section 1.02 Accounting Date. The last day of the Plan Year.

Section 1.03 Before-Tax Account. The portion of a Participant's Account credited with Before-Tax Contributions under Section 3.02A. of the Plan, and adjustments relating thereto.

Section 1.04 Beneficiary. A person, including any individual, legal representative, estate or other entity, designated by a Participant who is or may become entitled to a benefit under the Plan. A Beneficiary who becomes entitled to a benefit under the Plan shall remain a Beneficiary under the Plan until the Trustee has fully distributed his benefit to him. A Beneficiary's right to (and the Plan Administrator's, the Committee's, or a Trustee's duty to provide to the Beneficiary) information or data concerning the Plan shall not arise until he first becomes entitled to receive a benefit under the Plan.

Section 1.05 Board. The board of directors of Chesapeake Utilities Corporation or a committee thereof acting on its behalf.

Section 1.06 Catch-Up Account. The portion of a Participant's Account credited with Catch-Up Contributions under Section 3.02B., and adjustments relating thereto.

Section 1.07 Code. The Internal Revenue Code of 1986, as amended or as it may be amended from time to time. Reference to any section of the Code includes (a) any regulations and rulings applying to that section and (b) comparable provisions of future laws.

Section 1.08 Committee. The Employee Benefits Committee or such other person or persons appointed pursuant to Article IX of the Plan, as from time to time constituted, to assist the Employer in the administration of the Plan in accordance with said Article.

Section 1.09 Company. Chesapeake Utilities Corporation, a Delaware corporation.

Section 1.10 Compensation.

A. Definition. The Participant's wages, salaries, fees for professional services and other amounts received for personal services actually rendered in the course of employment with an Employer maintaining the Plan (including but not limited to commissions paid salespersons, compensation for services on the basis of a percentage of profits, commissions on insurance premiums, tips and bonuses). Compensation also includes "Elective Contributions" made by the Employer on the Employee's behalf. Elective Contributions are amounts excludible from the Employee's gross income under

Code Section 402(e)(3) (relating to a Code Section 401(k) arrangement), Code Section 402(h) (relating to a Simplified Employee Pension), Code Section 125 (relating to a cafeteria plan), Code Section 403(b) (relating to a tax-sheltered annuity), Code Section 132(f)(4) (relating to a qualified transportation fringe benefit plan), Code Section 408(p) (relating to a Simple Retirement Account), Code Section 457 (relating to government and tax-exempt organizations) and "deemed compensation" under Code Section 125 pursuant to Revenue Ruling 2002-27. Effective January 1, 2009, Compensation shall also include any differential wage payments (as defined in Code Section 3401(h)(2)) made by the Employer, as required by Code Section 414(u)(12), as amended by the HEART Act. The term "Compensation" does not include:

(i) Contributions (other than Elective Contributions) to a plan of deferred compensation to the extent the contributions are not included in the gross income of the Employee for the taxable year in which contributed, on behalf of an Employee to a Simplified Employee Pension Plan to the extent such contributions are excludible from the Employee's gross income, and any distributions from a plan of deferred compensation, regardless of whether such amounts are includible in the gross income of the Employee when distributed.

(ii) Amounts realized from the exercise of a non-qualified stock option, or when restricted stock (or property) held by an Employee either becomes freely transferable or is no longer subject to a substantial risk of forfeiture, or when such an amount is includable in gross income due to a Code Section 83(b) election.

(iii) Amounts realized from the sale, exchange or other disposition of stock acquired under a qualified stock option (as defined in Treasury Regulations Section 1.421-1(b)).

(iv) Other amounts that receive special tax benefits, such as premiums for group-term life insurance (whether or not the premiums are includable in the gross income of the Employee or are salary reduction amounts that are described in Code Section 125), other than Elective Contributions.

(v) Moving expenses or allowances, automobile allowances, cash allowances in exchange for opting out of certain welfare plan coverage, tuition reimbursement, other reimbursements or expense allowances, fringe benefits, and any other taxable welfare benefits, such as certain payments under an accident or health plan.

(vi) Severance pay or any other amounts paid after the Participant has incurred a Severance from Employment except to the extent such amounts meet the definition of Post-Severance Compensation under Section I.07(C).

Any reference in this Plan to Compensation is a reference to the definition in this Section 1.10, unless the Plan reference specifies a modification to this definition. The Committee will take into account only Compensation actually paid during the portion of the Plan Year in which the Employee is a Participant in the Plan.

B. Compensation Limit. In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provisions of the Plan to the contrary, the annual Compensation of each Employee taken into account under the Plan shall not exceed the Compensation Limitation under Code Section 401(a)(17) in effect for the applicable Determination Period as defined herein. Effective January 1, 2011, the "Compensation Limitation" is $245,000, and is subject to cost of living adjustments in future years in accordance with Code Section 401(a)(17)(B) and applicable statutory changes. Any such cost of living adjustment or statutory change in effect for a calendar year applies to any period, not exceeding 12 months, over which Compensation is determined (the "Determination Period") beginning in such calendar year. If a Determination Period consists of fewer than 12 months, the Compensation Limitation will be multiplied by a fraction, the numerator of which is the number of months in the Determination Period, and the denominator of which is 12. Any reference in this Plan to the limitation under Section 401(a)(17) of the Code shall mean the Compensation Limitation set forth in this provision.

C. Compensation – Special Rules. For purposes of determining whether the Plan discriminates in favor of Highly Compensated Employees, the Employer may elect to use an alternate nondiscriminatory definition of Compensation, in accordance with the requirements of Code Section 414(s) and the Treasury Regulations promulgated thereunder. In determining Compensation (for purposes of determining whether the Plan discriminates in favor of Highly Compensated Employees), the Employer may elect to include as Compensation all Elective Contributions made by the Employer on behalf of Employees. The Employer's election to include Elective Contributions must be consistent and uniform with respect to Employees and all plans of the Employer for any particular Plan Year. The Employer may make this election to include Elective Contributions for nondiscrimination testing purposes, irrespective of whether subsection A. above includes Elective Contributions in the general definition of Compensation applicable to the Plan.

Section 1.11 Disability or Disabled. An illness or injury of a potentially permanent nature, expected to last for a continuous period of not less than 12 months, certified by a physician selected by or satisfactory to the Employer, which prevents the Employee from engaging in any occupation for wage or profit for which the Employee is reasonably fit by training, education or experience. Any Disability must arise while the Participant is employed by an Employer to qualify under this provision.

Section 1.12 Early Retirement Age. The attainment of age 55.

Section 1.13 Effective Date. January 1, 2011, the date on which the provisions of this amended and restated Plan become effective, except as otherwise provided herein.

Section 1.14 Eligible Employee. Any Employee other than (a) an Employee who may be excluded from participation pursuant to Code Section 410(b)(3) as a nonresident alien, or (b) as an Employee covered by a collective bargaining agreement recognized as such under applicable federal labor law and which does not expressly provide for participation in the Plan by Employees covered thereunder. In addition, a part-time, seasonal or temporary employee is not an Eligible Employee if he or she fails to complete a Year of Service in a 12 month computation period commencing with his or her Employment Commencement Date (or an anniversary of such date).

Section 1.15 Employee. Any person who, on or after the Effective Date, is receiving remuneration for personal services rendered to the Employer (or any other employer required to be aggregated with the Employer under Code Sections 414(b), (c), (m) or (o)) as a common law employee (or who would be receiving such remuneration except for an authorized leave of absence). The term shall not include any individual providing services to an Employer as a consultant, independent contractor or Leased Employee deemed to be an employee of any employer described in the previous sentence, as provided in Code Sections 414(n) and (o), nor any person employed by the Employer solely as a director. An individual excluded from participation by reason of independent contractor or Leased Employee status, if determined by the Company or in accordance with law to be a common law employee, shall be recharacterized as an Employee under the Plan as of the date of such determination, unless an earlier date is necessary to preserve the tax qualified status of the Plan. Notwithstanding such general recharacterization, such person shall not be considered an Eligible Employee for purposes of Plan participation, except and to the extent necessary to preserve the tax qualified status of the Plan.

Effective January 1, 2009, an Employee also includes any individual in Qualified Military Service (as defined in Code Section 414(u)) who is receiving differential wage payments (as defined in Code Section 3401(h)(2)) from the Employer solely for the purposes of providing contributions, benefits and Service credit with respect to Qualified Military Service, as applicable.

Section 1.16 Employee Contractor. An Employee hired for a specific job or jobs to be supervised directly or indirectly by the Employer. Hours worked and duration of employment are at the discretion of the Employer. The Employee Contractor will work on an "as needed" basis and is not eligible for any employee benefits offered by the Employer unless specified at the time of employment. The status of an Employee Contractor is subject to change at the discretion of the Employer. No Employee Contractor shall be considered to be an Employee; however, for purposes of administering and construing this Plan, any reference to Employee will also mean an Employee Contractor, with the exception of any references to Employer Matching, Supplemental, Qualified Non-Elective, and Qualified Matching Contributions being made on any Employee's behalf.

Section 1.17 Employer(s). The Company and any Related Employer that is listed on the attached Schedule II. The effective date of a Related Employer's participation in the Plan shall also be listed on the attached Schedule II if different from the date such entity became a Related Employer. Whenever the terms of this Plan authorize the Employer or the Company to take any action, such action shall be considered properly authorized if taken by the Board, any committee of the Board, or by the Committee for the Plan in accordance with its procedures under Section 9.03 of the Plan.

Section 1.18 Employer Securities. Shares of common stock of Chesapeake Utilities Corporation, which shall be an "employer security" within the meaning of Code Section 409(l).

Section 1.19 ERISA. The Employee Retirement Income Security Act of 1974, as the same may be amended from time to time.

Section 1.20 Former Participant. A Participant who has transferred to a classification of Employees ineligible to participate in the Plan, or a Participant whose employment with the Employer has terminated but who has a vested Account balance under the Plan that has not been paid in full and, therefore, is continuing to participate in the allocation of Trust Income.

Section 1.21 Highly Compensated Employee. Any Employee who:

A. at any time during the current Plan Year or the preceding Plan Year was a Five-percent Owner of the Employer as defined in Code Section 416(i); or

B. for the preceding Plan Year received more than $110,000 in annual Compensation from the Employer (or such higher amount as adjusted pursuant to Code Section 414(q)(1)).

Highly Compensated Employees include highly compensated former Employees. A former Employee will be treated as a Highly Compensated Employee if such Employee incurred a Severance from Employment (or was deemed to have separated) prior to the current or preceding Plan Year, performs no Service during such Plan Year, and was a Highly Compensated Employee for either the separation year or any Plan Year ending on or after the Employee's 55th birthday, in accordance with the rules for determining Highly Compensated Employee status in effect for that determination year and in accordance with applicable Treasury Regulations and Internal Revenue Service ("IRS") Notice 97-45.

For purposes of this Section, "Compensation" means Compensation as defined in Section 1.10 of the Plan; and Related Employers to the Company shall be treated as a single employer with the Company. The determination of who is Highly Compensated shall be made in accordance with Code Section 414(q) and applicable Treasury Regulations promulgated thereunder.

Section 1.22 Income. The net gain or loss of the Trust from investments, as reflected by interest payments, dividends, realized and unrealized gains and losses on securities, other investment transactions and expenses paid from the Trust. In determining the Income of the Trust as of any date, assets shall be valued on the basis of their then fair market value.

Section 1.23 Investment Manager. A person or organization who is appointed under Section 9.05 of the Plan to direct the investment of all or part of the Trust, and who is either (a) registered in good standing as an Investment Adviser under the Investment Advisers Act of 1940, (b) a bank, as defined in that Act, or (c) an insurance company qualified to perform investment management services under the laws of more than one state of the United States, and who has acknowledged in writing that he is a fiduciary with respect to the Plan.

Section 1.24 Leased Employee. Any person (other than an Employee of the Employer) who, pursuant to an agreement between the Employer and any other person ("Leasing Organization"), has performed services for the Employer (or for the Employer and related persons determined in accordance with Code Section 414(n)(6)) on a substantially full-time basis for a period of at least one year, which services are performed under the primary direction or control of the Employer. Contributions or benefits provided to a Leased Employee by the Leasing Organization that are attributable to services performed for the Employer shall be treated as provided by the Employer. If applicable, Compensation under Section 1.10 of the Plan includes compensation from the Leasing Organization which is attributable to services performed for the Employer.

A Leased Employee shall not be considered an Employee of the Employer if (a) such individual is covered by a money purchase pension plan providing: (i) a nonintegrated employer contribution rate of at least 10% of compensation, as defined in Code Section 415(c)(3), but including amounts contributed pursuant to a salary reduction agreement that are excludible from the employee's gross income under Code Sections 125, 132(f)(4), 402(e)(3), 402(h) or 403(b), (ii) immediate participation, and (iii) full and immediate vesting; and (b) Leased Employees do not constitute more than 20% of the Employer's non-highly compensated workforce.

Section 1.25 Matching Account. The portion of a Participant's Account credited with Matching Contributions pursuant to Sections 3.04 and 3.05 of the Plan, and adjustments relating thereto.

Section 1.26 Nonforfeitable. A Participant's or Beneficiary's unconditional claim, legally enforceable against the Plan, to all or a portion of the Participant's Account.

Section 1.27 Nonforfeitable Account Balance. The aggregate value of the Participant's vested Account balances derived from Employer and Employee contributions (including Transfer and Rollover Contributions), whether vested before or upon death.

Section 1.28 Non-Highly Compensated Employee. Any Eligible Employee who is not a Highly Compensated Employee.

Section 1.29 Normal Retirement Age. The attainment of age 65. "Normal Retirement" means a Participant's Severance from Employment following his attainment of Normal Retirement Age.

Section 1.30 Participant. An Employee who is eligible to be and becomes a Participant in accordance with the provisions of Article II of the Plan. An Employee who becomes a Participant shall remain a Participant or Former Participant under the Plan until the Trustee has fully distributed the vested amount in his Account to him. For purposes of administering and construing this Plan, any reference to a Participant also means a Participating Employee Contractor, with the exception of any references to Employer Matching, Supplemental, Qualified Non-Elective and Qualified Matching Contributions being made on any Participant's behalf.

Section 1.31 Plan. The plan designated as the Chesapeake Utilities Corporation Retirement Savings Plan as set forth herein or in any amendments hereto.

Section 1.32 Plan Administrator. Chesapeake Utilities Corporation or the person(s) or entity appointed by Chesapeake Utilities Corporation to serve as Plan Administrator.

Section 1.33 Plan Year. The calendar year commencing on January 1 and ending on December 31.

Section 1.34 Qualified Matching Contribution Account. The portion of a Participant's Account credited with Qualified Matching Contributions under Section 3.04 of the Plan, and adjustments relating thereto.

Section 1.35 Qualified Non-Elective Contribution Account. The portion of a Participant's Account credited with Qualified Non-Elective Contributions under Section 3.07 of the Plan, and adjustments relating thereto.

Section 1.36 Related Employers. A controlled group of corporations (as defined in Code Section 414(b)), trades or business (whether or not incorporated) which are under common control (as defined in Code Section 414(c)), or an affiliated service group (as defined in Code Sections 414(m) and (o)). If the Employer is a member of a group of Related Employers, the term "Employer" includes the Related Employers for purposes of crediting Hours of Service, applying the coverage test of Code Section 410(b), determining Years of Service and Breaks in Service under Article IV of the Plan, applying the limitations described in Schedule I, applying the Top Heavy rules and the minimum benefit requirements of Article X of the Plan, the definitions of Employee, Highly Compensated Employee, Compensation, Leased Employee, and Service contained in this Article I, and for any other purpose as required by the Code or by the Plan. However, only an Employer described in Section 1.17 of the Plan may contribute to the Plan, and only an Employee employed by an Employer described in Section 1.17 is eligible to participate in this Plan.

Section 1.37 Required Beginning Date. For purposes of Article V of the Plan, for any Participant who is not a Five-percent Owner (as defined in Code Section 416(i)), the Required Beginning Date is the April 1 of the calendar year following the later of the calendar year in which the Participant attains age 70½, or the calendar year in which the Participant retires. For any Participant who is at least a Five-percent Owner (as defined in Code Section 416(i)), the Required Beginning Date is the April 1 immediately following the calendar year in which the Participant attains age 70½, regardless of whether the Participant has retired.

Section 1.38 Rollover Account. The portion of a Participant's Account credited with Rollover Contributions under Section 3.12 of the Plan, and adjustments relating thereto.

Section 1.39 Service and Break in Service Definitions.

A. Absence from Service. A severance or absence from service for any reason other than a quit, discharge, retirement or death, such as vacation, holiday, sickness, or layoff. Notwithstanding the foregoing, an absence due to an Authorized Leave of Absence or qualified military service in accordance with Code Section 414(u) shall not constitute an Absence from Service.

B. Authorized Leave of Absence. Authorized Leave of Absence means:

(i) a leave of absence, with or without pay, granted by the Employer in writing under a uniform, nondiscriminatory policy applicable to all Employees;

however, such absence shall constitute an Authorized Leave of Absence only to the extent that applicable federal laws and regulations permit service credit to be given for such leave of absence;

(ii) a leave of absence due to service in the Armed Forces of the United States to the extent required by Code Section 414(u); or

(iii) a leave of absence authorized under the Family and Medical Leave Act, but only to the extent that such Act requires that service credit be given for such period.

C. Break in Service. Each Plan Year during which an Employee fails to complete more than 500 Hours of Service.

D. Employment Commencement Date. The date upon which an Employee first performs an Hour of Service for the Employer.

E. Hour of Service. Hour of Service means:

(i) Each Hour of Service for which the Employer, either directly or indirectly, pays an Employee, or for which the Employee is entitled to payment, for the performance of duties during the Plan Year. The Committee shall credit Hours of Service under this subparagraph (i) to the Employee for the Plan Year in which the Employee performs the duties, irrespective of when paid;

(ii) Each Hour of Service for back pay, irrespective of mitigation of damages, to which the Employer has agreed or for which the Employee has received an award. The Committee shall credit Hours of Service under this subparagraph (ii) to the Employee for the Plan Year(s) to which the award or the agreement pertains rather than for the Plan Year in which the award, agreement or payment is made; and

(iii) Each Hour of Service for which the Employer, either directly or indirectly, pays an Employee, or for which the Employee is entitled to payment (irrespective of whether the employment relationship is terminated), for reasons other than for the performance of duties during a Plan Year, such as leave of absence, vacation, holiday, sick leave, illness, incapacity (including disability), layoff, jury duty or military duty. The Committee shall not credit more than 501 Hours of Service under this subparagraph (iii) to an Employee on account of any single continuous period during which the Employee does not perform any duties (whether or not such period occurs during a single Plan Year). The Committee shall credit Hours of Service under this subparagraph (iii) in accordance with the rules of paragraphs (b) and (c) of Labor Reg. Section 2530.200b-2, which the Plan by this reference specifically incorporates in full within this subparagraph (iii).

The Committee shall not credit an Hour of Service under more than one of the subparagraphs above. Furthermore, if the Committee is to credit Hours of Service to an Employee for the 12-month period beginning with the Employee's Employment

Commencement Date or with an anniversary of such date, then the 12-month period shall be substituted for the term "Plan Year" wherever the latter term appears in this Section. The Committee shall resolve any ambiguity with respect to the crediting of an Hour of Service in favor of the Employee.

The Committee shall credit Employees with Hours of Service on the basis of the "actual" method. For purposes of the Plan, the "actual" method means the determination of Hours of Service from records of hours worked and hours for which the Employer makes payment or for which payment is due from the Employer.

Hours of Service will be credited for employment with other members of an affiliated service group (under Code Section 414(m)), a controlled group of corporations (under Code Section 414(b)), or a group of trades or businesses under common control (under Code Section 414(c)) of which the adopting Employer is a member, and any other entity required to be aggregated with the Employer pursuant to Code Section 414(o) and the regulations thereunder. Hours of Service will also be credited for any individual considered an Employee for purposes of this Plan under Code Sections 414(n) or 414(o) and the regulations thereunder.

Solely for purposes of determining whether an Employee whose Service is determined under the Hours of Service method incurs a Break in Service under any provision of this Plan, the Committee shall credit Hours of Service during an Employee's unpaid absence period due to maternity or paternity leave. The Committee shall consider an Employee on maternity or paternity leave if (a) the Employee's absence is due to the Employee's pregnancy, (b) the birth of the Employee's child, (c) the placement with the Employee of an adopted child, or (d) the care of the Employee's child immediately following the child's birth or placement. The Committee shall credit Hours of Service that the Employee would receive if he were paid during the maternity or paternity leave of absence period, or if the Committee cannot determine the number of Hours of Service the Employee would receive, on the basis of eight hours per pay during the absence period. The Committee shall credit only the number of Hours of Service (up to 501 Hours of Service) necessary to prevent a Break in Service. The Committee shall credit all Hours of Service described in this paragraph to the computation period in which the absence period begins or, if the Employee does not need these Hours of Service to prevent a Break in Service in the computation period in which his absence period begins, the Committee shall credit these Hours of Service to the immediately following computation period.

F. Period of Severance. The period commencing on any Severance from Service Date and ending on the date an Employee is again credited with an Hour of Service for the performance of duties for the Employer.

G. Re-employment Commencement Date. The date upon which an Employee first performs an Hour of Service for the Employer following a Break in Service.

H. Severance from Employment. A separation from Service with the Employer maintaining this Plan and any Related Employers such that the Employee no longer has an employment relationship with the Employer or any Related Employers that maintain the Plan.

I. Service. Any period of time the Employee is in the employ of the Employer, determined in accordance with reasonable and uniform standards and policies adopted by the Plan Administrator, which standards and policies shall be consistently observed. For purposes of counting an Employee's Service, the Plan shall treat an Employee's Service with employers who are part of a group of Related Employers of which the Employer is a member as Service with the Employer for the period during which the employers are Related Employers. Service for purposes of determining eligibility to participate and vesting may also, in the Company's discretion, be granted for an Employee's period of Service prior to the date his employer became a Related Employer if such Service is granted in accordance with the requirements of Code Section 401(a)(4) and the Treasury Regulations thereunder. For all Plan purposes, the Plan shall treat the following periods as Service:

(i) any Authorized Leave of Absence, subject to the service crediting limitations set forth in Section 1.39B;

(ii) any qualified military service in accordance with Code Section 414(u);

(iii) any other absence during which the Participant continues to receive his regular Compensation; and

(iv) effective January 1, 2009, as required by Code Section 414(u), as amended by the HEART Act, any individual in Qualified Military Service (as defined in Code Section 414(u)) who is receiving differential wage payments (as defined in Code Section 3401(h)(2)) from the Employer shall be treated as an "Employee" of the Employer solely for the purposes of providing contributions, benefits and Service credit with respect to such Qualified Military Service, in accordance with Code Section 414(u).

J. Severance from Service Date. The earlier of (i) the date on which an Employee quits, is discharged, retires, or dies, or (ii) the first anniversary of the first date of any Absence from Service.

K. Year of Service. A 12 month computation period during which an Employee is credited with not less than 1,000 Hours of Service.

Section 1.40 Spouse. The lawful spouse of the Participant as determined under the law of the state where the Participant resides at the date of determination.

Section 1.41 Transfer Account. That portion of a Participant's Account credited with Transfer Contributions under Section 3.12 of the Plan, and adjustments relating thereto.

Section 1.42 Treasury Regulations. Regulations promulgated under the Internal Revenue Code by the Secretary of the Treasury.

Section 1.43 Trust or Trust Agreement. The assets of the Plan held by or in the name of the Trustee, and as governed by the Trust Agreement between Chesapeake Utilities Corporation and PNC Bank as set forth herein, and any amendments thereto or subsequent agreements established to replace or restate such Trust Agreement.

Section 1.44 Trustee. PNC Bank, or such other entity or person(s) that subsequently may be appointed by Chesapeake Utilities Corporation.

Section 1.45 Valuation Date. The last day of the Plan Year and each day on which the New York Stock Exchange is open for trading and on which the fair market value of Plan assets is determined.

Section 1.46 Terms Defined Elsewhere.

Absence from Service .... Section 1.39A.
Actual Contribution Percentage .... Schedule I.04A.(ii)
Actual Deferral Percentage .... Schedule I.01A.(i)
Aggregate Limit .... Schedule I.04A.(i)
Annual Additions .... Schedule I.07A.
Annuity Starting Date .... Section 5.02B.
Applicable Individual .... Section 8.07I.
Automatic Election Contributions .... Section 3.02C.
Authorized Leave of Absence .... Section 1.39B.
Before-Tax Contribution .... Section 3.02A.(i)
Break in Service .... Section 1.39C.
Cash-out Distribution .... Section 4.04 and Section 5.02A.
Catch-Up Contribution .... Section 3.02B.
Chesapeake Utilities Stock Fund .... Section 7.06
Claimant .... Section 8.10
Company .... Schedule I.07B.
Compensation .... Section 10.04C and Schedule I.07C.
Compensation Limitation .... Section 1.10B.
Contribution Percentage .... Schedule I.04A.(iii)
Contribution Percentage Amounts .... Schedule I.04A.(iv)
Defined Benefit Plan .... Schedule I.07D.
Defined Contribution Plan .... Schedule I.07E.
Determination Date .... Section 10.04G.
Determination Period .... Section 1.10B.
Designated Beneficiary .... Section 5.05B.(i)
Direct Rollover .... Section 6.04B.(iv)
Distributee .... Section 6.04B.(iii)
Distribution Calendar Year .... Section 5.05B.(ii)
Elective Contributions .... Section 1.10A.
Elective Deferrals .... Schedule I.03A.(i)
Eligible Participant .... Schedule I.04A.(v)
Eligible Retirement Plan .... Section 6.04B.(ii)
Eligible Rollover Distribution .... Section 6.04B.(i)

ARTICLE II
ELIGIBILITY AND PARTICIPATION

Section 2.01 ELIGIBILITY.

A. In General. Each Eligible Employee shall be eligible to become a Participant in the Plan. Each Eligible Employee who was a Participant in the Plan on the day before the Effective Date of this restated Plan shall continue as a Participant in this Plan as restated. Any other Eligible Employee who is employed by the Employer on and after January 1, 2011, shall become a Participant upon the completion of three months of Service.

B. Initial Entry Date. Upon satisfying the eligibility requirements stated in Section 2.01A above, an Eligible Employee shall become a Participant in the Plan on the first day of the Plan Year, or the first day of April, July or October of the Plan Year (each an "Initial Entry Date") coinciding with or next following the date on which such Eligible Employee meets the Plan's eligibility requirements, if such Eligible Employee is employed by the Employer on the applicable Initial Entry Date. If an Employee becomes an Eligible Employee after having completed three months of Service, he shall become a Participant upon the next succeeding Entry Date, if employed on that Entry Date. If an Eligible Employee elects not to be enrolled in the Plan as of his Initial Entry Date, he may enroll in the Plan as of any later day of the Plan Year.

Section 2.02 PARTICIPATION UPON RE-EMPLOYMENT. An Eligible Employee who had met all the requirements of Section 2.01A. above, but terminated employment prior to his Initial Entry Date, shall become a Participant on the date he is re-employed by the Employer, or his original Initial Entry Date, if later. An Eligible Employee who was a Participant shall again become a Participant on the date he is re-employed by the Employer. Any Eligible Employee who experiences a Severance from Employment with the Employer prior to satisfying the eligibility conditions of Section 2.01A. of the Plan must, upon becoming re-employed, satisfy the eligibility conditions of Section 2.01A. of the Plan as if he were a new Employee.

Section 2.03 ENROLLMENT. Prior to each Initial Entry Date, the Committee or its designee shall notify each Employee who is eligible to open a Before-Tax Contributions Account and shall explain the rights, privileges and duties of a Participant in the Plan. Each Eligible Employee may enroll as a Participant in the Before-Tax Contributions Account by properly completing the enrollment procedures established at the time by the Committee, or by following such other reasonable procedures as the Committee may implement. The Committee may establish additional rules and procedures governing the time and manner in which enrollment shall be processed. If a Participant does not timely complete the required enrollment forms or procedures to affirmatively elect either to make or not to make Before-Tax Contributions, he shall be automatically enrolled in the Plan in accordance with Section 3.02C or D hereof.

Section 2.04 TRANSFERS BETWEEN PARTICIPATING EMPLOYERS. For eligibility purposes, a Participant who transfers employment from one Participating Employer to another Participating Employer shall continue to be eligible to participate in the Plan if the Participant has previously met the requirements of Section 2.01 of the Plan. In accordance with the Plan and the Code, an Employee who is an Eligible Employee shall continue to be an Eligible Employee following a transfer between Participating Employers as if the Eligible Employee had performed all Service during the Plan Year for the Participating Employer to which the Eligible Employee is transferred.

Section 2.05 TRANSFERS BETWEEN CLASSES OF EMPLOYEES. For purposes of eligibility, in the case of an Employee who transfers from a class of Employees whose employment status is ineligible for participation in the Plan (e.g., collectively bargained employees who are ineligible to participate) to an eligible class of employment, such Employee shall become an Eligible Employee upon the satisfaction of the eligibility requirements in Section 2.01 of the Plan. In the case of an Eligible Employee who transfers to an ineligible employment status, such Employee shall cease to be an Eligible Employee under this Plan but shall remain a Former Participant under the Plan until such time as the Participant's Account is distributed.

ARTICLE III
CONTRIBUTIONS

Section 3.01 INDIVIDUAL ACCOUNTS. The Plan shall establish an Account for each Participant and Former Participant having an amount to his credit in the Trust. Each Account shall be divided into separate subaccounts for "Before-Tax Contributions," "Catch-Up Contributions," "Matching Contributions," and "Supplemental Employer Contributions," as defined below and any other types of contributions, as identified herein. If a Participant has made a "Rollover Contribution" or "Transfer Contribution" as defined below, or if the Employer elects to make "Qualified Non-Elective Contributions" or "Qualified Matching Contributions," as defined below, separate subaccounts shall be established for such contributions. Furthermore, if a Participant re-enters the Plan subsequent to a "Forfeiture Break in Service" (as defined in Section 4.02 of the Plan), a separate Account shall be maintained for the Participant's "pre-Forfeiture Break in Service Account" and a separate Account for his "post-Forfeiture Break in Service Account," unless the Participant's entire Account under the Plan is 100% Nonforfeitable. Allocations shall be made to the Accounts of the Participants in accordance with the provisions of Section 9.13 of the Plan. The Committee may direct the Trustee to maintain a temporary segregated investment Account in the name of a Participant to prevent a distortion of income, gain, or loss allocations under Section 9.13 of the Plan. The Committee shall ensure that records are maintained for all Account allocations and related recordkeeping activities.

Section 3.02 PARTICIPANT CONTRIBUTIONS.

A. Before-Tax Contributions.

(i) Contribution Limits. For any Plan Year, each Participant may elect to have allocated to his Account an amount of his Compensation for such Plan Year, which amount shall be a percent of his Compensation but not more than the lesser of $16,500 in 2011 (or such larger dollar amount as the Commissioner of the Internal Revenue may prescribe in accordance with Code Section 402(g)(5)) or 80% of his Compensation for such Plan Year (if such Participant is a Non-Highly Compensated Employee), or such lower percentage of Compensation for such Plan Year (if the Participant is a Highly Compensated Employee) as may be necessary to comply with the Code. Such amount shall be known as the Participant's "Before-Tax Contributions."

(ii) Amount of Compensation Deferral Contribution. A Participant's Compensation for a Plan Year shall be reduced by: (1) the amount of the deferral affirmatively elected by the Participant for such Plan Year; or (2) if applicable, the amount of deferral designated as the Automatic Election Contribution, as described below.

Except for occasional bona fide administrative considerations, contributions made pursuant to a Before-Tax Contribution election cannot precede the earlier of (i) the performance of Services relating to the contribution, or (ii) the date that the Compensation, which is subject to the Before-Tax Contribution election, would be payable to the Participant in the absence of a Before-Tax Contribution election.

B. Catch-Up Contributions. For any Plan Year, each Participant who has or will attain at least age 50 by the end of such Plan Year and who has elected to make Before-Tax Contributions at the maximum level available under the Plan or the Code, as applicable, may defer an additional amount of his Compensation for such Plan Year, which amount shall not exceed $5,500 in 2011 (or such larger dollar amount as prescribed in Code Section 414(v)). Such amount shall be known as the Participant's "Catch-Up Contributions." Such Catch-Up Contributions shall not be taken into account for purposes of Code Sections 402(g) and 415. The Plan shall not be treated as failing to satisfy the provisions of the Plan implementing the requirements of Code Sections 401(k)(3), 401(k)(11), 401(k)(12), 410(b) or 416, as applicable, by reason of the making of such Catch-Up Contributions. No Matching Contributions shall be contributed with respect to any Catch-Up Contributions elected or deemed to have been made by a Participant unless the Participant is a Non-Highly Compensated Employee and such contributions must be matched to achieve the required level of safe harbor contributions.

C. Automatic Election Contributions.

(i) Plan Years Prior to January 1, 2011. For any Eligible Employee, the Employer shall elect to reduce a Participant's Compensation by 2% for the sole purpose of making "Automatic Election Contributions" to the Participant's Before-Tax Contributions Account on his behalf for any Participant who does not affirmatively elect otherwise. An Eligible Employee may opt out of the Automatic Election Contribution prior to its application and an affected Participant may suspend or change the amount of Automatic Election Contributions at any time, but only on a prospective basis for the remainder of the Plan Year.

(ii) Administrative and Notice Requirements. The Committee shall administer Automatic Election Contributions in a uniform and nondiscriminatory manner with respect to newly eligible Participants (including rehired Participants) whose Before-Tax Contribution percentage does not equal or exceed 2%.

D. Qualified Automatic Contribution Arrangement ("QACA"). Effective January 1, 2011, the Plan shall implement a QACA intended to satisfy the requirements of Code Section 401(k)(13). The QACA provisions shall apply to an Eligible Employee who is first hired (or re-hired) by the Employer on or after January 1, 2011, and who has not made an affirmative election to make (or not to make) Before-Tax Contributions to the Plan as of the day before the date he becomes a Participant. The QACA provisions shall also apply to Eligible Employees who were first hired before January 1, 2011 and who have met the applicable eligibility requirements but who have not made an affirmative election to make (or not to make) Before-Tax Contributions to the Plan as of January 1, 2011. A Participant will cease being subject to the QACA if he makes an affirmative election regarding Before-Tax Contributions (either to make or not make such contributions). An Eligible Employee's "QACA Effective Date" shall be January 1, 2011 for Eligible Employees hired before January 1, 2011 who have met the eligibility requirements as of that date, and shall be his Initial Entry Date for all other Eligible Employees.

The QACA shall initially provide for a default Automatic Election Contribution percentage of 3% of an applicable Eligible Employee's Compensation, with such default percentage increasing, as provided below, beginning with the first pay period that ends in the second Plan Year following the Employee's QACA Effective Date, and with subsequent increases effective for the first pay period in each successive Plan Year for the next two Plan Years, until the Automatic Election Contribution deferral rate is 6%.

Automatic Election Contribution Percentage of Compensation	Effective Date of Automatic Election Contribution Percentage
4%	Second Plan Year following QACA Effective Date
5%	Third Plan Year following QACA Effective Date
6%	Fourth Plan Year following QACA Effective Date

Notwithstanding the foregoing, Automatic Election Contributions under the QACA will be reduced or stopped to the extent necessary to satisfy the limitations under Code Sections 401(a)(17), 402(g) and 415, as well as to satisfy any required suspension period following a hardship withdrawal. If the Automatic Election Contribution would have increased but for such a suspension, the rate of Automatic Election Contribution will reflect the increased rate when the suspension is over.

A Participant who experiences a Severance from Employment with the Employer after the Eligible Employee becomes a Participant shall again become a Participant in accordance with Section 2.02. If an Eligible Employee is rehired by an Employer more than one full Plan Year following the date of his Severance from Employment, the Automatic Election Contribution Percentage applicable to the Eligible Employee following his reemployment is 3%. If an Eligible Employee is rehired by an Employer within one Plan Year following the date of his Severance from Employment, the Automatic Election Contribution Percentage applicable to the Eligible Employee following his reemployment will be the percentage applicable at the time of his Severance from Employment, plus any increase in the percentage that would have occurred if he had not experienced a Severance from Employment.

The Automatic Election Contributions, including the QACA shall be effective as of a date following the lapse of a reasonable period of time after the Committee has provided such individual with a notice described below and the Employee has satisfied the Plan's eligibility requirements. The Committee shall provide newly eligible Participants at the time of hire or in advance of the effective date of the Automatic Election Contribution, including the QACA a notice explaining their right not to make Before-Tax Contributions or to alter the amount of such contribution, an explanation of the procedure for exercising that right and the timing for implementation of any such election, and the effect of not revoking the Automatic Election Contribution, including the QACA. The required notice shall be provided at least 30 days prior to the date Automatic Election Contributions shall commence or, if that is not administratively practicable for any reason, Automatic Election Contributions shall not begin earlier than the pay date for the second payroll period that begins after the date the notice was provided.

The provision of the notice shall be governed according to uniform and nondiscriminatory procedures established by the Committee. The content of the notice and procedures related to the Automatic Election Contributions and the QACA shall be consistent with Treasury Regulations issued under Code Section 401(k) and other guidance issued by the Internal Revenue Service.

E. Profit-Sharing Compensation Elections. Effective July 1, 2006, any Participant who is an Employee of BravePoint, Inc., may elect to make a separate Before-Tax Contribution with respect to any profit-sharing Compensation received during the Plan Year. Such election must be made prior to the receipt of such profit-sharing Compensation.

Section 3.03 CHANGES AND SUSPENSIONS OF BEFORE-TAX CONTRIBUTIONS AND CATCH-UP CONTRIBUTIONS. A Participant may change the rate of Before-Tax and/or Catch-Up Contributions to his Account at any time during each Plan Year, effective for the first payroll period for which it is administratively feasible to change the rate of such Participant's Before-Tax and/or Catch-Up Contributions, by communicating such rate change in accordance with uniform rules and procedures established by the Committee regarding the timing and manner of making such elections. In addition, a Participant may at any time elect to suspend all contributions to his Account by giving advance notice in any manner specified by the Committee in accordance with its uniform rules and procedures. An election to recommence contributions shall be effective for the first payroll period in which it is administratively feasible to begin deferral withholdings. All suspensions and recommencements of Before-Tax and/or Catch-Up Contributions shall be made in the manner and at the times specified in uniform rules and procedures established by the Committee, which rules and procedures may be changed from time to time.

Section 3.04 MATCHING, QUALIFIED MATCHING AND SAFE HARBOR MATCHING CONTRIBUTIONS.

A. Plan Years Prior to January 1, 2011. For each Plan Year, the Employer may contribute to each eligible Participant's Account a "Matching Contribution" in an amount described below. The Employer shall not make a Matching Contribution to the Trust for any Participant to the extent that the contribution would exceed the Participant's Maximum Permissible Amount as described in Schedule I.

(i) Matching Formula. Employer Matching Contributions will be made according to the following formula:

Years of Service + Age	Matching Percentage
Less than 40	100%
40 to less than 65	150%
65 to less than 80	175%
80 or more	200%

The Employer's Matching Contribution percentage will be based on the Participant's Before-Tax Contributions (excluding Catch-Up Contributions) up to a maximum of 6% of Compensation. A Participant's Years of Service with the Employer and the Participant's Age will be calculated on the first day of each calendar quarter. The Employer's Matching Contribution will be re-determined for each eligible Participant on the first day of each calendar quarter. Employer Matching Contributions up to 100% will be invested in Employer Securities. Employer Matching Contributions in excess of 100% may be invested by the Participant in any of the then available investment options provided under the Plan.

Employee Contractor Participants are not eligible to receive Employer Matching Contributions.

(ii) BravePoint, Inc. Participants. Notwithstanding the above, a Participant who is an Employee of BravePoint, Inc. shall receive an Employer Matching Contribution in the amount of 50% of the Participant's Before-Tax Contributions up to 6% of Compensation (excluding Catch-Up Contributions and Before-Tax Contributions made from profit-sharing amounts). Notwithstanding the foregoing, effective April 1, 2009, no additional Employer Matching Contributions shall be contributed to Participant Accounts for Employees of BravePoint, Inc.

B. Qualified Matching Contributions. If the Employer so elects, the Employer may also make Matching Contributions to the Plan which are "Qualified Matching Contributions." Qualified Matching Contributions shall mean Matching Contributions that are at all times Nonforfeitable and subject to the distribution requirements of Code Section 401(k) when made to the Plan. Additional contributions subject to these rules may be made by the Employer, or some or all of the existing Matching Contributions can be designated as fully vested and subject to the distribution restrictions, in order to satisfy these rules. Employee Contractor Participants are not eligible to receive Qualified Matching Contributions.

C. Safe Harbor Matching Contributions Effective for Plan Years Commencing on and after January 1, 2011.

(i) Amount. For Plan Years beginning on and after January 1, 2011, Matching Contributions sufficient to meet the "safe harbor" requirements of Code Sections 401(k)(13) and 401(m)(12) shall be made to each eligible Participant's

Account and shall be referred to as "Safe Harbor Matching Contributions." Specifically, for each eligible Employee who authorizes Before-Tax Contributions, or is deemed to have authorized Before-Tax Contributions under Section 3.02 of the Plan, the Employer will pay to the Trustee a Safe Harbor Matching Contribution equal to 100% of the Participant's Before-Tax Contributions up to 6% of his Compensation.

(ii) Notice. Effective with respect to each Plan Year in which the provisions of this Section 3.04C. are applicable, the Committee, or its designee, shall provide a safe harbor notice during the Safe Harbor Notice Period (as hereinafter defined) to each Employee who meets the applicable eligibility requirements of Section 2.01 of the Plan during such Plan Year.

For purposes hereof, the "Safe Harbor Notice Period" shall mean a period beginning 90 days before the first day of the applicable Plan Year and ending 30 days before the first day of the applicable Plan Year; provided, however, with respect to an Employee who becomes eligible to participate in the Plan during a given Plan Year in which the provisions of this Section 3.04C. or D. of the Plan are applicable, the Safe Harbor Notice Period shall begin 90 days before the day such Employee may first make Before-Tax Contributions under the Plan and shall end on the day such Employee may make Before-Tax Contributions under the Plan.

(iii) Nondiscrimination Tests. For Plan Years beginning on and after January 1, 2011, the Employer elects to treat the Plan as automatically satisfying the nondiscrimination in amount of Employer contribution requirements of Code Section 401(a)(4) with respect to Before-Tax Contributions.

Notwithstanding any provision of this Section 3.04C. to the contrary, the Employer reserves the right to suspend future Safe Harbor Matching Contributions at any time provided the procedures for implementing such suspensions are consistent with the Treasury Regulations.

D. Additional Matching Contributions. An Employer will not fail to meet the requirements of this Section merely because it makes Matching Contributions in addition to the Safe Harbor Matching Contributions, provided that:

(i) The additional Matching Contributions are not made with respect to Before Tax Contributions which exceed, in the aggregate, 6% of the eligible Participant's Compensation for the Plan Year;

(ii) The rate of additional Matching Contributions does not increase as the rate of Pre-Tax Contributions increases;

(iii) The rate of additional Matching Contributions for Highly Compensated Employees is not higher than the rate for Non-Highly Compensated Employees; and

(iv) The Plan does not permit such discretionary additional Matching Contributions to exceed, in total, 4% of a Participant's Compensation for the Plan Year.

Section 3.05 MATCHING CONTRIBUTION ALLOCATION AND ACCRUAL OF BENEFIT. Only Participants who have made Before-Tax Contributions during the Plan Year and who have satisfied the eligibility requirements set forth in Section 2.01 of the Plan shall be eligible to share in the allocation of the Matching Contributions as set forth in this Section 3.05. Catch-Up Contributions under this Plan shall not generally be eligible for Matching Contributions. In all cases, the allocation of Matching Contributions, Qualified Matching Contributions or Safe Harbor Matching Contributions shall be based on the amount or rate established in advance for such contributions relative to the Before-Tax Contributions being matched. Although Matching Contributions may be contributed periodically throughout the Plan Year, the allocation applicable to any Participant shall be adjusted as necessary to attain the appropriate allocation rate for the Plan Year as a whole; provided, however, that effective April 1, 2009, any Matching Contributions allocated to Participant Accounts for Employees of BravePoint, Inc. for the period from January 1, 2009 through March 31, 2009 shall be calculated only on Compensation earned and Before-Tax Contributions made to the Plan, respectively, through March 31, 2009. No Matching Contributions shall be made, however, with respect to "Excess Before-Tax Contributions."

Matching Contributions shall become Nonforfeitable in accordance with Section 4.01 of the Plan. In any event, Matching Contributions shall be fully vested and Nonforfeitable at (a) Early Retirement Age, (b) Normal Retirement Age, (c) on death prior to normal retirement (provided the Participant has not experienced a Severance from Employment prior to death), (d) on Severance from Employment due to Disability, (e) upon the complete or partial termination of the Plan, or (f) upon the complete discontinuance of Employer contributions. A Participant who dies on or after January 1, 2007, while performing Qualified Military Service (as defined in Code Section 414(u)) shall be treated as if he resumed employment with the Employer immediately prior to his death and then experienced a Severance from Employment on account of his death. A Participant who becomes Disabled on or after January 1, 2010, while performing Qualified Military Service (as defined in Code Section 414(u)) and does not return to active employment with the Employer as a result of the Disability shall be treated as if he resumed employment with the Employer immediately prior to becoming Disabled and then experienced a Severance from Employment due to his Disability.

Section 3.06 VOLUNTARY EMPLOYEE NONDEDUCTIBLE CONTRIBUTIONS. Participants shall not be permitted to make voluntary employee nondeductible (after-tax) contributions.

Section 3.07 QUALIFIED NON-ELECTIVE CONTRIBUTIONS. If it so elects, the Employer may make "Qualified Non-Elective Contributions" under the Plan on behalf of all Participants or all Participants who are Non-Highly Compensated Employees in order to satisfy either the Actual Deferral Percentage test or the Actual Contribution Percentage test. For purposes of this Article III, Qualified Non-Elective Contributions shall mean contributions (other than Matching Contributions or Qualified Matching Contributions) made by the Employer and allocated to Participants' Accounts that the Participants may not elect to receive in cash until distributed from the Plan; that are Nonforfeitable when made; and that are distributable only in accordance with the distribution provisions that are applicable to Before-Tax and Qualified Matching Contributions. Qualified Non-Elective Contributions shall be allocated to Participants' Accounts in the same proportion that each Participant's Compensation for the Plan Year for which the Employer makes the contribution bears to the total Compensation of all Participants for the Plan Year (or of all Non-Highly Compensated Participants, as applicable). Employee Contractor Participants are not eligible to receive Qualified Non-Elective Contributions.

Section 3.08 SUPPLEMENTAL EMPLOYER CONTRIBUTIONS. For each Plan Year, the Employer may contribute to the Trust amounts determined in its discretion based on profitability or other relevant factors. Such contributions will be in the form of "Supplemental Employer Contributions". The Employer shall not make a contribution to the Trust for any taxable year to the extent the contribution would exceed the maximum deduction limitations under Code Section 404. All contributions are conditioned on their deductibility under the Code. The amount contributed in any Plan Year may vary among the Employers or divisions of an Employer to the extent such variation does not violate the requirements of Code Section 401(a)(4) and 410(b). Whenever the Employer elects to contribute different amounts for a Plan Year on behalf of different Employers or divisions within an Employer, the Committee shall notify the Trustee in writing of the amount of the contribution allocable to each group and of the method of allocation for such group.

Section 3.09 SUPPLEMENTAL EMPLOYER CONTRIBUTION ALLOCATION. Supplemental Employer Contributions shall be allocated among Participants in accordance with such allocation formulas as the Employer in its sole discretion from time to time adopts. Such allocation formulas shall take into account such factors as the Employer deems appropriate and shall be administered on a nondiscriminatory basis. If the Employer fails to adopt an allocation formula for a Supplemental Employer Contribution for a Plan Year before such contribution is made, such Supplemental Employer Contribution shall be allocated to Participants who are actively employed by the Employer on the last day of the Plan Year in proportion to each Participant's Compensation for the Plan Year. Notwithstanding any other provision to the contrary, a Supplemental Contribution shall not be allocated to a Participant's Account to the extent the contribution would exceed the Participant's Maximum Permissible Amount as described in Schedule I.

A. Methods of Allocation of Employer Supplemental Contributions.

(i) Social Security Integration Allocation: All or a portion of an Employer Supplemental Contribution may be allocated as follows

Step One: Any Employer Supplemental Contributions made during the Plan Year will be allocated among each eligible Participant's Account, in the group of Participants for whom the Employer Supplemental Contribution was made, in the ratio that the sum of the Participant's total Compensation and Excess Compensation (as hereinafter defined) for the Plan Year bears to the sum of all such Participants' total Compensation and Excess Compensation for the Plan Year. However, if the amount allocated to Participants' Accounts under this Step One, as a percentage of the sum of their total Compensation and Excess Compensation, exceeds 5.7%, (or the percentage equal to the old-age insurance portion of the tax rate under Code Section 3111(a) in effect for the Plan Year, if greater), then the amount of contributions allocated under this Step One shall be reduced to an amount that results in an allocation, as a percentage of the sum of each Participant's total Compensation and Excess Compensation for the Plan Year, of no more than 5.7% (or the percentage equal to the old-age insurance portion of the tax rate under Code Section 3111(a) in effect for the Plan Year, if greater).

Step Two: Any Employer Contributions remaining after the allocation in Step One will be allocated among each eligible Participant's Account, in the group of Participants for whom the Employer Contribution was made, in the ratio that each such Participant's total Compensation for the Plan Year bears to the total Compensation of all such Participants for that Plan Year.

"Excess Compensation" means Compensation in excess of the taxable wage base, as determined under Section 230 of the Social Security Act, in effect on the first day of the Plan Year.

(ii) Uniform Points Allocation Formula: All or a portion of an Employer Supplemental Contribution for a Plan Year may be allocated among each eligible Participant's Account, in the group of Participants for whom the Employer Supplemental Contribution was made, in the ratio that each such Participant's total points bears to the total of all points awarded to all eligible Participants in the group, where each Participant receives one point for each year of age and one point for each Year of Service. Each eligible Participant's points shall be determined as of the beginning of the Plan Year for which the contribution is made and, if the Employer elects to contribute such amount throughout the Plan Year (rather than after the end of the Plan Year), each Participant's Points shall be re-determined as of the end of each calendar quarter within the Plan Year. Partial points credit shall also be given for partial completed Years of Service.

B. Accrual of Benefit. The Committee shall generally determine the accrual and allocation of a Participant's benefit on the basis of the Plan Year. However, if the Employer elects to make the Employer Supplemental Contribution throughout the Plan Year, the allocation period shall be each calendar quarter. In allocating an Employer Supplemental Contribution to a Participant's Account, the Committee shall take into account only Compensation paid to the Employee during the portion of the Plan Year during which the Employee was a Participant. Notwithstanding any other provision to the contrary, an Employer Supplemental Contribution shall not be allocated to a Participant's Account to the extent the contribution would exceed the Participant's "Maximum Permissible Amount" as described in Schedule I. In addition, to be eligible to receive an allocation of the Employer Supplemental Contribution, the Participant must be employed on the last day of each allocation period for the Plan Year (i.e., the last day of the Plan Year for an annual allocation period or the last day of each calendar quarter for a quarterly allocation period), unless the reason that the Participant is not so employed is due to his retirement after having attained Early or Normal Retirement Age, death or Disability. If necessary to satisfy the requirements of Code Section 410(b), the Plan shall suspend this accrual requirement for the number of Non-Highly Compensated Employees necessary to meet such requirement, beginning with the least highly compensated Non-Highly Compensated Employee.

Section 3.10 TIME OF PAYMENT OF CONTRIBUTION. The Employer may pay its Safe Harbor Matching and Employer Supplemental Contributions for each Plan Year in one or more installments of cash or Employer Securities without interest. The Employer must make its contribution which Participants have elected to defer under Section 3.02 of the Plan as soon as such amounts may reasonably be segregated from the Employer's general assets, but in no event later than 15 business days after the end of the calendar month in which such amounts were withheld from the Participant's Compensation, or such later time as may be permitted by regulations under ERISA and Code Section 401(k). The Employer must make the balance, if any, of its contribution to the Trustee within the time prescribed (including extensions) for filing its tax return for the taxable year for which it claims a deduction for its contribution, in accordance with Code Section 404(a)(6).

Section 3.11 ALLOCATION OF FORFEITURES. Subject to any restoration allocation required under Section 4.05 of the Plan, the Committee shall allocate and use all or a portion of the amount of a Participant's benefit forfeited under the Plan to reduce its Supplemental Employer Contributions, Matching Contributions and/or other contributions payable under the Plan, for the Plan Year in which the forfeiture occurs or any prior or future Plan Year, as determined by the Committee, or for the payment of administrative expenses under the Plan.

Section 3.12 ROLLOVER AND TRANSFER CONTRIBUTIONS. The Trustee is authorized to accept and hold as part of the Trust assets transferred from any other plan qualified under Code Sections 401(a) or 403(a) in connection with a merger or consolidation of such plan with or into the Plan pursuant to Section 12.06 of the Plan and as may be approved by the Committee. In addition, the Trustee shall also accept "rollover" amounts contributed directly by or on behalf of an Employee in accordance with procedures and rules established by the Committee in respect of a distribution made to or on behalf of such Employee from another plan qualified under Code Sections 401(a) or 403(a) pursuant to Section 12.06 hereof. All amounts so transferred to the Trust shall be held in segregated subaccounts and shall be referred to as "Transfer Contributions" if such amounts are subject to the special distribution rules for a qualified joint and survivor annuity described in Code Section 411(a)(11) and as "Rollover Contributions" if not subject to such rules.

Rollover Contributions must conform to rules and procedures established by the Committee, including rules designed to assure the Committee that the funds so transferred qualify as a Rollover Contribution under the Code. An Employee, after completing 90 days of Service, may make a Rollover Contribution to the Trust to the same extent and in the same manner as a Participant. If an Employee makes a Rollover Contribution to the Trust prior to satisfying the Plan's eligibility conditions, the Committee and Trustee must treat the Employee as a Participant for all purposes of the Plan, except that the Employee is not a Participant for purposes of making Before-Tax Contributions or sharing in Employer contributions under the Plan until he actually becomes a Participant in the Plan. If the Employee has a Severance from Employment prior to becoming a Participant, the Trustee will distribute his Rollover Account to him as if it were a Supplemental Employer Account.

Section 3.13 RETURN OF CONTRIBUTIONS. All contributions to the Plan are conditioned upon their deductibility under the Code. The Trustee, upon written request from the Employer, shall return to the Employer the amount of the Employer's contribution made by the Employer by mistake of fact or the amount of the Employer's contribution disallowed as a deduction under Code Section 404. The Trustee shall not return any portion of the Employer's contribution under this provision more than one year after;

A. the Employer made the contribution by mistake of fact; or

B. the disallowance of the contribution as a deduction, and then, only to the extent of the disallowance.

The Trustee shall not increase the amount of the Employer contribution returnable under this Section 3.13 for any earnings attributable to the contribution, but the Trustee shall decrease the Employer contribution returnable for any losses attributable to it. The Trustee may require the Employer to furnish it whatever evidence the Trustee deems necessary to enable the Trustee to confirm the amount the Employer has requested be returned is properly returnable under ERISA.

Section 3.14 FURTHER REDUCTIONS OF CONTRIBUTIONS. In addition to the reductions and recharacterizations provided for under Schedule I, in any Plan Year in which the Committee deems it necessary to do so to meet the requirements of the Code and the Treasury Regulations thereunder, the Committee may further reduce the amount of Before-Tax Contributions that may be made to a Participant's Account, or refund such amounts previously contributed.

ARTICLE IV
TERMINATION OF SERVICE; PARTICIPANT VESTING

Section 4.01 VESTING. A Participant's interest in his Before-Tax Contribution, Catch-up, Rollover, Transfer, and his Qualified Matching Contribution or Qualified Non-Elective Contribution Account(s), if any, shall at all times be fully vested and Nonforfeitable.

A Participant's interest in his Matching, Safe Harbor Matching and Supplemental Employer Contribution Account(s), if any, shall be fully vested and Nonforfeitable upon and after his attaining Early or Normal Retirement Age (if employed by the Employer on or after that date), or if his employment terminates as a result of death or Disability. Prior to January 1, 2011, if a Participant's employment terminated prior to Early Retirement Age for any reason other than death or Disability, then for each Year of Service, he received a Nonforfeitable percentage of his Matching and Supplemental Employer Contribution Account(s) (forfeiting the balance) equal to the following:

Years of Service	Percent Nonforfeitable
Less than one (1)	0%
One (1) but less than two (2)	20%
Two (2) but less than three (3)	40%
Three (3) but less than four (4)	60%
Four (4) but less than five (5)	80%
Five (5) or more	100%

Effective January 1, 2011, for any Participant hired before January 1, 2011, he shall receive a Nonforfeitable percentage of his Matching, Safe Harbor Matching and Supplemental Employer Contribution Account(s), if any, equal to the following:

Years of Service	Percent Nonforfeitable
Less than one (1)	0%
One (1) but less than two (2)	20%
Two (2) or more	100%

Effective January 1, 2011, for any Participant hired on or after January 1, 2011, he shall receive a Nonforfeitable percentage of his Matching, Safe Harbor Matching and Supplemental Employer Contribution Account(s), if any, equal to the following:

Years of Service	Percent Nonforfeitable
Less than two (2)	0%
Two (2) or more	100%

For purposes of this Section 4.01, the 12 month computation period for determining a Year of Service shall be based on the Participant's Employment (or Re-employment) Commencement Date and anniversaries of that date.

A Participant who dies on or after January 1, 2007, while performing Qualified Military Service (as defined in Code Section 414(u)) shall be treated as if he resumed employment with the Employer immediately prior to his death and then experienced a Severance from Employment on account of his death. A Participant who becomes Disabled on or after January 1, 2010, while performing Qualified Military Service (as defined in Code Section 414(u)) and does not return to active employment with the Employer as a result of the Disability shall be treated as if he resumed employment with the Employer immediately prior to becoming Disabled and then experienced a Severance from Employment due to his Disability.

Section 4.02 INCLUDED YEARS OF SERVICE – VESTING. For purposes of determining Years of Service under Section 4.01 above, the Plan shall take into account all Years of Service an Employee completes except any Year of Service after the Participant first incurs a "Forfeiture Break in Service." The Participant incurs a Forfeiture Break in Service when he incurs five consecutive Breaks in Service. This exception excluding Years of Service after a Forfeiture Break in Service shall apply for the sole purpose of determining the Nonforfeitable percentage of a Participant's Matching Account and Supplemental Employer Contribution Account which accrued for his benefit prior to the Forfeiture Break in Service.

Section 4.03 FORFEITURE OCCURS. A Participant's forfeiture, if any, of his Matching and Supplemental Employer Contribution Account shall occur under the Plan:

A. As of the Accounting Date of the Plan Year in which the Participant first incurs a Forfeiture Break in Service, or, if earlier and if applicable,

B. On the date the Participant receives (or is deemed to receive) a Cash-out Distribution, as defined in Section 4.04, of the Nonforfeitable percentage of his entire Account as a result of his termination of participation in the Plan in accordance with Section 4.04 below.

The Committee shall determine the percentage of a Participant's Matching and Supplemental Employer Contribution Account forfeiture, if any, under this Section 4.03 solely by reference to the vesting schedule of Section 4.01 of the Plan. A Participant shall not forfeit any portion of his Matching or Supplemental Employer Contribution Account for any other reason or cause except as expressly provided by this Section 4.03.

Section 4.04 CASH-OUT DISTRIBUTIONS TO PARTIALLY-VESTED PARTICIPANTS. If, pursuant to Article V of the Plan, a partially-vested Participant receives a Cash-out Distribution before he incurs a Forfeiture Break in Service, the Cash-out Distribution will result in an immediate forfeiture of the nonvested portion of the Participant's Matching and Supplemental Employer Contribution Account. A partially-vested Participant is a Participant whose Nonforfeitable percentage determined under Section 4.01 of the Plan is less than 100%. A "Cash-out Distribution" is a distribution of the entire present value of the Participant's Nonforfeitable Account Balance.

A "deemed" Cash-out Distribution rule applies to a 0% vested Participant. A 0% vested Participant is a Participant whose Account balance is entirely forfeitable at the time of his Severance from Employment. If the Participant's Account is not entitled to an allocation of Employer contributions for the Plan Year in which he has a Severance from Employment, the Committee will apply the deemed Cash-out Distribution rule as if the 0% vested Participant received a Cash-out Distribution on the date of the Participant's Severance from Employment. If the Participant's Account is entitled to an allocation of Employer contributions for the Plan Year in which he has a Severance from Employment, the Committee will apply the deemed Cash-out Distribution rule as if the 0% vested Participant received a Cash-out Distribution on the first day of the first Plan Year beginning after his Severance from Employment. For purposes of applying the restoration provisions of Section 4.05 below, the Committee will treat the 0% vested Participant as repaying his Cash-out Distribution on the first date of his re-employment with the Employer.

Section 4.05 RESTORATION OF FORFEITED PORTION OF ACCOUNT. A Participant who is re-employed after receiving a Cash-out Distribution (or deemed Cash-out Distribution) of the Nonforfeitable percentage of his Account shall have the right to repay the Trustee in cash the entire amount of the Cash-out Distribution he received, if the Committee must restore his Account under the requirements of this Section 4.05.

A. Restoration and Conditions upon Restoration. Subject to the conditions of this subsection, if the Participant makes the Cash-out Distribution repayment, the Committee shall restore his Account attributable to Employer contributions to the same dollar amount as the dollar amount of such portion of his Account on the Accounting Date, or other Valuation Date, immediately preceding the date of the Cash-out Distribution (or deemed Cash-out Distribution), unadjusted for any gains or losses occurring subsequent to that Accounting Date, or other Valuation Date. Notwithstanding such repayment, the Committee shall not restore a re-employed Participant's Account under the immediately preceding sentence if:

(i) the Participant's Account was 100% Nonforfeitable at the time of the Cash-out Distribution; or

(ii) the Participant incurred a Forfeiture Break in Service. This condition shall apply only if repayment is not made before the earlier of five years after the first date on which the Participant is re-employed by the Employer, or the close of the first period of five consecutive Breaks in Service commencing after the Cash-out Distribution.

B. Time and Method of Restoration. If neither of the two conditions preventing restoration of the Participant's Account applies, the Committee shall restore the Participant's Account as of the Plan Year Accounting Date coincident with or immediately following the repayment. To restore the Participant's Account, the Committee, to the extent necessary, shall allocate to the Participant's Account:

(i) first, the amount, if any, of Participant forfeitures the Committee would otherwise allocate under Section 3.11; and

(ii) second, the Employer contribution, if any, for the Plan Year to the extent made under a discretionary formula, if the Participant is otherwise eligible for such allocation.

To the extent the amount(s) available for restoration for a particular Plan Year are insufficient to enable the Committee to make the required restoration, the Employer shall contribute, without regard to any requirement or condition of Section 3.09, such additional amount as is necessary to enable the Committee to make the required restoration. If, for a particular Plan Year, the Committee must restore the Account of more than one re-employed Participant, then the Committee shall make the restoration allocation(s) to each such Participant's Account in the same proportion that a Participant's restored amount for the Plan Year bears to the restored amount for the Plan Year of all re-employed Participants. The Committee shall not take into account the allocation(s) under this Section 4.05 in applying the limitation on allocations described in Schedule I.

C. Segregated Account for Repaid Amount. Until the Committee restores the Participant's Account, the Trustee shall, at the direction of the Company or the Committee, invest the amount the Participant has repaid in a segregated Account maintained solely for that Participant. The Trustee shall invest the amount in the Participant's segregated Account in federally insured interest-bearing savings account(s), time deposit(s), or similar investments, including a money market or similar fund currently offered as an investment option under the Trust. Until commingled with the balance of the Trust Fund on the date the Committee restores the Participant's Account, the Participant's segregated Account shall remain a part of the Trust, but it alone shall share in any income it earns and it alone shall bear any expense or loss it incurs. The Company or the Committee shall direct the Trustee to repay to the Participant, as soon as is administratively practicable, the full amount of the Participant's segregated Account, if the Committee determines that one or more of the conditions of subsection A. of this Section 4.05 prevents restoration as of the applicable Accounting Date, notwithstanding the Participant's repayment.

ARTICLE V
TIME AND METHOD OF PAYMENT OF BENEFITS

Section 5.01 RETIREMENT. Upon termination of a Participant's employment for any reason after attaining Early or Normal Retirement Age, the Committee shall direct the Trustee to commence payment of the Participant's Account to him (or to his Beneficiary if the Participant is deceased), in accordance with the provisions of this Article V, as soon as administratively practicable but not later than 60 days after the close of the Plan Year in which the Participant's employment terminates. Notwithstanding the foregoing to the contrary, if a Participant elects to retire upon attaining his Early or Normal Retirement Age and such Participant's Nonforfeitable Account Balance exceeds $5,000, the Participant may elect to defer the receipt of his benefit distribution until his Required Beginning Date (as defined in Section 1.37 of the Plan). The form of payment shall be the same as for other distributions, as set forth in Sections 5.02 and 5.04 of the Plan. A Participant who remains in the employ of the Employer after attaining Early or Normal Retirement Age shall continue to participate in Employer contributions.

Section 5.02 DISTRIBUTION UPON SEVERANCE FROM EMPLOYMENT PRIOR TO NORMAL RETIREMENT AGE. Upon a Participant's Severance from Employment prior to attaining Early or Normal Retirement Age (for any reason other than death or Disability), the Committee, subject to the consent requirements of this Section 5.02, shall direct the Trustee to commence payment to the Participant of the value of his Nonforfeitable Account Balance as provided in this Section 5.02. The following rules and definitions shall apply to any such distribution:

A. "Cash-out Distribution." A Cash-out Distribution is a lump sum distribution of the Participant's Nonforfeitable Account Balance.

B. Consent. The Participant must consent in writing to a distribution (including the form of the distribution) if: (i) the Participant's Nonforfeitable Account Balance on the date the distribution commences exceeds $5,000, and (ii) the Committee directs the Trustee to make a distribution to the Participant prior to his attaining the later of Normal Retirement Age or age 62.

The consent of the Participant shall be obtained in writing within the 180-day period (90 days prior to January 1, 2007) ending on the Annuity Starting Date. The "Annuity Starting Date" is the first day of the first period for which an amount is payable under this Plan. The Plan Administrator shall notify the Participant of the right to defer distribution until the Participant's Nonforfeitable Account Balance is no longer immediately distributable. Such notice shall include a general description of the material features, and an explanation of the relative values of, the optional forms of benefit, if any, available under the Plan in a manner that would satisfy the notice requirements of Code Section 411(a)(11) and its applicable Treasury Regulations (including, effective January 1, 2007 a description of the consequences of failing to defer receipt of a distribution). Further, such notice shall be provided no less than 30 days and no more than 180 days (90 days prior to January 1, 2007) prior to the date of distribution. However, distribution may commence less than 30 days after the notice is provided if the Plan Administrator clearly informs the Participant that the Participant has a period of at least 30 days after receiving the notice to consider whether or not to elect a distribution, and the Participant, after receiving the notice, affirmatively elects a distribution. Notwithstanding the foregoing, the consent of the Participant shall not be required to the extent that a distribution is required to satisfy Code Sections 401(a)(9) or 415.

C. Time of Distribution of Account Balance. Upon Severance from Employment, other than for death or Disability, before Early or Normal Retirement Age, the Participant's Account balance shall be distributed as follows:

(i) If the Participant's Nonforfeitable Account Balance on the date the distribution commences is more than $1,000 but less than $5,000, any distribution shall be automatically rolled over to an individual retirement account in the name of the Participant in accordance with Code Section 401(a)(31)(B)(i) and related regulations, unless the Participant otherwise consents to the distribution.

(ii) If the Participant's Nonforfeitable Account Balance on the date the distribution commences is less than $1,000 ($5,000 prior to March 28, 2005), the Trustee shall pay such Nonforfeitable Account Balance in the form of a single, lump sum distribution as soon as administratively practicable after the Participant's Severance from Employment.

(iii) If the Participant's Nonforfeitable Account Balance on the date the distribution commences is greater than $5,000, such distribution shall be deferred until the Participant consents to the distribution or until the Participant's Early or Normal Retirement Age, if later.

D. Deferral of Distribution of Account Balance until Required Beginning Date. If the Participant does not file his written consent (if required) with the Trustee within the reasonable period of time stated in the consent form, the Trustee shall continue to hold the Participant's Account in trust until the Participant's Required Beginning Date. At that time, the Trustee shall commence payment of the Participant's Nonforfeitable value of his Account in accordance with the provisions of this Article V; provided, however, if the Participant dies after terminating employment but prior to his Required Beginning Date, the Committee, upon notice of the death, shall direct the Trustee to commence payment of the Participant's Nonforfeitable value of his Account to his Beneficiary in accordance with the provisions of Section 5.05 of the Plan.

A Participant elects to delay receiving a distribution of his Account may elect to receive a distribution of his Nonforfeitable Account Balance as soon as administratively practicable by properly completing the appropriate distribution election forms or procedures. If no such election is made, the Participant's Nonforfeitable Account Balance shall be paid as provided in Section 5.01 of the Plan.

Section 5.03 OTHER RULES GOVERNING THE TIME OF PAYMENT OF BENEFITS.

A. Minimum Legal Distribution Requirements. Unless the Participant elects otherwise in writing, the Committee shall direct the Trustee to commence distribution of a Participant's Nonforfeitable Account Balance not later than 60 days after the close of the Plan Year in which the later of the following events occurs:

(i) the date the Participant attains Early or Normal Retirement Age; or

(ii) the date the Participant dies, becomes Disabled, or otherwise incurs a Severance from Employment with the Employer.

In no event shall the Committee direct the Trustee to commence distribution, nor shall the Participant elect to have distribution commence, later than the Required Beginning Date. Furthermore, once distributions have begun to a Five-percent Owner, they must continue to be distributed, even if the Participant ceases to be a Five-percent Owner in a subsequent year.

B. In no event shall the Committee direct the Trustee to commence payment later than the time prescribed by this Article V or in a form not permitted hereunder. The Committee shall make its determinations under this Article V in a nondiscriminatory, consistent and uniform manner. The Participant shall be provided with the appropriate form to consent to the distribution direction, if required.

Section 5.04 FORM OF BENEFIT PAYMENT. A Participant shall receive payment of his Nonforfeitable Account Balance in a single lump sum in cash (and, where applicable, in Employer Securities) based upon the value of the Account on the Valuation Date coinciding with or immediately preceding the date the distribution is requested. A Participant (or Beneficiary or personal representative, as applicable) making application for distribution of his Account shall be entitled to elect, in accordance with the Plan's procedures, to have all those Employer Securities then held in or thereafter credited to his Account distributed to him in that form. If such an election is made, any Plan distribution made under this Article V shall consist (in part) of the number of Employer Securities (excluding any fractional share interest that shall be paid in cash) credited to the Participant's total Account, but only as part of any lump sum distribution payable hereunder, and if all such Participant's Employer Securities then being held in the Trust (fractional interests excepted) are to be distributed.

Payments from the Employer Common Stock Fund, as defined below, satisfy the distribution requirements of Code Section 4975(e)(7) (and the Code provisions incorporated therein) by providing payments in cash, or at the Participant's election, in shares to the extent of whole shares with fractional shares paid in cash. Further, payments from the Employer Common Stock Fund otherwise satisfy the distribution requirements of Code Section 4975(e)(7) (and the Code provisions incorporated therein) by providing for a lump sum distribution of a Participant's Account.

Section 5.05 REQUIRED MINIMUM DISTRIBUTIONS.

A. Effective Dates. The provisions of this Section 5.05 will apply for purposes of determining the required minimum distributions for calendar years beginning on or after January 1, 2003.

B. Definitions. For purposes of this Section 5.05, the following definitions shall apply:

(i) "Designated Beneficiary" is the individual who is designated as the Beneficiary under Section 1.04 of the Plan and is the Designated Beneficiary under Code Section 401(a)(9) and Treasury Regulations Section 1.401(a)(9)-1, Q&A-4.

(ii) "Distribution Calendar Year" is a calendar year for which a minimum distribution is required. For distributions beginning before the Participant's death, the first Distribution Calendar Year is the calendar year immediately preceding the calendar year which contains the participant's Required Beginning Date. For distributions beginning after the Participant's death, the first Distribution Calendar Year is the calendar year in which the distributions are required to begin. The required minimum distribution for the Participant's first Distribution Calendar Year will be made on or before the Participant's Required Beginning Date. The required minimum distribution for other Distribution Calendar Years, including the required minimum distribution for the Distribution Calendar Year in which the Participant's Required Beginning Date occurs, will be made on or before December 31 of that Distribution Calendar Year.

(iii) "Life Expectancy" is a beneficiary's life expectancy as computed by use of the Single Life Table in Treasury Regulations Section 1.401(a)(9)-9.

(iv) "RMD Account Balance" is the Account balance as of the last Valuation Date in the calendar year immediately preceding the Distribution Calendar Year (the "Valuation Calendar Year") increased by the amount of any contributions made and allocated or forfeitures allocated to the Account balance as of dates in the Valuation Calendar Year after the Valuation Date and decreased by distributions made in the Valuation Calendar Year after the Valuation Date. The Account balance for the Valuation Calendar Year includes any amounts rolled over or transferred to the Plan either in the Valuation Calendar Year or in the Distribution Calendar Year if distributed or transferred in the Valuation Calendar Year.

C. Time and Manner of Distribution.

(i) Required Beginning Date. The Participant's entire interest will be distributed, or begin to be distributed, to the Participant no later than the Participant's Required Beginning Date.

(ii) Death of Participant Before Distributions Begin. If the Participant dies before distributions begin, the Participant's entire interest will be distributed, or begin to be distributed, no later than as follows:

1. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, then, except as provided herein, distributions to the surviving Spouse will begin by December 31 of the calendar year

immediately following the calendar year in which the Participant died, or by December 31 of the calendar year in which the Participant would have attained age 70 ½, if later.

2. If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, then, except as provided herein, distributions to the Designated Beneficiary will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died.

3. If there is no Designated Beneficiary as of September 30 of the year following the year of the Participant's death, the Participant's entire interest will be distributed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

4. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary and the surviving Spouse dies after the Participant but before distributions to the surviving Spouse begin, this subsection C.(ii) other than sub-paragraph 1., will apply as if the surviving Spouse were the Participant.

For purposes of this Section 5.05C. and Sections 5.05G. and H. of the Plan, unless subsection 4. above applies, distributions are considered to begin on the Participant's Required Beginning Date. If subsection 4. applies, distributions are considered to begin on the date distributions are required to begin to the surviving Spouse under subsection 1.

D. Forms of Distribution. Unless the Participant's interest is distributed in the form of a single sum on or before the Required Beginning Date, as of the first Distribution Calendar Year distributions will be made in accordance with Sections 5.05E., 5.05F., 5.05G. and 5.05H. of the Plan.

E. Amount of Required Minimum Distributions for Each Distribution Calendar Year. During the Participant's lifetime, the minimum amount that will be distributed for each Distribution Calendar Year is the lesser of:

(i) the quotient obtained by dividing the RMD Account Balance by the distribution period in the Uniform Lifetime Table set forth in Treasury Regulations Section 1.401(a)(9)-9, using the Participant's age as of the Participant's birthday in the Distribution Calendar Year; or

(ii) if the Participant's sole Designated Beneficiary for the Distribution Calendar Year is the Participant's Spouse, the quotient obtained by dividing the RMD Account Balance by the number in the Joint and Last Survivor Table set forth in Treasury Regulations Section 1.401(a)(9)-9, using the Participant's and the Spouse's attained ages as of the Participant's and Spouse's birthdays in the Distribution Calendar Year.

F. Lifetime Required Minimum Distributions Continue Through Year of Participant's Death. Required minimum distributions will be determined under this subsection F. beginning with the first Distribution Calendar Year and up to and including the Distribution Calendar Year that includes the Participant's date of death.

G. Death On or After Date Distributions Begin.

(i) Participant Survived by Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is a Designated Beneficiary, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the RMD Account Balance by the longer of the remaining Life Expectancy of the Participant or the remaining Life Expectancy of the Participant's Designated Beneficiary, determined as follows:

1. The Participant's remaining Life Expectancy is calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

2. If the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, the remaining Life Expectancy of the surviving Spouse is calculated for each Distribution Calendar Year after the year of the Participant's death using the surviving Spouse's age as of the Spouse's birthday in that year. For Distribution Calendar Years after the year of the surviving Spouse's death, the remaining Life Expectancy of the surviving Spouse is calculated using the age of the surviving Spouse as of the Spouse's birthday in the calendar year of the Spouse's death, reduced by one for each subsequent calendar year.

3. If the Participant's surviving Spouse is not the Participant's sole Designated Beneficiary, the Designated Beneficiary's remaining Life Expectancy is calculated using the age of the Beneficiary in the year following the year of the Participant's death, reduced by one for each subsequent year.

(ii) No Designated Beneficiary. If the Participant dies on or after the date distributions begin and there is no Designated Beneficiary as of September 30 of the year after the year of the Participant's death, the minimum amount that will be distributed for each Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the RMD Account Balance by the Participant's remaining Life Expectancy calculated using the age of the Participant in the year of death, reduced by one for each subsequent year.

H. Death Before Date Distributions Begin.

(i) Participant Survived by Designated Beneficiary. Except as provided herein, if the Participant dies before the date distributions begin and there is a Designated Beneficiary, the minimum amount that will be distributed for each

Distribution Calendar Year after the year of the Participant's death is the quotient obtained by dividing the Participant's Account balance by the remaining Life Expectancy of the Participant's Designated Beneficiary, determined as provided in subsection G. above.

(ii) No Designated Beneficiary. If the Participant dies before the date distributions begin and there is no Designated Beneficiary as of September 30 of the year following the year of the Participant's death, distribution of the Participant's entire interest will be completed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

(iii) Death of Surviving Spouse Before Distributions to Surviving Spouse are Required to Begin. If the Participant dies before the date distributions begin, the Participant's surviving Spouse is the Participant's sole Designated Beneficiary, and the surviving Spouse dies before distributions are required to begin to the surviving Spouse under Section 5.05C.(ii)1., this Section will apply as if the surviving Spouse were the Participant.

I. General Rules.

(i) Precedence. The requirements of this Section 5.05 will supersede any contrary provisions of the Plan.

(ii) Requirements of Treasury Regulations Incorporated. All distributions required under this Section 5.05 will be determined and made in accordance with the Treasury Regulations under Code Section 401(a)(9).

(iii) TEFRA Section 242(b)(2) Elections. Notwithstanding the other provisions of this Section 5.05, distributions may be made under a designation made before January 1, 1984, in accordance with section 242(b)(2) of the Tax Equity and Fiscal Responsibility Act ("TEFRA") and the provisions of the Plan that relate to TEFRA Section 242(b)(2).

(iv) If requested by the Participant, the Committee may compute the minimum distribution for a calendar year subsequent to the first calendar year for which the Plan requires a minimum distribution by redetermining the applicable life expectancy. However, the Committee may not redetermine the joint life and last survivor expectancy of the Participant and a nonspouse Beneficiary in a manner that takes into account any adjustment to a life expectancy other than the Participant's life expectancy.

J. Distributions During Qualified Military Service. In the case of a Participant who dies on or after January 1, 2007, while performing Qualified Military Service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of Qualified Military Service as provided by Code Section 414(u)) that are provided under the Plan assuming the Participant resumed employment with the Employer and then experienced a Severance from Employment on account of death. However, the foregoing shall not provide any additional benefit accruals, and the deemed resumption of employment of the Participant shall be applied only to determine the eligibility of a Beneficiary for any pre-retirement death benefits, and only to the extent required by published guidance, as incorporated herein.

K. 2009 Required Minimum Distributions. Notwithstanding anything in this Section 5.05 to the contrary, a Participant or Beneficiary who would have been required to receive required minimum distributions for 2009 but for the enactment of Code Section 401(a)(9)(H) ("2009 RMDs"), and who would have satisfied that requirement by receiving distributions that are (1) equal to the 2009 RMDs or (2) one or more payments in a series of substantially equal distributions (that include the 2009 RMDs) made at least annually and expected to last for the life (or life expectancy) of the Participant, the joint lives (or joint life expectancy) of the Participant and the Participant's designated Beneficiary, or for a period of at least 10 years ("Extended 2009 RMDs"), will receive those distributions for 2009 unless the Participant or Beneficiary chooses not to receive such distributions. Participants and Beneficiaries described in the preceding sentence will be given the opportunity to elect to stop receiving the distributions described in the preceding sentence.

Section 5.06 DESIGNATION OF BENEFICIARY. A Participant may, from time to time, designate in writing a Beneficiary or Beneficiaries, contingently or successively, to whom the Trustee shall pay his Account in the event of his death. A Participant's Beneficiary designation shall not be valid unless the Participant's Spouse consents (in accordance with the requirements of Code Section 417) to the Beneficiary designation. A Participant's Beneficiary designation does not require spousal consent if the Participant's Spouse is the Participant's designated Beneficiary. The Committee shall prescribe the form for the written designation of Beneficiary and, upon the Participant's filing the form with the Committee, the Participant shall effectively revoke all designations filed prior to that date by the same Participant.

The termination of a Participant's marriage shall not automatically result in a revocation or change of the Participant's Beneficiary designation. Further, no provision in any court order, judgment, decree, or similar document shall be effective to revoke or change a Participant's Beneficiary designation, except to the extent that such order, judgment or decree is determined to be a qualified domestic relations order that must be honored by the Plan. A Participant's Beneficiary designation may be changed only by the Participant making a new Beneficiary designation in writing on the form required by the Committee and filing the form with the Committee. Any new Beneficiary designation, change or revocation by a Participant shall be effective only if it is received by the Committee before the Participant's death.

Section 5.07 FAILURE OF BENEFICIARY DESIGNATION. If a Participant fails to name a Beneficiary in accordance with Section 5.06 of the Plan, or if the Beneficiary (and contingent Beneficiary, if any) named by a Participant predeceases him, then the Trustee shall pay the Participant's Account in a single lump sum to the Participant's surviving Spouse, if any, and if there is no surviving Spouse, to the Participant's estate.

Section 5.08 SPECIAL RULES FOR TRANSFER ACCOUNTS. Notwithstanding any provision of this Article V to the contrary, with respect to any Participant who has one or more

Transfer Accounts consisting in whole or in part of Transfer Contributions which, by operation of relevant law and regulation (including, but not limited to, ERISA and the Code), must be distributed or made available under the same terms and conditions under which amounts held thereunder were previously held (prior to their becoming Transfer Contributions) to the extent that such terms and conditions must be preserved in order to comply with Code Section 411(d)(6), the Committee shall, upon the written request of the Participant (in the case of optional forms of benefit), cause the Trustee to distribute or make available such Transfer Contributions at such times and in such manner as may be so required.

Section 5.09 DISTRIBUTIONS UNDER DOMESTIC RELATIONS ORDERS. Nothing contained in this Plan shall prevent the Trustee from complying with the provisions of a qualified domestic relations order (as defined in Code Section 414(p)). This Plan specifically permits distribution to an alternate payee under a qualified domestic relations order at any time, irrespective of whether the Participant has attained his earliest retirement age (as defined under Code Section 414(p)) under the Plan. A distribution to an alternate payee prior to the Participant's attainment of the earliest retirement age is available only if the order specifies distribution at that time or permits an agreement between the Plan and the alternate payee to authorize such an earlier distribution. In addition, if the present value of the alternate payee's benefits under the Plan exceeds $5,000 and the order requires, the alternate payee must consent to any distribution occurring prior to the Participant's attainment of the earliest retirement age. Nothing in this Section gives a Participant the right to receive a distribution at a time not permitted under the Plan, nor does this Section 5.09 give the alternate payee the right to receive a form of payment not permitted under the Plan.

The Committee shall establish reasonable procedures to determine the qualified status of a domestic relations order. Upon receiving a domestic relations order, the Committee, or its designee, shall promptly notify the Participant and any alternate payee named in the order, in writing, of the receipt of the order and the Plan's procedures for determining the qualified status of the order. Within a reasonable period of time after receiving the domestic relations order, the Committee, or its designee, shall determine the qualified status of the order and shall notify the Participant and each alternate payee, in writing, of its determination. The Committee, or its designee, shall provide notice under this paragraph by mailing to the individual's address specified in the domestic relations order, or in a manner consistent with Department of Labor Regulations.

If any portion of the Participant's Nonforfeitable Account Balance is payable during the period the Committee, or its designee, is making its determination of the qualified status of the domestic relations order, the Trustee shall segregate the amounts payable in a separate account and invest the segregated account solely in fixed income investments or maintain a separate bookkeeping account of said amounts. If the Committee, or its designee, determines the order is a qualified domestic relations order within 18 months of the first date on which payments were due under the terms of the order, the Trustee shall distribute the separate account in accordance with the order. If the Committee, or its designee, does not make its determination of the qualified status of the order within the above-described 18-month period, the Trustee shall distribute the segregated account in the manner the Plan would distribute it if the order did not exist, and shall apply the order prospectively if the Committee later determines the order is a qualified domestic relations order.

To the extent it is not inconsistent with the provisions of the qualified domestic relations order, the Trustee shall invest any partitioned amount in a segregated subaccount or separate account and invest the account in a money market investment option or in other fixed income investments. A segregated subaccount shall remain a part of the Trust, but it alone shall share in any income it earns, and it alone shall bear any expense or loss it incurs.

The Trustee shall make any payment or distributions required under this Section by separate benefit checks or other separate distribution to the alternate payee(s).

Section 5.10 LOST PARTICIPANT OR BENEFICIARY. The Account of a Participant shall be forfeited if the Committee, after reasonable effort, is unable to locate the Participant or his Beneficiary to whom payment is due. The amount of the forfeiture shall reduce the Employer's contributions under Section 3.11 of the Plan (subject to Section 4.05 of the Plan, as applicable), as elected by the Employer. However, any such forfeited Account will be reinstated and become payable if a claim is made by the Participant or Beneficiary for such Account. The Committee may prescribe uniform and non-discriminatory rules for carrying out this provision.

Section 5.11 FACILITY OF PAYMENT. If any person entitled to receive any amount under the provisions of this Plan is determined to be incapable of receiving or disbursing the same by reason of minority, illness or infirmity, mental incompetency, or incapacity of any kind, the Committee may, in its discretion, direct the Trustee to take any one or more of the following actions:

A. to apply such amount directly for the comfort, support and maintenance of such person;

B. to reimburse any person for any such support theretofore supplied to the person entitled to receive any such payment; or

C. to pay such amount to any person selected by the Committee to disburse it for such comfort, support and maintenance, including without limitation, any relative who has undertaken, wholly or partially, the expense of such person's comfort, care and maintenance, or any institution in whose care or custody the person entitled to the amount may be. The Committee may, in its discretion, deposit any amount due to a minor to his credit in any savings or commercial bank of the Committee's choice.

Section 5.12 NO DISTRIBUTION PRIOR TO SEVERANCE FROM EMPLOYMENT, DEATH OR DISABILITY. Except as provided below, Before-Tax, Catch-Up, Qualified Non-Elective, Qualified Matching Contributions, Safe Harbor Matching Contributions and income allocable to each, are not distributable to a Participant or his Beneficiary or Beneficiaries, in accordance with such Participant's or Beneficiary's election, earlier than upon Severance from Employment, death or Disability.

Such amounts may also be distributed upon:

A. termination of the Plan without the establishment of another defined contribution plan, as defined in the Code and applicable Treasury Regulations; or

B. with respect to Before-Tax and Catch-Up Contributions only, the hardship of the Participant, as described in Section 6.01 of the Plan.

All distributions that may be made pursuant to one or more of the foregoing distributable events are subject to the spousal and Participant consent requirements (if applicable) contained in Code Sections 401(a)(11) and 417.

Notwithstanding the foregoing, a Participant may receive a distribution of his Before-Tax Contributions, including Catch-Up, Matching, Safe Harbor Matching, Employer Supplemental and Rollover Contributions upon attaining age 59½.

Notwithstanding the foregoing, effective January 1, 2009, as required by Code Section 414(u), as amended by the HEART Act, a Participant in Qualified Military Service (within the meaning of Code Section 414(u)) shall be treated as having incurred a Severance from Employment for purposes of eligibility to receive a distribution from his Account. However, if a Participant obtains a distribution according to the foregoing provision, such Participant's Before-Tax Contributions and Catch-Up Contributions to this Plan shall be suspended for 6 months following the date of the distribution.

Section 5.13 WRITTEN INSTRUCTION NOT REQUIRED. Any elections made or distributions processed under this Article V may be accomplished through telephonic, electronic or similar instructions in accordance with the rules and procedures established by the Committee, to the extent they are consistent with the requirements of the Code and ERISA. Notwithstanding the foregoing, however, Spousal consents and waivers, to the extent required, may only be granted in writing.

ARTICLE VI
WITHDRAWALS; DIRECT ROLLOVERS AND WITHHOLDING; LOANS

Section 6.01 HARDSHIP WITHDRAWALS. Subject to the restrictions set forth in Section 5.12 of the Plan, upon the application of any Participant, the Committee, in accordance with a uniform, nondiscriminatory policy, may permit such Participant to withdraw all or a portion of his Before-Tax and Catch-up Contributions including earnings thereon (but excluding all earnings credited thereto after December 31, 1988), if the withdrawal is necessary due to the immediate and heavy financial need of the Participant.

A. Only distributions made pursuant to conditions arising under the following circumstances shall be conclusively considered to be made on account of immediate and heavy financial need:

(i) alleviating extraordinary financial hardship arising from deductible medical expenses (within the meaning of Code Section 213(d) determined without regard to whether the expenses exceed 7.5% of adjusted gross income) previously incurred by the Participant or his Spouse, children or other dependents (as defined in Code Section 152, and for taxable years beginning on or after January 1, 2005, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)) or necessary for such persons to obtain such care;

(ii) purchasing real property (excluding mortgage payments) that is to serve as the principal residence of the Participant;

(iii) expenditures necessary to prevent eviction from the Participant's principal residence or foreclosure of a mortgage on the same;

(iv) financing the tuition and related educational fees, including room and board for the next 12 months of post-secondary education for the Participant, his Spouse, his children or other dependents (as defined in Code Section 152, and for taxable years beginning on or after January 1, 2005, without regard to Code Sections 152(b)(1), (b)(2), and (d)(1)(B)); or

(v) for Plan Years beginning on and after January 1, 2006, payments for funeral or burial expenses for the Participant's deceased parent, Spouse, child or dependent (as defined in Code Section 152 without regard to Code Section 152(d)(1)(B));

(vi) for Plan Years beginning on and after January 1, 2006, expenses to repair damage to the Participant's principal residence that would qualify for a casualty loss deduction under Code Section 165 (determined without regard to whether the loss exceeds 10% of adjusted gross income); or

(vii) any other reason deemed to be an immediate and heavy financial need by the Secretary of the Treasury.

B. A distribution will be considered to be necessary to satisfy an immediate and heavy financial need of the Participant only if:

(i) the Participant has obtained all distributions other than hardship distributions, and all nontaxable loans, currently available under all plans maintained by the Employer (effective January 1, 2006, including all qualified and nonqualified plans of deferred compensation and a cash or deferred arrangement that is part of a cafeteria plan under Code Section 125 (but excluding mandatory employee contribution portions of a defined benefit plan or health and welfare plan) as well as the distribution of ESOP dividends under Code Section 404(k), or by borrowing from commercial sources on reasonable commercial terms in an amount sufficient to satisfy the need;

(ii) all plans maintained by the Employer (effective January 1, 2006, including any stock option, stock purchase or similar plan or arrangement) provide that the Participant's Before-Tax Contributions or other Participant contributions will be suspended for 6 months after the receipt of the hardship distribution (which this Plan hereby so provides);

(iii) the distribution is not in excess of the amount necessary to satisfy the immediate and heavy financial need, including any amounts necessary to pay any federal, state, or local income taxes or penalties reasonably anticipated to result from the distribution; and

(iv) the need cannot be satisfied through reimbursement, compensation by insurance, liquidation of the Participant's assets or the cessation of Before-Tax Contributions, Catch-up Contributions or other Participant Contributions.

C. A Participant making an application under this Section 6.01 shall have the burden of presenting to the Committee evidence of such need, and the Committee shall not permit withdrawal under this Section without first receiving such evidence. A Participant shall also be required to obtain the consent of the Participant's Spouse, if any, prior to receiving a hardship withdrawal. If a Participant's application for a hardship withdrawal is approved, the Trustee shall make payment of the approved amount of the hardship withdrawal to the Participant.

<u>Section 6.02</u> <u>SPECIAL WITHDRAWAL RULES APPLICABLE TO ROLLOVER CONTRIBUTIONS</u>. A Participant who maintains a Rollover Account in the Plan may elect to make withdrawals from his Rollover Account. Any election to begin, change or cease withdrawals shall be made in accordance with procedures established by the Committee or in such other manner as permitted by the Committee. Payment of amounts so requested shall be made within an administratively reasonable period of time after the withdrawal has been requested. The Committee may establish other rules of uniform applicability regarding the timing of and procedures for such withdrawals.

<u>Section 6.03</u> <u>SPECIAL WITHDRAWAL RULES APPLICABLE TO TRANSFER ACCOUNTS</u>. Notwithstanding any other Plan provision to the contrary, if the Internal Revenue

Service requires distributions to be made (or offered) with respect to any or all amounts held on behalf of a Participant with respect to a predecessor or transferor plan, as a condition of preserving the tax-qualified status of this Plan or of said predecessor or transferor plan, or if a court of competent jurisdiction issues an order or decree in respect of the Plan or its fiduciaries which is determined under relevant federal law to be enforceable, and which compels the distribution of a Participant's Plan interest, the Committee will be entitled to direct the prompt distribution (or offer of distribution) of such amounts.

Section 6.04 DIRECT ROLLOVER AND WITHHOLDING RULES.

A. In General. Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Article, a Distributee may elect, at the time and in the manner prescribed by the Plan Administrator, to have any portion of an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover. The Plan Administrator may establish rules and procedures governing the processing of Direct Rollovers and limiting the amount or number of such Direct Rollovers in accordance with applicable Treasury Regulations. Distributions not transferred to an Eligible Retirement Plan in a Direct Rollover shall be subject to income tax withholding as provided under the Code and applicable state and local laws, if any.

B. Definitions.

(i) "Eligible Rollover Distribution." Any distribution of all or any portion of the balance to the credit of the Distributee, except that an Eligible Rollover Distribution does not include: (1) any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for life (or life expectancy) of the Distributee or the joint lives (or joint life expectancies) of the Distributee and the Distributee's designated beneficiary, or for a specified period of ten years of more; (2) any distribution to the extent such distribution is required under Code Section 401(a)(9); (3) any hardship distribution received on and after January 1, 2002 (limited to hardship amounts described in Code Sections 401(k)(2)(B)(i)(IV) or 403(b)(11)(B) received from January 1, 2000 to December 31, 2001); (4) any loan that is treated as a distribution under Code Section 72(p) and not excepted by Code Section 72(p)(2), or a loan that is a deemed distribution; and (5) any corrective distribution provided under Sections I.02, I.03C. and I.05 and of Schedule I to the Plan, if applicable. Notwithstanding the foregoing, any portion of a distribution that consists of after-tax employee contributions that are not includible in gross income may be transferred only to an individual retirement account or annuity described in Code Sections 408(a) or 408(b) or a qualified trust described in Code Sections 401(a) or 403(a) that agrees to separately account for amounts so transferred, including separately accounting for the portion of such distribution that is includible in gross income and the portion of such distribution that is not so includible. However, the portion of any distribution on and after January 1, 2007 that consists of after-tax contributions which are not includible in gross income may be transferred (in a direct trustee-to-trustee transfer) to a qualified defined benefit plan or a Code Section 403(b) tax-sheltered annuity that agrees to separately account for amounts so transferred and (and the earnings thereon), including separately accounting for the portion of such distribution that is includible in gross income and the portion of such distribution which is not so includible. In addition, 2009 RMDs and Extended 2009 RMDs, as defined in Section 4.05K. of the Plan, may be treated as Eligible Rollover Distributions in 2009.

(ii) "Eligible Retirement Plan." An individual retirement account described in Code Section 408(a), an individual retirement annuity described in Code Section 408(b), an annuity plan described in Code Section 403(a), a qualified trust described in Code Section 401(a), an annuity contract described in Code Section 403(b), an eligible plan under Code Section 457(b) which is maintained by a state, political subdivision of a state or any agency or instrumentality of a state or political subdivision of a state and which agrees to separately account for amounts transferred into such plan from the Plan, and, effective January 1, 2008, a Roth individual retirement arrangement within the meaning of Code Section 408A, and that accepts the Distributee's Eligible Rollover Distribution.

(iii) "Distributee." An Employee or former Employee. In addition, the Employee's or former Employee's surviving Spouse and the Employee's or former Employee's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Code Section 414(p), are Distributees with regard to the interest of the Spouse or former Spouse. Effective for distributions on and after January 1, 2009, a Distributee includes the Participant's non-spouse Beneficiary.

(iv) "Direct Rollover." A payment by the Plan to the Eligible Retirement Plan specified by the Distributee. In the case of a non-spouse Beneficiary, a Direct Rollover may be made only to an individual retirement account or annuity described in Code Sections 408(a) or 408(b) that is established on behalf of the designated Beneficiary and that will be treated as an inherited individual retirement account within the meaning of Code Section 408(d)(3)(C) pursuant to the provisions of Code Section 402(c)(11). Also, in this case, the determination of any required minimum distribution under Code Section 401(a)(9) that is ineligible for rollover shall be made in accordance with Notice 2007-7, Q&A 17 and 18, 2007-5 I.R.B. 395, or with any subsequent published guidance.

Section 6.05 LOANS TO PARTICIPANTS. Loans may be granted to any Participant under the Plan in accordance with applicable rules under the Code and ERISA, and the provisions of this Section.

A. General Rules. The Committee shall establish the procedures a Participant must follow to request a loan from his Nonforfeitable Account Balance under the Plan. Loans shall be made available to all Participants on a reasonably equivalent basis; provided, however, that a Plan loan will not be made available to a Former Participant, unless such Former Participant is actively employed by a Related Employer.

B. In no event will the total of any outstanding loan balances made to any Participant, including any interest accrued thereon, when aggregated with corresponding loan balances of the Participant under any other plans of the Employer or any Affiliate, exceed the lesser of (i) or (ii), below:

(i) $50,000, reduced by the excess (if any) of the highest outstanding balance of such loans during the one-year period ending on the day before the date any such loan is made over the outstanding balance of such loans on the date any such loan is made; or

(ii) one-half of the value of the vested portion of the Participant's Account. For purposes of this Section, the value of a Participant's Account shall be determined as of the Valuation Date coinciding with or next preceding the date on which a properly completed loan request is received by the Committee (or its delegate) or the Trustee, as applicable.

The minimum amount of any loan shall be $1,000.

C. Term of Loan. The term of any loan shall be determined by mutual agreement between the Committee or Trustee and the Participant. Every Participant who is granted a loan shall receive a statement of the charges and interest rates involved in each loan transaction and periodic statements reflecting the current loan balance and all transactions with respect to that loan to date. Except for loans used to acquire any dwelling unit which within a reasonable time (determined at the time the loan is made) is to be used as the principal residence of the Participant, the term of any loan shall not exceed five years. The term of any loan which within a reasonable time (determined at the time the loan is made) is to be used as the principal residence of the Participant shall not exceed 15 years. All loans shall be amortized in level payments over the term of the loan, or in accordance with other procedures established by the Employer or the Committee.

D. Security. Each loan made hereunder shall be evidenced by a credit agreement with, or a note payable to the order of, the Trustee and shall be secured by adequate collateral. Notwithstanding the foregoing sentence, no more than one-half of the vested portion of the Participant's Nonforfeitable Account Balance (determined as of the Valuation Date coinciding with or next preceding the date on which the loan is made) shall be used to secure any loan.

E. Interest. Each Participant loan shall be considered an investment of the Trust, and interest shall be charged thereon at a reasonable rate established by, or in accordance with procedures approved by, the Committee commensurate with the interest rates then being charged by persons in the business of lending money under similar circumstances. Notwithstanding the foregoing sentence, if necessary, the Committee will reduce the interest rate of an outstanding Participant loan to 6% during a period of qualified military leave as defined in Code Section 414(u)(5), to the extent required by the Soldiers' and Sailors' Civil Relief Act of 1940. Participant loans under this Section will be considered the directed investment of the Participant requesting such loan, and interest paid on such loan will be allocated to the Account of the Participant-borrower.

F. Repayment Terms.

(i) Generally. The terms and conditions of each loan shall be determined by mutual agreement between the Committee or Trustee and the Participant. The Committee shall take all necessary actions to ensure that each loan is repaid on schedule by its maturity date, including requiring repayment of the loan by payroll deduction whenever possible.

(ii) Suspension of Loan Payments during Qualified Military Leave. Loan payments shall be suspended during a period of "qualified military service," as defined in Code Section 414(u)(5). The duration of such period of service shall not be taken into account in determining the maximum permissible term of the loan under Code Section 72(p) and the regulations promulgated thereunder. Following the Participant's timely reemployment after a period of qualified military service, loan payments shall resume at an amount no less than required by the terms of the original loan, and at a frequency such that the loan will be repaid in full during a period that is no longer than the "latest permissible term of the loan" (defined as the latest date permitted under Code Section 72(p)(2)(B) plus the period of suspension due to such military service).

G. Restrictions on Loans. No Participant shall have more than one loan under this Section outstanding at any time.

H. Nondiscrimination. Loans will not be made available to Highly Compensated Employees in an amount greater than the amount made available to other Employees.

I. Default. Failure to make a payment within 90 days of the date payment is due will generally constitute a default, unless loan procedures adopted pursuant to this Section 6.05 and applicable law do not so require. The Committee may establish additional rules and procedures for handling loan defaults, including, but not limited to, restrictions on future borrowing.

J. Procedure. The Committee will establish nondiscriminatory policies and procedures to administer Participant loans.

Section 6.06 WITHDRAWAL OF ESOP DIVIDENDS. A Participant may, in a manner approved by the Committee, elect to receive in cash dividends paid with respect to Employer Securities held by the Employer Common Stock Fund as defined below. Such election may be made even if the Participant is currently employed by the Employer. The Trustee, as directed by the Employer, may pay such dividends currently (or within 90 days after the end of the Plan Year in which the dividends are paid to the Trust) in cash to Participants, or the Company may pay such dividends directly to Participants.

If a Participant does not elect to receive dividends in cash (or affirmatively elects, in a manner approved by the Committee, not to receive dividends in cash), dividends attributable to the Participant's interest in the Employer Common Stock Fund will be reinvested on behalf of the Participant in the Employer Common Stock Fund. The amount of dividends paid to or reinvested on behalf of a Participant under this Section 6.06 will be proportionate to the Participant's interest in the Employer Common Stock Fund on the last business day preceding the ex-dividend date, or as of such other date as established by the Employer. Any dividend that is paid to a Participant or reinvested on behalf of the Participant in the Employer Common Stock Fund shall be fully and immediately vested without regard to the vesting schedule in Section 4.01 of the Plan or whether the Participant is vested in the Employer Securities with respect to which the dividend is paid. Notwithstanding the foregoing, a Participant who elects to receive a hardship distribution under Section 6.01 of the Plan, must elect to receive any available ESOP dividends paid to the Participant in cash and may not elect (either affirmatively or by default) to have such dividends reinvested in the Plan.

To administer this Section 6.06, the Employer is authorized to establish a separate fund to hold dividends paid with respect to Employer Securities held by the Employer Common Stock Fund for the period of time before such dividends are distributed or reinvested. Any investment income attributable to such fund will be credited to and considered income of the Employer Common Stock Fund.

Sections 7.06, 8.05, 8.07 and this Section 6.06 of the Plan are intended to satisfy the requirements provided in Code Section 404(k)(2)(A)(iii) regarding the deductibility of dividends paid with respect to employer securities held by an employee stock ownership plan. Any modification or amendment of the Plan may be made retroactively, as necessary or appropriate, to meet any requirement of Code Section 404(k). The election provided under this Section is available only to the extent that the Company may deduct dividends paid with respect to Employer Securities held by the Employer Common Stock Fund under Code Section 404(k).

Section 6.07 QUALIFIED RESERVIST DISTRIBUTIONS. Any Participant who is a Qualified Reservist may withdraw the portion of his Account balance attributable to his own Before-Tax Contributions regardless of age or employment status to the extent that such distribution is a Qualified Reservist Distribution. For purposes of this Section 6.07, a "Qualified Reservist Distribution" is:

A. a distribution of Before-Tax Contributions;

B. made to a Participant who is a Qualified Reservist who (by reason of being a member of a reserve component (as defined in Section 101 of Title 37 of the United States Code)) was ordered or called to active duty for a period in excess of 179 days or for an indefinite period; and

C. made during the period beginning on the date of such order or call and ending at the close of the active duty period.

For purposes of this Section 6.07, a "Qualified Reservist" is an individual who is a reservist or national guardsman (as defined in Section 101(24) of Title 37 of the United States Code) ordered or called to active duty after September 11, 2001.

The following special rules apply to a Qualified Reservist Distribution:

D. Exception from the 10% Excise Tax for Early Withdrawals. A Qualified Reservist Distribution shall be exempt from the 10% excise tax under Code Section 72(t) for early withdrawals.

E. Qualified Reservist Distributions May Be Contributed to an IRA. The Participant who receives a Qualified Reservist Distribution may, at any time during the 2-year period beginning on the day after the end of the active duty period, make one or more contributions to an individual retirement account of such individual in an aggregate amount not to exceed the amount of such Qualified Reservist Distribution. The dollar limitations otherwise applicable to contributions to individual retirement accounts shall not apply to any contribution made pursuant to the preceding sentence; provided, however, that no deduction shall be allowed for any such contribution. In any event, the 2-year period referred to above for making re-contributions of Qualified Reservist Distributions shall not end before the date which is two years after August 17, 2006, the date of the enactment the Pension Protection Act of 2006 (i.e., shall not end prior to August 17, 2008). In no event shall the Participant be permitted to re-contribute a Qualified Reservist Distribution to this Plan.

ARTICLE VII
EMPLOYER ADMINISTRATIVE PROVISIONS

Section 7.01 ESTABLISHMENT OF TRUST. The Company shall execute a Trust Agreement, either within and as part of this Plan or as a separate agreement, with one or more persons or parties who shall serve as the Trustee. The Trustee so selected shall serve as the Trustee until otherwise replaced or said Trust agreement is terminated. The Company may, from time to time, enter into such further agreements with the Trustee or other parties and make such amendments to said Trust agreement as it may deem necessary or desirable to carry out this Plan. Any and all rights or benefits which may accrue to a person under this Plan shall be subject to all the terms and provisions of the Trust agreement.

Section 7.02 INFORMATION TO EMPLOYER AND COMMITTEE. Each Employer shall supply current information to the Committee as to the name, date of birth, date of employment, annual Compensation, leaves of absence, Years of Service, and date of termination of employment of each Employee who is, or who will be eligible to become, a Participant under the Plan, together with any other information that the Committee considers necessary. The Employer's records as to the current information that the Employer furnishes to the Committee shall be conclusive as to all persons.

Section 7.03 NO LIABILITY. The Employer assumes no obligation or responsibility to any of its Employees, Participants or Beneficiaries for any act of, or failure to act, on the part of any Committee, the Trustee or the Board (unless the Employer is the Plan's Administrator as defined in Section 3(16)(A) of ERISA).

Section 7.04 INDEMNITY OF PLAN ADMINISTRATOR AND COMMITTEE. Each Employer indemnifies and saves harmless the Plan Administrator and the members of the Committee, and each of them, from and against any and all loss (including reasonable attorneys' fees and costs of defense) resulting from liability to which the Plan Administrator, the Committee, or the members of a Committee, may be subjected by reason of any act or conduct (except willful misconduct or gross negligence) in their official capacities in the administration of this Plan and the Trust, including all expenses reasonably incurred in their defense, in case the Employer fails to provide such defense. The foregoing right of indemnification shall be in addition to such other rights as the Plan Administrator or any Committee member may enjoy as a matter of law or by reason of insurance coverage of any kind. Rights granted hereunder shall be in addition to and not in lieu of any rights to indemnification to which the Plan Administrator or any Committee member may be entitled pursuant to any liability insurance purchased or paid for by the Employer. The indemnification provisions of this Section 7.04 do not relieve the Plan Administrator or any Committee member from any liability he may have under ERISA for breach of a fiduciary duty to the extent such indemnification is prohibited by ERISA. Furthermore, the Plan Administrator and the Committee members and the Employer may execute an agreement further delineating the indemnification agreement of this Section 7.04, provided the agreement must be consistent with and shall not violate ERISA.

Section 7.05 INVESTMENT FUNDS. The Committee and the Trustee shall establish certain investment funds (the "Investment Funds"), rules governing the administration of the Investment Funds, and procedures for directing the investment of Participant Accounts among the Investment Funds. The Trustee shall invest and reinvest the principal and income of each Account in the Trust Fund as required by ERISA and as directed by Participants. The Committee and the Employer reserve the right to change the investment options available under the Plan and the rules governing investment designations at any time and from time to time.

Each Investment Fund (other than the Employer Common Stock Fund) shall be established by the Trustee at the direction or with the concurrence of the Committee. Investment Funds may, as so determined, consist of preferred and common stocks, bonds, debentures, negotiable instruments and evidences of indebtedness of every kind and form, or in securities and units of participation issued by companies registered under the Investment Companies Act of 1940, master limited partnerships or real estate investment trusts, or in any common or collective fund established or maintained for the collective investment and reinvestment of assets of pension and profit sharing trusts which are exempt from federal income taxation under the Code, or any combination of the foregoing. The Trustee shall hold, manage, administer, invest, reinvest, account for and otherwise deal with the Trust and each separate Investment Fund as provided in the Trust Agreement.

Section 7.06 CHESAPEAKE UTILITIES STOCK FUND. Notwithstanding the foregoing, the Trustee is specifically authorized to maintain the "Employer Common Stock Fund" (the Chesapeake Utilities Stock Fund) as the designated Investment Fund for Employer Matching Contributions (up to 100%) made under the Plan prior to January 1, 2011, and with respect to Employer Supplemental Contributions made after that date. The Employer Common Stock Fund is the portion of the Plan that is a stock bonus plan designated as an employee stock ownership plan or "ESOP" within the meaning of Code Section 4975(e)(7) and Section 407(d)(6) of ERISA. The Employer Common Stock Fund shall consist of stock of the Company and cash or cash equivalents needed to meet obligations of such fund or for the purchase of stock of the Company. One of the purposes of the Plan is to provide Participants with ownership interests in the Company through the purchase of common shares of the Company, and thus this ESOP portion of the Plan shall be permanently maintained and offered under the Plan. To the extent practicable, all available assets of the Employer Common Stock Fund shall be used to purchase Shares, which shall be held by the Trustee and allocated to Participant Accounts until distribution in kind or sale for distribution of cash to Participants or Beneficiaries or until disposition is required to implement changes in investment designations. The Trustee may acquire or dispose of Employer Securities as necessary to implement Participant directions and may net transactions within the Trust. In addition, when acquiring Employer Securities, the Trustee may acquire Employer Securities directly from the Company or on the open market as necessary to effect Participant directions. In either case, the price paid for such Employer Securities shall not exceed the fair market value of the Employer Securities. The fair market value of the Employer Securities acquired directly from the Company shall mean the mean between the high and low closing prices as reported by the New York Stock Exchange on the date of such transaction.

Anything in the Plan or Trust Agreement to the contrary notwithstanding, the Trustee shall not sell, alienate, encumber, pledge, transfer or otherwise dispose of, or tender or withdraw, any Employer Securities held by it under the Trust Agreement, except (A) as specifically provided for in the Plan or (B) in the case of a Tender Offer as directed in writing by a Participant (or Beneficiary, where applicable) on a form provided or approved by the Committee and delivered to the Trustee. For the purposes hereof, a "Tender Offer" shall mean any offer for, or request for or invitation for tenders of, or offer to purchase or acquire, any Shares that is directed generally to shareholders of the Employer or any transaction that may be defined as a Tender Offer under rules or regulations promulgated by the Securities and Exchange Commission. To the extent that any money or any other property is received by the Trustee as a result of a tender of Employer Securities not prohibited by the preceding sentence, such money or property shall be allocated to such other Investment Fund(s) as directed by the Employer. If a Participant fails to direct the Trustee as to whether or not to tender shares of Employer Securities, the Trustee shall tender or not tender such stock at the direction of the Committee, or to the extent not inconsistent with the foregoing provisions, such Employer Securities shall be voted in accordance with the terms of the Trust.

To the extent permitted by Treasury Regulations Section 54.4975-11(a)(4), the Plan may be amended retroactively to meet the requirements applicable to a stock bonus plan within the meaning of Code Section 401(a) and an employee stock ownership plan within the meaning of Code Section 4975(e).

ARTICLE VIII
PARTICIPANT ADMINISTRATIVE PROVISIONS

Section 8.01 PERSONAL DATA TO COMMITTEE. Each Participant and each Beneficiary of a deceased Participant must furnish to the Committee such evidence, data or information as the Committee considers necessary or desirable for the purpose of administering the Plan. The provisions of this Plan are effective for the benefit of each Participant upon the condition precedent that each Participant will furnish promptly full, true and complete evidence, data and information when requested by the Committee, provided the Committee shall advise each Participant of the effect of his failure to comply with its request. Any misstatement in the age, length of Service, date of employment, date of birth or Compensation of a Participant, Spouse, Beneficiary, or any other such matter, shall be corrected when it becomes known that any such misstatement of fact has occurred.

Section 8.02 ADDRESS FOR NOTIFICATION. Each Participant and each Beneficiary of a deceased Participant shall file with the Committee, from time to time, in writing, or otherwise notify the Committee (in accordance with its rules and procedures) of, his post office address and any change of post office address. Any communication, statement or notice addressed to a Participant, or Beneficiary, at his last post office address filed with the Committee, or as shown on the records of the Employer, shall bind the Participant, or Beneficiary, for all purposes of this Plan.

Section 8.03 ASSIGNMENT OR ALIENATION. Subject to Code Section 414(p) relating to qualified domestic relations orders, neither a Participant nor a Beneficiary shall anticipate, assign or alienate (either at law or in equity) any benefit provided under the Plan, and the Trustee shall not recognize any such anticipation, assignment or alienation. Furthermore, a benefit under the Plan is not subject to attachment, garnishment, levy, execution or other legal or equitable process, including the claims of any trustee in bankruptcy or other representative of the Participant or Beneficiary in such action.

Section 8.04 NOTICE OF CHANGE IN TERMS. The Employer, within the time prescribed by ERISA and the applicable regulations, shall furnish all Participants and Beneficiaries a summary description of any material amendment to the Plan or notice of discontinuance of the Plan and all other information required by ERISA to be furnished without charge.

Section 8.05 PARTICIPANT DIRECTION OF INVESTMENT. The Committee and the Trustee shall establish rules governing the administration of Investment Funds and procedures for Participant direction of investment, including rules governing the timing, frequency and manner of making investment elections. The Committee and the Employer reserve the right to change the investment options available under the Plan and rules governing investment designations from time to time. Nothing in this or any other provision of the Plan shall require the Trustee, the Employer or the Committee to implement Participant investment directions or changes in such directions, or to establish any procedures, other than on an administratively practicable basis, as determined by the Employer in its discretion.

Each Participant shall, in accordance with procedures established by the Committee and the Trustee, direct that his Account and contributions thereto be invested and reinvested in any one or more of the Investment Funds. The investment of any such monies shall be subject to such restrictions as the Committee may determine, in its sole discretion, to be advisable or necessary under the circumstances. Moreover, in accordance with procedures established by the Trustee and agreed to by the Committee, Participants may, when administratively practicable, be permitted to change their current and prospective investment designations through telephone, "on-line" or similar instructions to the Trustee or its authorized agent on a frequency established under such procedures, as in effect from time to time.

The exercise of investment direction by a Participant will not cause the Participant to be a fiduciary solely by reason of such exercise, and neither the Trustee nor any other fiduciary of this Plan will be liable for any loss or any breach that results from the exercise of investment direction by the Participant. The investment designation procedures established under the Plan shall be and are intended to be in compliance with the requirements of ERISA Section 404(c) and the regulations thereunder. Notwithstanding the foregoing, to the extent that a Participant or Beneficiary is entitled to direct the Trustee as to the investment of all or a portion of his Account among the Investment Funds available under the Plan, or as to the exercise of voting, tender or other rights appurtenant to the ownership of Employer Securities attributable to his Account, the Participant or Beneficiary shall be acting as a "named fiduciary" within the meaning of Section 403(a)(1) of ERISA; provided that, if by reason of the Participant's or Beneficiary's exercise of independent control over the assets in his Account, a particular transaction satisfies the requirements for relief under Section 404(c) of ERISA, the Participant or Beneficiary shall not be deemed a fiduciary, named or otherwise, with respect to such transaction and no other person who is otherwise a fiduciary shall be liable for any loss, or by reason of any breach, that results from the Participant's or Beneficiary's exercise of independent control pursuant to such transaction.

Notwithstanding any provision to the contrary, the Committee and the Trustee may, in their sole discretion and where the terms of any relevant investment contracts, regulated investment companies or pooled or group trusts so require, impose special terms, conditions and restrictions upon a Participant's right to direct the investment in, or transfer into or out of, such contracts, companies or trusts, or the timing or terms applicable to such transaction.

Section 8.06 CHANGE OF INVESTMENT DESIGNATIONS. Each Participant who is entitled to direct the investment of additional contributions to be allocated to his Account in accordance with Section 8.05 hereof may select how such additional contributions are to be invested. Such investment directions shall be made in accordance with applicable rules or procedures established by the Trustee and the Committee.

Each Participant may prospectively re-elect how those amounts then held in his Account are to be reinvested in the various Investment Funds until otherwise changed or modified. Such investment directions shall be made in accordance with applicable rules or procedures established by the Trustee and the Committee.

Notwithstanding the foregoing to the contrary, the Committee may, in its sole discretion and where the terms of any relevant investment contract, regulated investment companies or pooled or group trusts so require, or where ERISA fiduciary obligations and considerations so merit, impose special terms, conditions and restrictions upon a Participant's right to direct the investment in, or transfer into or out of, such contracts, companies or trusts.

Section 8.07 ESOP DIVERSIFICATION REQUIREMENTS. Any Qualified Participant may elect to transfer part of his interest in the Employer Common Stock Fund to one or more other investment funds offered under the Plan in accordance with this Section 8.07 and Code Section 401(a)(28). An election to make a transfer under this Section may be made only within 90 days after the close of each Plan Year in the Qualified Election Period. The amount eligible to be transferred under this Section following each Plan Year in the Qualified Election Period shall be determined as follows:

A. Except as otherwise provided in subsection B. below, the amount eligible to be transferred from the Employer Common Stock Fund to one or more other investment funds offered under the Plan shall be 25% of the value of the Participant's interest in the Employer Common Stock Fund, less any amount that has been transferred in accordance with a prior election under this Section.

B. Following the last Plan Year in the Qualified Election Period, the amount eligible to be transferred shall be 50% of the value of the Participant's interest in the Employer Common Stock Fund, less any amount that has been transferred in accordance with a prior election under this Section.

C. Notwithstanding any other provision of this Section, a Qualified Participant may not elect to transfer any amounts under this Section if the value of his interest in the Employer Common Stock Fund is a "de minimus" amount (as defined in regulations or other guidance issued by the Secretary of the Treasury).

D. Not later than 90 days after the end of each period during which an election may be made under this Section, the Plan shall transfer any amount that a Qualified Participant has elected to be transferred.

E. Definitions. For purposes of this Section 8.07, the following definitions shall apply:

(i) "Qualified Election Period" means the period described in Code Section 401(a)(28)(B)(iv).

(ii) "Qualified Participant" means any Participant who has completed at least ten years of participation under the Plan and has attained age 50.

Notwithstanding the foregoing, effective January 1, 2007, the following diversification requirements shall apply to the Employer Common Stock Fund:

F. Contributions Invested in Employer Common Stock Fund.

(i) An Applicable Individual (as defined below) may elect to divest any or all of the amounts contributed to his Account in the Plan prior to January 1, 2007, attributable to Matching Contributions and invested in the Employer Common Stock Fund, and reinvest an equivalent amount in other investment options available under the Plan meeting the requirements of subparagraph B. below. Such diversification shall be according to the following transition schedule:

Qualified Individual	% of Employer Stock Permitted to be Diversified
• Qualified Individual who has attained age 55 as of December 31, 2005	100%
• Qualified Individual who has not attained age 55	33% in 2007 66% in 2008 100% in 2009

(ii) An Applicable Individual may elect to divest any or all of the amounts contributed to his Account in the Plan on and after January 1, 2007, attributable to Matching Contributions and invested in the Employer Common Stock Fund, without further restriction.

G. Investment Options. The plan shall offer no less than three investment options, other than the Employer Common Stock Fund, to which the Applicable Individual may direct the proceeds from the divestment of the amounts in the Employer Common Stock Fund. Each such investment option shall be diversified and have materially different risk and return characteristics, subject to the available restrictions in subparagraph C. below.

H. Limitations on Divestiture of Employer Common Stock Fund. Any Applicable Individual may be limited for purposes of the divestment and reinvestment of amounts from the Employer Common Stock Fund to periodic, reasonable opportunities occurring at least quarterly. The Employer shall not otherwise impose any restrictions or conditions with respect to an Applicable Individual's right to divest investments in the Employer Common stock Fund which are not imposed on the investment of other assets in the Plan, except to the extent such restrictions or conditions are necessary to comply with applicable securities laws.

I. Applicable Individual. For purposes of this Section, "Applicable Individual," means (i) any Participant who has completed at least three years of Service; (ii) any alternate payee (of a Participant who has completed at least three years of Service) who has an Account under the Plan with respect to which the alternate payee is entitled to exercise the rights of a Participant; or (iii) a Beneficiary of a deceased Participant, who has an Account under the plan with respect to which the Beneficiary is entitled to exercise the rights of a Participant.

Section 8.08 LITIGATION AGAINST THE PLAN. If any legal action filed against the Trustee, the Employer as Plan Administrator, or any Committee, or against any member or members of any Committee, by or on behalf of any Participant or Beneficiary, results adversely to the Participant or to the Beneficiary, the Trustee shall reimburse itself, the Employer or any Committee, or any member or members of any Committee, all costs and fees expended by it or them by surcharging all costs and fees against the sums payable under the Plan to the Participant or to the Beneficiary, but only to the extent a court of competent jurisdiction specifically authorizes and directs any such surcharges and only to the extent Code Section 401(a)(13) does not prohibit any such surcharges.

Section 8.09 INFORMATION AVAILABLE. Any Participant in the Plan or any Beneficiary may, during reasonable business hours, examine copies of the Plan, the Trust, the Plan description, the latest annual report, any bargaining agreement, contract or any other instrument under which the Plan was established or is operated. The Company will maintain all of the items listed in this Section 8.08 in its offices, or in such other place or places as it may designate from time to time in order to comply with the regulations issued under ERISA. Upon the written request of a Participant or Beneficiary, the Committee shall furnish him with a copy of any item listed in this Section 8.08. The Committee may make a reasonable charge to the requesting person for the copy so furnished.

Section 8.10 APPEAL PROCEDURE FOR DENIAL OF BENEFITS. The Employer shall provide adequate notice in writing to any Participant or to any Beneficiary (the "Claimant") whose claim for benefits under the Plan has been denied. The Employer's notice to the Claimant shall set forth:

A. the specific reason for the denial;

B. specific references to pertinent Plan provisions on which the denial is based;

C. a description of any additional material and information needed for the Claimant to perfect his claim and an explanation of why the material or information is needed;

D. that any appeal the Claimant wishes to make of the adverse determination must be in writing to the Committee within 60 days after receipt of the notice of denial of benefits. The notice must further advise the Claimant that his failure to appeal the action to the Committee in writing within the 60-day period will render the determination final, binding and conclusive; and

E. an explanation that, if an adverse determination is made on review, the Claimant has the right to bring civil action under Section 502(a) of ERISA.

If the Claimant appeals to the Committee, he, or his duly authorized representative, may submit, in writing, whatever issues and comments he, or his duly authorized representative, feels are pertinent. The Claimant, or his duly authorized representative shall be provided, upon request and free of charge, reasonable access to and copies of all documents and other information relevant to the Claimant's claim for benefits. The Committee shall re-examine all facts related to the appeal and make a final determination as to whether the denial of benefits is justified under the circumstances. The Committee shall advise the Claimant of its decision within 60 days of the Claimant's written request for review, unless special circumstances (such as a hearing) would make the rendering of a decision within the 60-day limit unfeasible, but in no event shall the Committee render a decision respecting a denial for a claim for benefits later than 120 days after its receipt of a request for review. The Employer's notice of denial of benefits shall identify the address to which the Claimant may forward his appeal.

Section 8.11 CLAIMS INVOLVING BENEFITS RELATED TO DISABILITY. Notwithstanding the provisions of Section 8.10 of the Plan, the Committee shall comply with and follow the applicable Department of Labor Regulations for claims involving a determination of Disability or benefits related to Disability, including, but not limited to:

A. The Committee shall advise a Claimant of the Plan's adverse benefit determination within a reasonable period of time, but not later than 45 days after receipt of the claim by the Plan. If the Committee determines that due to matters beyond control of the Plan, such decision cannot be reached within 45 days, an additional 30 days may be provided and the Committee shall notify the Claimant of the extension prior to the end of the original 45-day period. The 30-day extension may be extended for a second 30-day period, if before the end of the original extension, the Committee determines that due to circumstances beyond the control of the Plan, a decision cannot be rendered within the extension period.

B. Claimants shall be provided at least 180 days following receipt of benefit denial in which to appeal such adverse determination.

C. The Committee shall review the Claimant's appeal and notify the Claimant of its determination within a reasonable period of time, but not later than 45 days after receipt of the Claimant's request for review. Should the Committee determine that special circumstances (such as the need to hold a hearing) require an extension of time for processing the appeal, the Committee shall notify the Claimant of the extension before the end of the initial 45 day period. Such an extension, if required, shall not exceed 45 days.

Section 8.12 USE OF ALTERNATIVE MEDIA. The Committee (or, in the absence of a Committee, the Plan Administrator) may include in any process or procedure for administering the Plan, the use of alternative media, including, but not limited to, telephonic, facsimile, computer or other such electronic means as available. Use of such alternative media shall be deemed to satisfy any Plan provision requiring a "written" document or an instrument to be signed "in writing" to the extent permissible under the Code, ERISA and applicable regulations.

Section 8.13 STATUTE OF LIMITATIONS FOR CIVIL ACTIONS. For purposes of filing any civil action against the Plan upon the exhaustion of all other available administrative remedies, including under ERISA Section 502(a), legal action may be brought no later than one year from the date of completion of the Plan's claims appeal process, or if earlier, one year from the date the Claimant knew or should have known that such claim existed.

ARTICLE IX
ADMINISTRATION OF THE PLAN

Section 9.01 ALLOCATION OF RESPONSIBILITY AMONG FIDUCIARIES FOR PLAN AND TRUST ADMINISTRATION. The fiduciaries shall have only those powers, duties, responsibilities and obligations as are specifically given to them under this Plan and the Trust. The Employers shall have the sole responsibility for making the contributions provided for under Article III of the Plan. The Company shall have the sole authority to appoint and remove the Trustee and members of any Committee, and to amend or terminate, in whole or in part, this Plan or the Trust; provided, however, that the Employer may delegate the authority to amend the Plan to the Committee, in its discretion. The Company shall have the final responsibility for the administration of the Plan, which responsibility is specifically described in this Plan and the Trust, and shall be the "Plan Administrator" and the named fiduciary. The Committee shall have the specific delegated powers and duties described in the further provisions of this Article IX and such further powers and duties as hereinafter may be delegated to them by the Employer. The Trustee shall have the sole responsibility for the administration of the Trust and the management of the assets held under the Trust, all as specifically provided in the Trust. Each fiduciary warrants that any directions given, information furnished, or action taken by it shall be in accordance with the provisions of this Plan and the Trust, authorizing or providing for such direction, information or action. Furthermore, each fiduciary may rely upon any such direction, information or action of another fiduciary as being proper under this Plan and the Trust, and is not required under this Plan or the Trust to inquire into the propriety of any such direction, information or action. It is intended under this Plan and the Trust that each fiduciary shall be responsible for the proper exercise of its own powers, duties, responsibilities and obligations under this Plan and the Trust and shall not be responsible for any act or failure to act of another fiduciary. No fiduciary guarantees the Trust Fund in any manner against investment loss or depreciation in asset value. The Trustee shall be responsible to ensure that contributions are made to the Trust only to the extent required by the terms of the Trust or applicable law.

Section 9.02 APPOINTMENT OF COMMITTEE. One or more committees consisting of at least two or more persons shall be appointed to assist in the administration of the Plan. In the event of any vacancies on any Committee, the remaining Committee member(s) then in office shall constitute the Committee and shall have full power to act and exercise all powers of the Committee as described in this Article IX. All usual and reasonable expenses of a Committee may be paid in whole or in part by the Employer, and any expenses not paid by the Employer shall be paid by the Trustee out of the principal or income of the Trust. Any members of the Committee who are Employees shall not receive compensation with respect to their services for the Committee.

In the event the Employer elects not to appoint a Committee, the Employer shall have such powers and duties as are allocated to the Committee under the Plan and any reference to the Committee shall be construed as a reference to the Employer.

Section 9.03 COMMITTEE PROCEDURES. A Committee may act at a meeting or in writing without a meeting. A Committee may elect one of its members as chairperson, appoint a secretary, who may or may not be a Committee member, and advise the Trustee of all relevant actions. The secretary shall keep a record of all meetings and forward all necessary communications to the Employer, or the Trustee, as appropriate. A Committee may adopt such bylaws and regulations as it deems desirable for the conduct of its affairs. All decisions of the Committee shall be made by the vote of the majority then in office, including actions in writing taken without a meeting. A dissenting Committee member who, within a reasonable time after he has knowledge of any action or failure to act by the majority, registers his dissent in writing delivered to the other Committee members, the Employer and the Trustee, shall not be responsible for any such action or failure to act.

Section 9.04 RECORDS AND REPORTS. The Employer (or any Committee if so designated by the Employer) shall exercise such authority and responsibility as it deems appropriate in order to comply with ERISA and any governmental regulations issued thereunder relating to records of a Participant's Service, Account balance(s) and the percentage of such Account balance(s) that are Nonforfeitable under the Plan, notifications to Participants, annual registration with the IRS, and annual reports to the Department of Labor.

Section 9.05 OTHER COMMITTEE POWERS AND DUTIES. The Committee(s) shall have one or more of the following powers and duties:

A. to determine the rights of eligibility of an Employee to participate in the Plan, the value of a Participant's Account, and the Nonforfeitable percentage of each Participant's Account, the rights of Beneficiaries to benefits under the Plan, and the method and time(s) of payment of benefits under the Plan, which such determination shall be final and conclusive;

B. to adopt rules of procedure and regulations necessary for the proper and efficient administration of the Plan, provided the rules are not inconsistent with the terms of this Plan and the Trust;

C. to construe and enforce the terms of the Plan and the rules and regulations it adopts, including the discretionary authority to interpret the Plan documents, documents related to the Plan's operation, and findings of fact;

D. to direct the Trustee with respect to the crediting and distribution of the Trust;

E. to review and render decisions respecting a claim for (or denial of a claim for) a benefit under the Plan;

F. to furnish the Employer with information that the Employer may require for tax or other purposes;

G. to engage the service of agents whom it may deem advisable to assist it with the performance of its duties;

H. to engage the services of an Investment Manager or Investment Managers (as defined in ERISA Section 3(38)), each of whom shall have full power and authority to manage, acquire or dispose (or direct the Trustee with respect to acquisition or disposition) of any Plan asset under its control, to remove any Investment Manager, and to appoint a successor if so desired; and

I. as permitted by the Employee Plans Compliance Resolution System ("EPCRS") issued by the Internal Revenue Service ("IRS"), as in effect from time to time, (i) to voluntarily correct any Plan qualification failure, including, but not limited to, failures involving Plan operation, impermissible discrimination in favor of Highly Compensated Employees, the specific terms of the Plan document, or demographic failures; (ii) implement any correction methodology permitted under EPCRS; and (iii) negotiate the terms of a compliance statement or a closing agreement proposed by the IRS with respect to correction of a Plan qualification failure.

Section 9.06 RULES AND DECISIONS. A Committee may adopt such rules as it deems necessary, desirable or appropriate. All rules and decisions of any Committee shall be uniformly and consistently applied to all Participants in similar circumstances. When making a determination or calculation, a Committee shall be entitled to rely upon information furnished by a Participant or Beneficiary, the Employer, the legal counsel of the Employer, or the Trustee.

Section 9.07 APPLICATION AND FORMS FOR BENEFITS. The Committee may require a Participant or Beneficiary to complete and file with the Committee and/or the Trustee an application for a benefit and all other forms approved by the Committee, and to furnish all pertinent information requested by the Committee and Trustee. The Committee and Trustee may rely upon all such information so furnished to it, including the Participant's or Beneficiary's current mailing address.

Section 9.08 AUTHORIZATION OF BENEFIT PAYMENTS. The Committee shall issue directions to the Trustee concerning all benefits that are to be paid from the Trust pursuant to the provisions of the Plan, or establish other procedures on which the Trustee may act, and warrants that all such directions are in accordance with this Plan.

Section 9.09 FUNDING POLICY. The Committee shall, from time to time, review all pertinent Employee information and Plan data in order to establish the funding policy of the Plan and to determine the appropriate methods of carrying out the Plan's objectives. The Committee or its delegate shall communicate periodically, as it deems appropriate, to the Trustee and to any Plan Investment Manager, the Plan's short-term and long-term financial needs so that investment policy can be coordinated with Plan financial requirements.

Section 9.10 FIDUCIARY DUTIES. In performing their duties, all fiduciaries with respect to the Plan shall act solely in the interest of the Participants and their Beneficiaries, and:

A. for the exclusive purpose of providing benefits to the Participants and their Beneficiaries;

B. with the care, skill, prudence and diligence under the circumstances then prevailing that a prudent man acting in like capacity and familiar with such matters would use in the conduct of an enterprise of like character and with like aims;

C. to the extent a fiduciary possesses and exercises investment responsibilities, by diversifying the investments of the Trust so as to minimize the risk of large losses, unless under the circumstances it is clearly prudent not to do so; and

D. in accordance with the documents and instruments governing the Plan insofar as such documents and instruments are consistent with the provisions of Title I of ERISA.

Section 9.11 ALLOCATION OR DELEGATION OF DUTIES AND RESPONSIBILITIES. In furtherance of their duties and responsibilities under the Plan, the Board or a designated Committee may, subject always to the requirements of Section 9.10 of the Plan:

A. employ agents to carry out nonfiduciary responsibilities;

B. employ agents to carry out fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA);

C. consult with counsel, who may be counsel to the Company; and

D. provide for the allocation of fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA) between the members of the Board, in the case of the Board, and among the members of any Committee, in the case of any Committee.

Section 9.12 PROCEDURE FOR THE ALLOCATION OR DELEGATION OF FIDUCIARY DUTIES. Any action described in subsections B. or D. of Section 9.11 of the Plan may be taken by a Committee or the Board only in accordance with the following procedure:

A. Such action shall be taken by a majority of the Committee or by the Board, as the case may be, in a resolution approved by a majority of such Committee or by a majority of the Board.

B. The vote cast by each member of the Committee or the Board for or against the adoption of such resolution shall be recorded and made a part of the written record of the Committee's or the Board's proceedings.

C. Any delegation of fiduciary responsibilities or any allocation of fiduciary responsibilities among members of the Committee or the Board may be modified or rescinded by the Committee or the Board according to the procedure set forth in subsections A. and B. of this Section 9.12.

Section 9.13 SEPARATE ACCOUNTING. The amounts in a Participant's Before-Tax, Catch-Up, Matching and (if applicable) his Qualified Matching Contribution Account and Qualified Non-elective Contribution Account shall at all times be separately accounted for from each other Account including a Participant's Supplemental Employer Contribution, Rollover, Transfer Account(s), and other contribution accounts, if any. Amounts credited to such subaccounts shall be allocated among the Participant's designated investments on a reasonable pro rata basis, in accordance with the valuation procedures of the Trustee and the Investment Funds. The Trustee and the Committee shall also establish uniform procedures which they may change from time to time, for the purpose of adjusting the subaccounts of a Participant's Account for withdrawals, loans, distributions and contributions. Gains, losses, withdrawals, distributions, and other credits or charges may be separately allocated among such subaccounts on a reasonable and consistent basis in accordance with such procedures.

Section 9.14 VALUE OF PARTICIPANT'S ACCOUNT. The value of each Participant's Account shall be based on its fair market value on the appropriate Valuation Date. A valuation shall occur at least once every Plan Year, and otherwise in accordance with the terms of the Trust and administratively practicable procedures approved by the Committee. Periodically, on a frequency determined by the Committee and the Trustee, the Participant will receive a statement showing the transaction activity and value of his Account as of a date set forth in the statement.

Section 9.15 INDIVIDUAL STATEMENT. As soon as practicable after the end of each calendar quarter, but within the time prescribed by ERISA and the regulations under ERISA, and at such other times as determined by the Committee in its discretion, the Committee will deliver to each Participant (and to each Beneficiary of a deceased Participant) a statement reflecting the condition of his Account(s) in the Trust as of that date and such other information ERISA requires be furnished the Participant or Beneficiary. In addition, subject to the requirements of ERISA, the Committee shall provide to any Participant or Beneficiary of a deceased Participant who so requests in writing, a statement indicating the total value of his Account(s) and the Nonforfeitable portion of such Account, if any. The Committee shall also furnish a written statement to any Participant who has a Severance from Employment during the Plan Year and is entitled to a deferred vested benefit under the Plan as of the end of the Plan Year, if no retirement benefits have been paid with respect to such Participant during the Plan Year. No Participant, except a member of the Committee, the Plan Administrator and their designees, shall have the right to inspect the records reflecting the Account of any other Participant. A Participant or Beneficiary shall notify the Committee or Trustee in writing if he believes there is an error in the statement of his Account in the Plan no more than one year after the date the statement was issued. Each statement of a Participant's Account shall be deemed to be final and binding on the Participant or Beneficiary to whom it was issued upon the expiration of the one year period following the date the statement was issued.

Section 9.16 REGISTRATION AND VOTING OF EMPLOYER COMMON STOCK. All Employer Securities acquired by the Trustee shall be held in the possession of the Trustee until disposed of pursuant to the provisions of the Plan or the Trust Agreement. Such Employer Securities may be registered in the name of the Trustee or its nominee. Before each annual or special meeting of the Employer's shareholders, the Trustee shall send to each Participant a copy of the proxy solicitation material therefor, together with a form requesting confidential instructions to the Trustee on how to vote the Employer Securities credited to his Account. Upon receipt of such instructions the Trustee shall vote the Employer Securities as instructed. Any Employer Securities held in Participants' Accounts, as to which the Trustee does not receive instructions, shall be voted as directed by the Committee, unless the Trustee determines that to do so is not prudent, or the Trust provides otherwise.

Section 9.17 FEES AND EXPENSES FROM FUND. The Trustee shall receive reasonable annual compensation as may be agreed upon from time to time between the Employer and the Trustee. The Trustee shall pay all expenses reasonably incurred by it or by the Employer, a Committee, or other professional advisers or administrators in the administration of the Plan from the Trust unless the Employer pays the expenses. The Committee shall not treat any fee or expense paid, directly or indirectly, by the Employer as an Employer contribution. No person who is receiving full pay from the Employer shall receive compensation for services from the Trust. Brokerage commissions, transfer taxes, and other charges and expenses in connection with the purchase and sale of securities shall be charged to each Investment Fund and/or Participant's Account, as applicable. Fees related to investments subject to Participant direction, and other fees resulting from or attributable to expenses incurred in relation to a Participant or Beneficiary or his Account may be charged to his Account to the extent permitted under the Code and ERISA.

ARTICLE X
TOP HEAVY RULES

Section 10.01 MINIMUM EMPLOYER CONTRIBUTION. If this Plan is Top Heavy, as defined below, in any Plan Year, the Plan guarantees a minimum contribution (subject to the provisions of this Article X) of 3% of Compensation for each Non-Key Employee, as defined below, who is a Participant employed by the Employer on the Accounting Date of the Plan Year without regard to Hours of Service completed during the Plan Year or to whether he has elected to make Before-Tax Contributions under Section 3.02A. of the Plan, and who is not a Participant in a Top Heavy defined benefit plan maintained by the Employer. Participants who also participate in a Top Heavy defined benefit plan of the Employer shall receive the required minimum benefit in this plan rather than the defined benefit plan. The Plan satisfies the guaranteed minimum contribution for the Non-Key Employee if the Non-Key Employee's contribution rate is at least equal to the minimum contribution. For purposes of this paragraph, a Non-Key Employee Participant includes any Employee otherwise eligible to participate in the Plan but who is not a Participant because his Compensation does not exceed a specified level.

If the contribution rate for the Key Employee, as defined below, with the highest contribution rate is less than 3%, the guaranteed minimum contribution for Non-Key Employees shall equal the highest contribution rate received by a Key Employee. The contribution rate is the sum of Employer contributions (not including Employer contributions to Social Security) and forfeitures allocated to the Participant's Account for the Plan Year divided by his Compensation, as defined below, not in excess of the compensation limitation under Code Section 401(a)(17) for the Plan Year. For purposes of determining the minimum contribution for a Plan Year, the Committee shall consider contributions made to any plan pursuant to a compensation reduction agreement or similar arrangement as Employer contributions. To determine the contribution rate, the Committee shall consider all qualified Top Heavy defined contribution plans maintained by the Employer as a single plan.

Notwithstanding the preceding provisions of this Section 10.01, if a defined benefit plan maintained by the Employer that benefits a Key Employee depends on this Plan to satisfy the anti-discrimination rules of Code Section 401(a)(4) or the coverage rules of Code Section 410 (or another plan benefiting the Key Employee so depends on such defined benefit plan), the guaranteed minimum contribution for a Non-Key Employee is 3% of his Compensation regardless of the contribution rate for the Key Employees.

The minimum Employer contribution required (to the extent required to be Nonforfeitable under Code Section 416(b)) may not be forfeited under Code Section 411(a)(3)(B) or 411(a)(3)(D).

Section 10.02 ADDITIONAL CONTRIBUTION. If the contribution rate (excluding Before-Tax Contributions) for the Plan Year with respect to a Non-Key Employee described in Section 10.01 of the Plan is less than the minimum contribution, the Employer will increase its contribution for such Employee to the extent necessary so his contribution rate for the Plan Year will equal the guaranteed minimum contribution. Matching Contributions will be taken into account to satisfy the minimum contribution requirement under the Plan, or if the Plan provides that the minimum contribution requirement shall be met in another plan, such other plan.

Matching Contributions that are used to satisfy the minimum contribution requirements shall be treated as matching contributions for purposes of the actual contribution percentage test and other requirements of Code Section 401(m). The additional contribution shall be allocated to the Account of a Non-Key Employee for whom the Employer makes the contribution.

Section 10.03 DETERMINATION OF TOP HEAVY STATUS. The Plan is "Top Heavy" for a Plan Year if the Top Heavy ratio as of the Determination Date exceeds 60%. The Top Heavy ratio is a fraction, the numerator of which is the sum of the present value of the Accounts of all Key Employees as of the Determination Date, and the denominator of which is a similar sum determined for all Employees. For purposes of determining the present value of the Accounts for the foregoing fraction, contributions due as of the Determination Date and distributions made for any purpose within the one-year period ending on the Determination Date shall be included. In addition, distributions made within the five-year period ending on the Determination Date shall be included if such distributions were made for reasons other than upon Severance from Employment, death or Disability (e.g., in-service withdrawals); provided, however, that no distribution shall be counted more than once. In addition, the Top Heavy ratio shall be calculated by disregarding the Account (including distributions, if any, of the Account balance) of an individual who has not received credit for at least one Hour of Service with the Employer during the one-year period ending on the Determination Date in such calculation. The Top Heavy ratio, including the extent to which it must take into account distributions, rollovers, and transfers, shall be calculated in accordance with Code Section 416 and the Treasury Regulations thereunder.

If the Employer maintains other qualified plans (including a simplified employee pension plan), this Plan is Top Heavy only if it is part of the Required Aggregation Group, and the Top Heavy ratio for both the Required Aggregation Group and the Permissive Aggregation Group exceeds 60%. The Top Heavy ratio shall be calculated in the same manner as required by the first paragraph of this Section 10.03, taking into account all plans within the Aggregation Group. To the extent distributions to a Participant must be taken into account, the Committee shall include distributions from a terminated plan that would have been part of the Required Aggregation Group if it were in existence on the Determination Date. The present value of accrued benefits and the other amounts the Committee must take into account, under defined benefit plans or simplified employee pension plans included within the group, shall be calculated in accordance with the terms of those plans, Code Section 416 and the Treasury Regulations thereunder. If an aggregated plan does not have a valuation date coinciding with the Determination Date, the accrued benefits or Accounts in the aggregated plan shall be valued as of the most recent valuation date falling within the 12-month period ending on the Determination Date. The Top Heavy ratio shall be valued with reference to the Determination Dates that fall within the same calendar year.

The accrued benefit of a Participant other than a Key Employee shall be determined under (a) the method, if any, that uniformly applies for accrual purposes under all defined benefit plans maintained by the Employer, or (b) if there is no such method, as if such benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional rule of Code Section 411(b)(1)(C).

Section 10.04 DEFINITIONS. For purposes of applying the provisions of this Article X.

A. "Key Employee" means any Employee or former Employee (including any deceased Employee) who at any time during the Plan Year that includes the Determination Date was an officer of the Employer having annual Compensation greater than $130,000 (as adjusted under Code Section 416(i)(1) for Plan Years beginning after December 31, 2002), a Five-percent Owner of the Employer, or a one-percent owner of the Employer having annual Compensation of more than $150,000. The constructive ownership rules of Code Section 318 (or the principles of that section, in the case of an unincorporated Employer) will apply to determine ownership in the Employer. The determination of who is a Key Employee shall be made in accordance with Code Section 416(i)(1) and the Treasury Regulations under that Code Section.

B. "Non-Key Employee" means an Employee who does not meet the definition of Key Employee.

C. "Compensation" means the first $200,000 (or such larger amount as the Commissioner of Internal Revenue may prescribe in accordance with Code Section 401(a)(17)) of Compensation as defined in Code Section 415(c)(3), but including amounts contributed by the Employer pursuant to a salary reduction agreement that are excludible from the Employee's gross income under Code Section 125, "deemed compensation" under Code Section 125 pursuant to Revenue Ruling 2002-27, Code Sections 132(f)(4), 402(a)(8), 402(h) or 403(b).

D. "Required Aggregation Group" means:

(i) each qualified plan of the Employer in which at least one Key Employee participates at any time during the five Plan Year period ending on the Determination Date; and

(ii) any other qualified plan of the Employer that enables a plan described in (i) to meet the requirements of Code Section 401(a)(4) or 410.

The Required Aggregation Group includes any plan of the Employer that was maintained within the last five years ending on the Determination Date on which a top heaviness determination is being made if such plan would otherwise be part of the Required Aggregation Group for the Plan Year but for the fact it has been terminated.

E. "Permissive Aggregation Group" means the Required Aggregation Group plus any other qualified plans maintained by the Employer, but only if such group would satisfy in the aggregate the requirements of Code Sections 401(a)(4) and 410. The Committee shall determine which plans to take into account in determining the Permissive Aggregation Group.

F. "Employer" means all the members of a controlled group of corporations (as defined in Code Section 414(b)), of a commonly controlled group of trades or businesses (whether or not incorporated) (as defined in Code Section 414(c)), or an affiliated service group (as defined in Code Section 414(m)), of which the Employer is a part. However, ownership interests in more than one member of a related group shall not be aggregated to determine whether an individual is a Key Employee because of his ownership interest in the Employer.

G. "Determination Date" means, for any Plan Year, the Accounting Date of the preceding Plan Year or, in the case of the first Plan Year of the Plan, the Accounting Date of that Plan Year.

ARTICLE XI
MISCELLANEOUS

Section 11.01 EVIDENCE. Anyone required to give evidence under the terms of the Plan may do so by certificate, affidavit, document or other information that the person to act in reliance may consider pertinent, reliable and genuine, and to have been signed, made or presented by the proper party or parties. The Employer, any Committee and the Trustee shall be fully protected in acting and relying upon any evidence described under the immediately preceding sentence.

Section 11.02 NO RESPONSIBILITY FOR EMPLOYER ACTION. Neither the Trustee nor any Committee shall have any obligation or responsibility with respect to any action required by the Plan to be taken by the Employer, any Participant or eligible Employee, nor for the failure of any of the above persons to act or make any payment or contribution, or otherwise to provide any benefit contemplated under this Plan, nor shall the Trustee or any Committee be required to collect any contribution required under the Plan (unless otherwise provided herein), or determine the correctness of the amount of any Employer contribution. Neither the Trustee nor any Committee need inquire into or be responsible for any action or failure to act on the part of the others, or on the part of any other person who has any responsibility regarding the management, administration or operation of the Plan, whether by the express terms of the Plan or by a separate agreement authorized by the Plan or by the applicable provisions of ERISA. Any action required of a corporate Employer shall be by its Board, by the Compensation Committee of the Board, or by its designee.

Section 11.03 FIDUCIARIES NOT INSURERS. The Trustee, the Committee(s), the Plan Administrator and the Employer in no way guarantee the Trust from loss or depreciation. The Employer does not guarantee the payment of any money that may be or becomes due to any person from the Trust. The liability of any Committee and the Trustee to make any payment from the Trust at any time and all times is limited to the then available assets of the Trust.

Section 11.04 WAIVER OF NOTICE. Any person entitled to notice under the Plan may waive the notice, unless the Code or Treasury Regulations issued thereunder require the notice, or ERISA specifically or impliedly prohibits such a waiver.

Section 11.05 SUCCESSORS. The Plan shall be binding upon all persons entitled to benefits under the Plan, their respective heirs and legal representatives, upon the Employer, its successors and assigns, and upon the Trustee, any Committee, the Plan Administrator and their successors.

Section 11.06 WORD USAGE. Words used in the masculine also apply to the feminine or neuter where applicable, and wherever the context of the Plan dictates, the plural includes the singular and the singular includes the plural.

Section 11.07 HEADINGS. The headings are for reference only. In the event of a conflict between a heading and the content of a Section, the content of the Section shall control.

Section 11.08 STATE LAW. Delaware law shall determine all questions arising with respect to the provisions of this agreement except to the extent a federal statute supersedes Delaware law.

Section 11.09 EMPLOYMENT NOT GUARANTEED. Nothing contained in this Plan, and nothing with respect to the establishment of the Trust, any modification or amendment to the Plan or the Trust, the creation of any Account, or the payment of any benefit, shall give any Employee, Employee-Participant or Beneficiary any right to continue employment, or any legal or equitable right against the Employer, an Employee of the Employer, the Trustee, the Committee, the Plan Administrator, or agents or employees of such individuals or entities. Nothing in the Plan shall be deemed or construed to impair or affect in any manner the right of the Employer, in its discretion, to hire Employees and, with or without cause, to discharge or terminate the service of Employees.

ARTICLE XII
EXCLUSIVE BENEFIT, AMENDMENT, TERMINATION

Section 12.01 EXCLUSIVE BENEFIT. Except as provided herein, the Employer shall have no beneficial interest in any asset of the Trust and no part of any asset in the Trust shall ever revert to or be repaid to the Employer, either directly or indirectly; nor prior to the satisfaction of all liabilities with respect to the Participants and their Beneficiaries under the Plan, shall any part of the corpus or income of the Trust, or any asset of the Trust, be (at any time) used for, or diverted to, purposes other than the exclusive benefit of the Participants or their Beneficiaries.

Section 12.02 AMENDMENT BY EMPLOYER. The Company shall have the right at any time and from time to time:

A. to amend this agreement in any manner it deems necessary or advisable in order to qualify (or maintain qualification of) this Plan and the Trust created under it under the appropriate provisions of the Code; and

B. to amend this agreement in any other manner.

However, no amendment shall authorize or permit any part of the Trust (other than the part required to pay taxes and administration expenses) to be used for or diverted to purposes other than for the exclusive benefit of the Participants or their Beneficiaries or estates. No amendment shall cause or permit any portion of the Trust to revert to or become a property of the Employer; and the Company shall not make any amendment that affects the rights, duties or responsibilities of the Plan Administrator or any Committee without the written consent of the affected Plan Administrator or the affected member of such Committee. Furthermore, no amendment shall decrease a Participant's Account balance or accrued benefit or reduce or eliminate any benefits protected under Code Section 411(d)(6) with respect to a Participant with an Account balance or accrued benefit at the date of the amendment, except to the extent permitted under Code Section 412(c)(8).

The Company shall make all amendments in writing. Amendments shall be considered properly authorized by the Company if approved or ratified by the Board, any committee of the Board, or by an authorized committee of the Plan, unless the subject of the amendment has been reserved to the Board or another authorized party. Each amendment shall state the date to which it is either retroactively or prospectively effective, and may be executed by the Committee or any authorized officer of the Company. No amendment to the Plan shall require execution by the Trustee unless the amendment affects the rights or duties of the Trustee under Article XIII of this Plan.

Section 12.03 AMENDMENT TO VESTING PROVISIONS. Although the Company reserves the right to amend the vesting provisions at any time, an amended vesting schedule shall not be applied to reduce the Nonforfeitable percentage of any Participant's Account derived from Employer contributions (determined as of the later of the date the Company adopts the amendment, or the date the amendment becomes effective) to a percentage less than the Nonforfeitable percentage computed under the Plan without regard to the amendment. An amended vesting schedule will apply to a Participant only if the Participant receives credit for at least one Hour of Service after the new schedule becomes effective.

If the Company makes a permissible amendment to the vesting provisions, each Participant having at least three Years of Service for vesting purposes with the Employer may elect to have the percentage of his Nonforfeitable Account Balance computed under the Plan without regard to the amendment. The Participant must file his election with the Employer within 60 days of the latest of (a) the Company's adoption of the amendment; (b) the effective date of the amendment; or (c) his receipt of a copy of the amendment. The authorized Committee, as soon as practicable, shall forward a true copy of any amendment to the vesting schedule to each affected Participant, together with an explanation of the effect of the amendment, the appropriate form upon which the Participant may make an election to remain under the vesting schedule provided under the Plan prior to the amendment and notice of the time within which the Participant must make an election to remain under the prior vesting schedule. The election described in this Section 12.03 does not apply to a Participant if the amended vesting schedule provides for vesting that is at least as rapid at all times as the vesting schedule in effect prior to the amendment. For purposes of this Section 12.03, an amendment to the vesting schedule includes any amendment that directly or indirectly affects the computation of the Nonforfeitable percentage of an Employee's rights to his Employer-derived Account.

Section 12.04 DISCONTINUANCE. The Employer shall have the right, at any time, to suspend or discontinue its contributions under the Plan, and the Company (acting through the Committee) shall have the right to terminate, at any time, this Plan and the Trust created under this agreement. The Plan shall terminate upon the first to occur of the following:

A. the date terminated by action of the Company;

B. the date the Employer shall be judicially declared bankrupt or insolvent; or

C. the dissolution, merger, consolidation or reorganization of the Employer or the sale by the Employer of all or substantially all of its assets, unless the successor or purchaser makes provision to continue the Plan, in which event the successor or purchaser shall substitute itself as the Employer under this Plan.

Section 12.05 FULL VESTING ON TERMINATION. Notwithstanding any other provision of this Plan to the contrary, upon either full or partial termination of the Plan, or, if applicable, upon the date of complete discontinuance of contributions to the Plan, an affected Participant's right to his Account shall be 100% Nonforfeitable.

Section 12.06 MERGER, DIRECT TRANSFER AND ELECTIVE TRANSFER. The Trustee shall not consent to, or be a party to, any merger or consolidation with another plan, or to a transfer of assets or liabilities to another plan, unless immediately after the merger, consolidation or transfer, the surviving plan provides each Participant a benefit equal to or greater than the benefit each Participant would have received had the Plan terminated immediately before the merger or consolidation or transfer. The Trustee possesses the specific authority to enter into merger agreements or direct transfer of assets agreements with the trustees of other retirement plans described in Code Section 401(a) and to accept the direct transfer of plan assets, or to transfer plan assets, as a party to any such agreement, only upon the consent or direction of the Committee.

If permitted by the Committee in its discretion, the Trustee may accept a direct transfer of plan assets on behalf of an Employee prior to the date the Employee satisfies the Plan's eligibility condition(s). If the Trustee accepts such a direct transfer of plan assets, the Employee shall be treated as a Participant for all purposes of the Plan except that the Employee shall not share in Employer contributions or Participant forfeitures under the Plan until he actually becomes a Participant in the Plan. The Trustee shall hold, administer and distribute the transferred assets as a part of the Trust, and the Trustee shall maintain a separate Transfer Account for the benefit of the Employee on whose behalf the Trustee accepted the transfer in order to reflect the value of the transferred assets.

The Trustee may not consent to, or be a party to, a merger, consolidation or transfer of assets with a defined benefit plan, except with respect to an elective transfer, unless the Committee consents and so directs, and the transfer is consistent with the Code and with ERISA. The Trustee will hold, administer and distribute the transferred assets as a part of the Trust, and the Trustee shall maintain a separate Transfer Account for the benefit of the Employee on whose behalf the Trustee accepted the transfer in order to reflect the value of the transferred assets. Unless a transfer of assets to this Plan is an elective transfer, the Plan will preserve all Code Section 411(d)(6) protected benefits with respect to those transferred assets, in the manner described in Section 12.02.

A transfer is an elective transfer if: (a) the transfer satisfies the first paragraph of this Section 12.06; (b) the transfer is voluntary, under a fully informed election by the Participant; (c) the Participant has an alternative that retains his Code Section 411(d)(6) protected benefits (including an option to leave his benefit in the transferor plan, if that plan is not terminating); (d) the transfer satisfies the applicable spousal consent requirements of the Code; (e) the transferor plan satisfies the joint and survivor notice requirements of the Code, if the Participant's transferred benefit is subject to those requirements; (f) the Participant has a right to immediate distribution from the transferor plan, in lieu of the elective transfer; (g) the transferred benefit is at least the greater of the single sum distribution provided by the transferor plan for which the Participant is eligible or the present value of the Participant's accrued benefit under the transferor plan payable at that plan's normal retirement age; (h) the Participant has a 100% Nonforfeitable interest in the transferred benefit; and (i) the transfer otherwise satisfies applicable Treasury Regulations. An elective transfer may occur between qualified plans of any type.

If the Plan receives a direct transfer (by merger or otherwise) of elective contributions (or amounts treated as elective contributions) under a plan with a Code Section 401(k) arrangement, the distribution restrictions continue to apply to those transferred elective contributions.

Section 12.07 TERMINATION. Upon termination of the Plan, the distribution provisions of Article IV and Article V shall remain operative, except that:

A. If the present value of the Participant's Nonforfeitable Account does not exceed \$1,000 (\$5,000 prior to March 28, 2005), the Committee will direct the Trustee to distribute to the Participant the Participant's Nonforfeitable Account to him in a lump sum as soon as administratively practicable after the Plan terminates; and

B. If the present value of the Participant's Nonforfeitable Account exceeds $1,000 ($5,000 prior to March 28, 2005), the Participant or the Beneficiary, in addition to the distribution events permitted under Articles IV and V, may elect to have the Trustee commence distribution of his Nonforfeitable Account as soon as administratively practicable after the Plan terminates.

The Trust shall continue until the Trustee, after written direction from the Committee, has distributed all of the benefits under the Plan. To liquidate the Trust, the Committee will, to the extent required, purchase a deferred annuity contract for each Participant that protects the Participant's distribution rights under the Plan, if the Participant's Nonforfeitable Account exceeds $1,000 ($5,000 prior to March 28, 2005), and the Participant does not elect an immediate distribution pursuant to this Section 12.07. Upon termination of the Plan, the amount, if any, in a suspense account under Article IV of the Plan shall revert to the Employer, subject to the conditions of the Treasury Regulations permitting such a reversion.

ARTICLE XIII
TRUSTEE POWERS AND DUTIES

Section 13.01 ACCEPTANCE. The Trustee accepts the Trust created under the Plan and agrees to perform the obligations imposed. The Trustee shall provide bond for the faithful performance of its duties under the Trust to the extent required by ERISA.

Section 13.02 RECEIPT OF CONTRIBUTIONS. The Trustee shall be accountable to the Company for the funds contributed to it by the Company, but shall have no duty to see that the contributions received comply with the provisions of the Plan. The Trustee shall be neither obliged to collect any contributions from the Company, nor to see that funds deposited with it are deposited according to the provisions of the Plan.

Section 13.03 FULL INVESTMENT POWERS. The Trustee shall have full discretion and authority with regard to the investment of the Trust, except with respect to a Plan asset under the control or direction of a properly appointed Investment Manager, or with respect to a Plan asset subject to Company or Committee direction of investment. The Trustee shall coordinate its investment policy with Plan financial needs as communicated to it by the Committee. The Trustee is authorized and empowered, but not by way of limitation, with the following powers, rights and duties:

A. to invest any part or all of the Trust in any common or preferred stocks, open-end or closed-end mutual funds, put and call options traded on a national exchange, United States retirement bonds, corporate bonds, debentures, convertible debentures, commercial paper, U.S. Treasury bills, U.S. Treasury notes and other direct or indirect obligations of the United States Government or its agencies, improved or unimproved real estate situated in the United States, limited partnerships, insurance contracts, mortgages, notes or other property of any kind, real or personal, and to buy or sell options on common stock on a nationally recognized options exchange with or without holding the underlying common stock, as a prudent man would do under like circumstances with due regard for the purposes of this Plan. Any investment made or retained by the Trustee in good faith shall be proper but must be of a kind constituting a diversification considered by law suitable for trust investments;

B. to retain in cash so much of the Trust as it may deem advisable to satisfy liquidity needs of the Plan and to deposit any cash held in the Trust in a bank account at reasonable interest, including, if a bank is acting as Trustee, specific authority to invest in any type of deposit of the Trustee or in a collective trust fund (the provisions of which, as the same shall from time to time be amended, altered, or supplemented, govern the investment of such assets and which the Plan incorporates by this reference) as described in Code Section 584 that the Trustee maintains exclusively for the collective investment of money contributed by such bank or trust company in its capacity as a Trustee for employee benefits trusts, and which conforms to the rules of the Comptroller of the Currency;

C. to manage, sell, contract to sell, grant options to purchase, convey, exchange, transfer, abandon, improve, repair, insure, lease for any term even though commencing in the future or extending beyond the term of the Trust, and otherwise deal with all property, real or personal, in such manner, for such considerations and on such terms and conditions as the Trustee shall decide;

D. to credit and distribute the Trust as directed by the Committee. The Trustee shall not be obliged to inquire as to whether any payee or distributee is entitled to any payment or whether the distribution is proper or within the terms of the Plan, or as to the manner of making any payment or distribution. The Trustee shall be accountable only to the Committee for any payment or distribution made by it in good faith on the order or direction of the Committee;

E. to borrow money, to assume indebtedness, extend mortgages and encumber by mortgage or pledge;

F. to compromise, contest, arbitrate or abandon claims and demands, in its discretion;

G. to have with respect to the Trust all of the rights of an individual owner, including the power to give proxies, to participate in any voting trusts, mergers, consolidations or liquidations, and to exercise or sell stock subscriptions or conversion rights;

H. to lease for oil, gas and other mineral purposes and to create mineral severances by grant or reservation; to pool or unitize interests in oil, gas and other minerals; and to enter into operating agreements and to execute division and transfer orders;

I. to hold any securities or other property in the name of the Trustee or its nominee, or in another form as it may deem best, with or without disclosing the trust relationship;

J. to perform any and all other acts in its judgment necessary or appropriate for the proper and advantageous management, investment and distribution of the Trust;

K. to retain any funds or property subject to any dispute without liability of the payment of interest, and to decline, when reasonable to do so, to make payment or delivery of the funds or property until final adjudication is made by a court of competent jurisdiction;

L. to furnish all Schedule Ps, 1099-Rs, W2-Ps and all other tax returns or portions thereof required of the Trustee;

M. to furnish to the Company, the Plan Administrator and the Committee statements of account at least annually showing the condition of the Trust and all investments, receipts, disbursements and other transactions effected by the Trustee during the Plan Year covered by the statement and also stating the assets of the Trust held at the end of the Plan Year. The Committee may approve an accounting by written notice of approval delivered to the Trustee in writing within 90 days from the date upon which the account statement was mailed or otherwise delivered to the Committee. The Committee agrees to use its best efforts to review account statements provided by the

Trustee within 90 days from the date the account statement was mailed or delivered to the Committee. Any matters objected to by the Committee shall be communicated to the Trustee in a writing signed by a member of the Committee, and the Trustee shall be given a reasonable opportunity to explain or adjust such matters; and

N. to begin, maintain, or defend any litigation necessary in connection with the administration of the Plan, except that the Trustee shall not be obliged or required to do so unless indemnified to its satisfaction.

Section 13.04 RECORDS AND STATEMENTS. The records of the Trustee pertaining to the Plan shall be open to the inspection of the Plan Administrator, the Committee and the Company at all reasonable times and may be audited from time to time by any person or persons as the Company or Committee may specify in writing. The Trustee shall furnish the Committee or the Plan Administrator with whatever information relating to the Trust the Committee or Plan Administrator considers necessary. However, the Trustee is not authorized to disclose the name, address, and security position(s) of current and/or future security holdings that the Trust may own from time to time pursuant to SEC Rule #14b-1(c).

Section 13.05 FEES AND EXPENSES FROM FUND. The Trustee shall receive reasonable annual compensation as may be agreed upon from time to time between the Company and the Trustee. The Trustee shall pay all expenses reasonably incurred by it or by the Company, the Committee, or other professional advisers or administrators in the administration of the Plan from the Trust unless the Company pays the expenses. The Committee shall not treat any fee or expense paid, directly or indirectly, by the Company as a Company contribution. No person who is receiving full pay from the Company shall receive compensation for services from the Trust.

Section 13.06 DISTRIBUTION OF CASH OR PROPERTY. The Trustee may make distribution under the Plan in cash or property, or partly in each, at its fair market value as determined by the Trustee. For purposes of a distribution to a Participant or to a Participant's designated Beneficiary or surviving Spouse, "property" shall include a nontransferable annuity contract or Employer Securities.

Section 13.07 DISTRIBUTION DIRECTIONS. If no one claims a payment or distribution made from the Trust, the Trustee shall promptly notify the Committee and shall dispose of the payment in accordance with the subsequent direction of the Committee.

Section 13.08 THIRD PARTY. No person dealing with the Trustee shall be obligated to see to the proper application of any money paid or property delivered to the Trustee, or to inquire whether the Trustee has acted pursuant to any of the terms of the Plan. Each person dealing with the Trustee may act upon any notice, request or representation in writing by the Trustee, or by the Trustee's duly authorized agent, and shall not be liable to any person whomsoever in so doing. The certificate of the Trustee that it is acting in accordance with the Plan shall be conclusive in favor of any person relying on the certificate.

If more than one person or entity is acting as Trustee, the decision of a majority of the Trustee(s) shall control with respect to any decision regarding the administration or investment of the Trust.

Section 13.09 RESIGNATION. The Trustee may resign at any time as Trustee of the Plan by giving 30 days' written notice in advance to the Company and to the Committee.

Section 13.10 REMOVAL. The Company, by giving 30 days' written notice in advance to the Trustee, may remove any Trustee.

Section 13.11 INTERIM DUTIES AND SUCCESSOR TRUSTEE. In the event of the resignation or removal of a Trustee, the Company shall appoint a successor Trustee if it intends to continue the Plan. During any period the selection of a Trustee is pending, or during any period a Trustee is unable to serve for any reason, the remaining Trustee or Trustee(s), if any, shall act as the sole Trustee or as the only Trustee(s) of the Trust created under this Agreement. If no Trustee remains during any period the selection of a Trustee is pending, the Company shall act as Trustee until a successor Trustee is selected.

Each successor Trustee shall succeed to the title to the Trust vested in his predecessor by accepting in writing his appointment as successor Trustee and filing the acceptance with the former Trustee and the Committee without the signing or filing of any further statement. The resigning or removed Trustee, upon receipt of acceptance in writing of the Trust by the successor Trustee, shall execute all documents and do all acts necessary to vest the title of record in any successor Trustee. Each successor Trustee shall have and enjoy all of the powers, both discretionary and ministerial, conferred under this Agreement upon his predecessor. No successor Trustee shall be personally liable for any act or failure to act of any predecessor Trustee. With the approval of the Company and the Committee, a successor Trustee, with respect to the Plan, may accept the account rendered and the property delivered to it by a predecessor Trustee without incurring any liability or responsibility for so doing.

Section 13.12 VALUATION OF TRUST. The Trustee shall value the Trust as of each Accounting Date to determine the fair market value of the Trust assets, and the Trustee shall value the Trust on such other date(s) as directed by the Committee.

Section 13.13 LIMITATION ON LIABILITY - IF INVESTMENT MANAGER APPOINTED. The Trustee shall not be liable for the acts or omissions of any Investment Manager or Managers the Company or Committee may appoint, nor shall the Trustee be under any obligation to invest or otherwise manage any asset of the Plan that is subject to the management of a properly appointed Investment Manager. The Committee, the Trustee and any properly appointed Investment Manager may execute a letter agreement as a part of this Plan delineating the duties, responsibilities and liabilities of the Investment Manager.

Section 13.14 INVESTMENT IN GROUP TRUST. The Trustee, for collective investment purposes, may combine into one trust fund the Trust created under this Plan with the Trust created under any other qualified retirement plan the Company or any Related Employers maintain. However, the Trustee shall maintain separate records of account for each Trust in order to reflect properly the assets allocable to each plan.

Section 13.15 TRUST FOR EXCLUSIVE BENEFIT OF PARTICIPANTS OF THE PLAN AND THEIR BENEFICIARIES. Except as otherwise provided in Sections 3.13 and 12.07, it shall be impossible under any circumstances at any time for any part of the corpus or income of the Trust to be used for, or diverted to, purposes other than for the exclusive benefit of Participants and their Beneficiaries.

The Company has executed this amended and restated Plan on the date set forth below.

CHESAPEAKE UTILITIES CORPORATION

By: ______________________________

Title: ______________________________

Date: ______________________________

SCHEDULE I
LIMITATIONS ON CONTRIBUTIONS AND ALLOCATIONS

Section I.01 LIMITATIONS APPLICABLE TO BEFORE-TAX CONTRIBUTIONS.

A. **Definitions**. For purposes of this Schedule, the following definitions shall apply:

(i) "Actual Deferral Percentage," for each Plan Year, means the average of the ratios (calculated separately for each Participant in a specified group) of:

1. the amount of Before-Tax Contributions actually paid over to the Trust on behalf of each such Participant for such Plan Year, including Excess Before-Tax Contributions, but excluding: (a) Before-Tax Contributions that are taken into account in the Contribution Percentage test (provided the Actual Deferral Percentage test is satisfied both with and without exclusion of these Before-Tax Contributions), (b) Catch-Up Contributions, and (c) Before-Tax Contributions made pursuant to Code Section 414(u) by reason of qualified military service, to

2. the Participant's Compensation for such Plan Year for the period during which he was a Participant in the Plan.

For purposes of computing Actual Deferral Percentages, an Eligible Employee who would be a Participant but for the failure to make Before-Tax Contributions shall be treated as a Participant on whose behalf no Before-Tax Contributions are made.

(ii) "Excess Before-Tax Contributions," with respect to any Plan Year, means the excess of:

1. The aggregate amount of Employer contributions actually taken into account in computing the Actual Deferral Percentage of Highly Compensated Employees for such Plan Year, over

2. The maximum amount of such contributions permitted by the Actual Deferral Percentage test (determined by reducing contributions made on behalf of Highly Compensated Employees in order of their Actual Deferral Percentages, beginning with the highest of such percentages).

B. **Actual Deferral Percentage Test**. In any Plan Year in which the Actual Deferral Percentage for the group of Highly Compensated Employees, taking into account Employee elections, would be more than the greater of:

(i) the Actual Deferral Percentage for the group of Non-Highly Compensated Employees for the current Plan Year, multiplied by 1.25, or

(ii) the lesser of 2% plus the Actual Deferral Percentage for the group of Non-Highly Compensated Employees for the current Plan Year or the Actual Deferral Percentage for the group of Non-Highly Compensated Employees for the current Plan Year multiplied by two, the deferral elections of the Highly Compensated Employees shall be reduced to the extent necessary so that the Actual Deferral Percentage for the group of Highly Compensated Employees is not more than the greater of subparagraphs (i) or (ii) of this subsection B. Under such reduction, the dollar amount of the Excess Before-Tax Contributions is determined as described in subsection A.(ii) above. Next, the Before-Tax Contributions of the Highly Compensated Employee with the highest dollar amount of Before-Tax Contributions (not necessarily the Highly Compensated Employee with the highest Actual Deferral Percentage) is reduced to the extent required to equal the maximum deferral dollar amount for Highly Compensated Employees permitted by subparagraphs (i) or (ii) of this subsection B., or to cause such Highly Compensated Employee's Before-Tax Contributions to equal the dollar amount of the Before-Tax Contributions of the Highly Compensated Employee with the next highest dollar amount of Before-Tax Contributions, whichever is less. This process is repeated until the aggregate dollar amount of all Highly Compensated Employee Before-Tax Contributions are reduced to an amount that will cause the dollar amount of the Before-Tax Contributions for all Highly Compensated Employees in the aggregate to equal the dollar amount of Before-Tax Contributions that will cause the average of the Actual Deferral Percentages for the group of Highly Compensated Employees to equal the maximum amount permitted under this Section. Alternatively (or in addition to the reductions set forth above), if the Employer has made any Qualified Matching or Qualified Non-elective Contributions for the Plan Year in question, the Committee may elect to treat all or any part of any such contributions meeting the requirements of Treasury Regulations Section 1.401(k)-1(b)(3) as Before-Tax Contributions to the extent necessary to satisfy the Actual Deferral Percentage test of this Section. Any Qualified Matching or Qualified Non-elective Contributions so applied shall not be included in the computation of the Actual Contribution Percentage test requirements of Code Section 401(m) otherwise applicable to such contributions.

C. **Testing Groups**. The Actual Deferral Percentage test may be performed separately with respect to those Participants who have met the minimum age and service requirements of Code Section 410(a)(1)(A) from those who have not met such requirements.

D. **Code Section 415 Limitation**. The Employer shall not make a contribution to the Trust to the extent the contribution would exceed the Participant's Maximum Permissible Amount described in this Schedule I.

E. **Multiple Code Section 401(k) Plans**. The Actual Deferral Percentage for any Participant who is a Highly Compensated Employee for the Plan Year and who is eligible to have Before-Tax Contributions (and Qualified Non-elective Contributions or Qualified Matching Contributions, or both, if treated as Before-Tax Contributions for purposes of the Actual Deferral Percentage test) allocated to his Accounts under two or more arrangements described in Code Section 401(k) that are maintained by the Employer, shall be determined as if such Before-Tax Contributions (and, if applicable, such Qualified Non-elective Contributions or Qualified Matching Contributions, or both) were made under a single arrangement. If a Highly Compensated Employee participates in two or more cash or deferred arrangements that have different Plan Years, all cash or deferred arrangements ending with or within the same calendar year shall be treated as a single arrangement.

F. **Optional Plan Aggregation**. In the event that this Plan satisfies the requirements of Code Sections 401(k), 401(a)(4), or 410(b) only if aggregated with one or more other plans, or if one or more other plans satisfy the requirements of such sections of the Code only if aggregated with this Plan, then this Section shall be applied by determining the Actual Deferral Percentage of Employees as if all such plans were a single plan. Plans may be aggregated in order to satisfy Code Section 401(k) only if they have the same Plan Year.

G. **Time for Making Contributions**. For purposes of determining the Actual Deferral Percentage test, Before-Tax Contributions, Qualified Non-elective Contributions and Qualified Matching Contributions must be made before the last day of the 12-month period immediately following the Plan Year to which such contributions relate. Before-Tax Contributions must, in any event, be paid over by the Employer to the Trustee by the earlier of the date on which they can reasonably be segregated from the Employer's general assets or within 15 business days after the end of the calendar month in which the Before-Tax Contributions were withheld from the Participant's Compensation.

H. **Recordkeeping**. The Committee shall maintain records sufficient to demonstrate satisfaction of the Actual Deferral Percentage test and the amount of Qualified Non-elective Contributions or Qualified Matching Contributions, or both, used in such test.

I. **Compliance with the Code**. The determination and treatment of the Actual Deferral Percentage amounts of any Participant shall satisfy such other requirements as may be prescribed by the Secretary of the Treasury. In performing the required testing hereunder, any variations in procedures or methods permitted under the Code and applicable Treasury Regulations may be employed.

Section I.02 DISTRIBUTION OF EXCESS BEFORE-TAX CONTRIBUTIONS (APPLICABLE TO PLAN YEARS PRIOR TO JANUARY 1, 2011). Notwithstanding any other provision of this Plan, Excess Before-Tax Contributions, plus any income and minus any loss allocable thereto, shall be distributed no later than the last day of each Plan Year to Participants to whose Accounts such Excess Before-Tax Contributions were allocated for the preceding Plan Year. Whenever possible, however, such distributions shall be made within two and one-half months after the end of the Plan Year during which the Excess Before-Tax Contributions occurred. Such distributions shall be made to Highly Compensated Employees on the basis of the respective portions of the Excess Before-Tax Contributions attributable to each of such Employees under the methodology described above. Excess Before-Tax Contributions shall be treated as Annual Additions under the Plan.

A. **Determination of Income or Loss**. Excess Before-Tax Contributions shall be adjusted for any income or loss. The Committee shall determine whether such adjustments shall include the Gap Period. Such adjustments shall include any income or loss through the end of the Plan Year in which the excess arose. For corrective distributions that are made for Plan Years beginning on and after January 1, 2006 and prior to January 1, 2008, such adjustments shall also include any income or loss for the period from the end of the taxable year in which the excess arose up to the date of distribution (or up to a date that is no more than seven days before the date of the corrective distribution) (the "Gap Period"). Gap Period adjustments shall not be made for Plan Years beginning on and after January 1, 2008. For Plan years beginning prior to January 1, 2006, Gap Period adjustments are made only in the discretion of the Committee. Alternatively, the Committee may determine the income or loss allocable to Excess Before-Tax Contributions under any reasonable method which does not violate the general nondiscrimination rules of Code Section 401(a)(4), is used consistently for all Participants and for all such corrective distributions under the Plan for the Plan Year, and is used by the Plan for allocating income to Participants' Accounts.

B. **Accounting for Excess Before-Tax Contributions**. Excess Before-Tax Contributions shall be distributed from the Participant's Before-Tax Account and Qualified Matching Contribution Account (if applicable) in proportion to the Participant's Before-Tax Contributions and Qualified Matching Contributions (to the extent used in the Actual Deferral Percentage test) for the Plan Year. Excess Before-Tax Contributions shall be distributed from the Participant's Qualified Non-elective Contribution Account only to the extent that such Excess Before-Tax Contributions exceed the balance in the Participant's Before-Tax Account and Qualified Matching Contribution Account.

Section I.03 DOLLAR LIMITATIONS ON ELECTIVE DEFERRALS.

A. **Definitions**.

(i) "Elective Deferrals" means any Employer contributions made to the Plan at the election of the Participant, in lieu of cash compensation, and shall include contributions made pursuant to a compensation reduction agreement or other deferral mechanism. With respect to any taxable year, a Participant's Elective Deferral is the sum of all employer contributions made on behalf of such Participant pursuant to an election to defer under any qualified cash or deferred arrangement as described in Code Section 401(k), any simplified employee pension cash or deferred arrangement as described in Code Section 402(h)(1)(B), any SIMPLE IRA described in Code Section 408(p), any eligible deferred compensation plan under Code Section 457, any plan described under Code Section 501(c)(18), and any employer contributions made on the behalf of a

Participant for the purchase of an annuity contract under Code Section 403(b) pursuant to a compensation reduction arrangement.

(ii) "Excess Elective Deferrals" means those Elective Deferrals that are includible in a Participant's gross income under Code Section 402(g) to the extent such Participant's Elective Deferrals for a taxable year exceed the dollar limitation under such Code section. Excess Elective Deferrals shall be treated as Annual Additions under the Plan, except to the extent they are distributed pursuant to subsection C. below.

B. **Prohibition of Deferrals in Excess of Code Section 402(g) Dollar Limitations**. No Participant shall be permitted to have Elective Deferrals made under this Plan, or any other qualified plan, during any taxable year, in excess of the dollar limitation contained in Code Section 402(g) (as adjusted for increases in the cost-of-living) in effect at the beginning of such taxable year, except to the extent Catch-up Contributions are permitted to be made to the Plan, as described in Code Section 414(v) or, effective for Plan Years on and after January 1, 2006, such Elective Deferrals are made by reason of a Participant's qualified military service under Code Section 414(u).

C. **Distribution of Excess Elective Deferrals**. A Participant may assign to this Plan any Excess Elective Deferrals made during a taxable year of the Participant by notifying the Plan Administrator on or before March 15 of the following taxable year of the amount of the Excess Elective Deferrals to be assigned to the Plan.

Notwithstanding any other provision of the Plan, Excess Elective Deferrals, plus any income and minus any loss allocable thereto, shall be distributed no later than April 15 to any Participant to whose Account Excess Elective Deferrals were assigned for the preceding year and who claims Excess Elective Deferrals for such taxable year.

D. **Determination of Income or Loss**. Excess Elective Deferrals shall be adjusted for any income or loss. Such adjustments shall include any income or loss through the end of the Plan Year in which the excess arose. For corrective distributions that are made for the Plan Year beginning January 1, 2007, such adjustments shall also include any income or loss for the period from the end of the taxable year in which the excess arose up to the date of distribution (the "Gap Period"). Gap Period adjustments shall not be made for Plan Years beginning on and after January 1, 2008. For Plan Years beginning prior to January 1, 2007, Gap Period adjustments are made only in the discretion of the Committee. The income or loss allocable to Excess Elective Deferrals is the sum of (i) income or loss allocable to the Participant's Elective Deferral Account for the taxable year multiplied by a fraction, the numerator of which is such Participant's Excess Elective Deferrals for the year and the denominator of which is the Participant's Account balance attributable to Elective Deferrals without regard to any income or loss occurring during such taxable year; and (ii) 10% of the amount determined under (i) multiplied by the number of whole calendar months between the end of the Participant's taxable year and the date of distribution, counting the month of distribution if distribution occurs after the 15th day of such month. Alternatively, the Committee may determine the income or loss allocable to Excess Elective Deferrals under any reasonable method which does not violate the general nondiscrimination rules of Code Section 401(a)(4), is used consistently for all Participants and all such corrective distributions under the Plan for the Plan Year, and is used by the Plan for allocating income to Participants' Accounts.

Participants who claim Excess Elective Deferrals for the preceding taxable year must submit their claims in writing to the Plan Administrator by March 15 of the calendar year following the Plan Year in which such Excess Elective Deferrals are claimed to have been made.

Section I.04 LIMITATIONS APPLICABLE TO MATCHING CONTRIBUTIONS.

A. **Definitions**. For purposes of this Section, the following definitions shall apply:

(i) "Aggregate Limit" shall mean the greater of (a) the sum of (1) 125% of the greater of the Actual Deferral Percentage of the Non-Highly Compensated Employees for the current Plan Year or the Actual Contribution Percentage of Non-Highly Compensated Employees under the Plan subject to Code Section 401(m) for the current Plan Year and (2) the lesser of 200% or two plus the lesser of such Actual Deferral Percentage or Actual Contribution Percentage; or (b) the sum of (1) 125% of the lesser of the Actual Deferral Percentage of the Non-Highly Compensated Employees for the current Plan Year or the Actual Contribution Percentage of Non-Highly Compensated Employees under the Plan subject to Code Section 401(m) for the current Plan Year, and (2) the lesser of 200% or two plus the greater of such Actual Deferral Percentage or Actual Contribution Percentage.

(ii) "Actual Contribution Percentage" shall mean the average of the Contribution Percentages of the Eligible Participants in a group.

(iii) "Contribution Percentage" shall mean the ratio (expressed as a percentage) of the Participant's Contribution Percentage Amounts to the Participant's Compensation for the Plan Year (whether or not the Employee was a Participant for the entire Plan Year).

(iv) "Contribution Percentage Amounts" shall mean the sum of the Matching Contributions and Qualified Matching Contributions (to the extent not taken into account for purposes of the Actual Deferral Percentage test) made under the Plan on behalf of the Participant for the Plan Year. Such Contribution Percentage Amounts shall not include the following: (a) Matching Contributions that are forfeited either to correct Excess Aggregate Contributions or because the contributions to which they relate are Excess Before-Tax Contributions, Excess Elective Deferrals, or Excess Aggregate Contributions, (b) Matching Contributions made by reason of an eligible employee's qualified military service under Code Section 414(u), and (c) disproportionate target Matching Contributions as described in Treasury Regulations Section 1.401(m)-2(a)(5)(ii). If it so desires, the Employer may make Qualified Non-elective Contributions designated for inclusion in the Contribution Percentage Amounts. The Employer also may elect to use Before-Tax Contributions in the Contribution Percentage Amounts so long as the Actual Deferral Percentage test is met before the Before-Tax Contributions are used in the Actual Contribution Percentage test and continues to be met following the exclusion of those Before-Tax Contributions that are used to meet the Actual Contribution Percentage test.

(v) "Eligible Participant" shall mean any Employee who is eligible to make a Before-Tax Contribution (if the Employer takes such contributions into account in the calculation of the Contribution Percentage), or to receive a Matching Contribution (including forfeitures) or a Qualified Matching Contribution. If an Employee contribution is required as a condition of participation in the Plan, any Employee who would be a Participant in the Plan if such Employee made such a contribution shall be treated as an eligible Participant on behalf of whom no Employee contributions are made.

(vi) "Employee Contribution" shall mean any voluntary employee nondeductible contribution made to the Plan by or on behalf of a Participant that is included in the Participant's gross income in the year in which made and that is maintained under a separate account to which earnings and losses are allocated.

(vii) "Excess Aggregate Contributions" shall mean, with respect to any Plan Year, the excess of:

1. The aggregate Contribution Percentage Amounts taken into account in computing the numerator of the Actual Contribution Percentage actually made on behalf of Highly Compensated Employees for such Plan Year, over

2. The maximum Contribution Amounts permitted by the Actual Contribution Percentage test (determined by reducing contributions made on behalf of Highly Compensated Employees in order of their Contribution Percentages beginning with the highest of such percentages).

Such determination shall be made after first determining Excess Before-Tax Contributions pursuant to Section I.01. After making such determination, the dollar amount of the Excess Aggregate Contributions shall be determined. The Excess Aggregate Contributions, on a dollar amount basis, shall be allocated to the Account(s) of the Highly Compensated Participant(s) with the highest dollar amount of Contribution Percentage Amounts allocated to his/their Account(s) in a reverse leveling process similar to the one described in Section I.01 applicable to Before-Tax Contributions.

(viii) "Matching Contribution" shall mean an Employer contribution made to this or any other defined contribution plan on behalf of a Participant on account of an Employee Contribution made by such Participant, or on account of a Participant's Before-Tax Contributions under a Plan maintained by the Employer.

B. **Actual Contribution Percentage Test**. The Actual Contribution Percentage for Participants who are Highly Compensated Employees for each Plan Year and the Actual Contribution Percentage for Participants who are Non-Highly Compensated Employees for the current Plan Year must satisfy one of the following tests:

(i) The Actual Contribution Percentage for Participants who are Highly Compensated Employees for the Plan Year shall not exceed the Actual Contribution Percentage for Participants who are Non-Highly Compensated Employees for the current Plan Year multiplied by 1.25; or

(ii) The Actual Contribution Percentage for Participants who are Highly Compensated Employees for the Plan Year shall not exceed the Actual Contribution Percentage for Participants who are Non-Highly Compensated Employees for the current Plan Year multiplied by two, provided that the Actual Contribution Percentage for Participants who are Highly Compensated Employees does not exceed such Actual Contribution Percentage for Participants who are Non-Highly Compensated Employees by more than two percentage points.

C. **Testing Groups**. The Actual Contribution Percentage test may be performed separately with respect to those Participants who have met the minimum age and service requirements of Code Section 410(a)(1)(A) from those who have not met such requirements.

D. **Aggregation of Contribution Percentage Amounts**. For purposes of this Section, the Contribution Percentage for any Participant who is a Highly Compensated Employee and who is eligible to have Contribution Percentage Amounts allocated to his Account under two or more Plans described in Code Section 401(a), or arrangements described in Section 401(k) that are maintained by the Employer, shall be determined as if the total of such Contribution Percentage Amounts was made under each plan. If a Highly Compensated Employee participates in two or more cash or deferred arrangements that have different plan years, all cash or deferred arrangements ending with or within the same calendar year shall be treated as a single arrangement.

E. **Aggregation of Plans**. In the event that this Plan satisfies the requirements of Code Sections 401(m), 401(a)(4) or 410(b) only if aggregated with one or more other plans, or if one or more other plans satisfy the requirements of such sections of the Code only if aggregated with this Plan, then this Section shall be applied by determining the Contribution Percentage of Employees as if all such plans were a single plan. Plans may be aggregated in order to satisfy Code Section 401(m) only if they have the same Plan Year.

F. **Allocation of Amounts to Plan Years**. For purposes of determining the Actual Contribution Percentage test, Employee Contributions are considered to have been made in the Plan Year in which contributed to the Trust. Matching Contributions and Qualified Non-elective Contributions shall be considered made for a Plan Year if made no later than the end of the 12-month period beginning on the day after the close of the Plan Year.

G. **Recordkeeping**. The Employer shall maintain records sufficient to demonstrate satisfaction of the Actual Contribution Percentage test and the amount of Qualified Non-elective Contributions or Qualified Matching Contributions, or both, used in such test.

H. **Code Requirements**. The determination and treatment of the Contribution Percentage of any Participant shall satisfy such other requirements as may be prescribed by the Secretary of the Treasury. In performing the required testing hereunder, any variations in procedures or methods permitted under the Code and applicable Treasury Regulations may be employed.

Section I.05 DISTRIBUTION OF EXCESS AGGREGATE CONTRIBUTIONS (APPLICABLE TO PLAN YEARS PRIOR TO JANUARY 1, 2011). Notwithstanding any other provision of this Plan, Excess Aggregate Contributions, plus any income and minus any loss allocable thereto, shall be forfeited, if forfeitable, or if not forfeitable, distributed no later than the last day of each Plan Year to Participants to whose Accounts such Excess Aggregate Contributions were allocated for the preceding Plan Year. Excess Aggregate Contributions shall be treated as Annual Additions under the Plan.

A. **Determination of Income or Loss**. Excess Aggregate Contributions shall be adjusted for any income or loss. Such adjustments shall include any income or loss through the end of the Plan Year in which the excess arose. For corrective distributions that are made for Plan Years beginning on and after January 1, 2006 and prior to January 1, 2008, such adjustments shall also include any income or loss for the period from the end of the taxable year in which the excess arose up to the date of distribution (or up to a date that is no more than seven days before the date of the corrective distribution) (the "Gap Period"). Gap Period adjustments shall not be made for Plan Years beginning on and after January 1, 2008. For Plan Years beginning prior to January 1, 2006, Gap Period adjustments will be made only in the discretion of the Committee. For Plan Years beginning prior to January 1, 2006, Gap Period adjustments were made only in the discretion of the Plan Administrator. The income or loss allocable to Excess Aggregate Contributions is the sum of: (i) income or loss allocable to the Participant's Matching Account and Qualified Matching Contribution Account (if any, and only to the extent that amounts therein are not used in the Actual Deferral percentage test), and Qualified Non-elective Contribution Account and Before-Tax Account if any such amounts were used in calculating the Actual Contribution Percentage test, for the Plan Year, multiplied by a fraction, the numerator of which is such Participant's Excess Aggregate Contributions for the year and the denominator of which is the Participant's Account balance(s) attributable to Contribution Percentage Amounts without regard to any income or loss occurring during such Plan Year; and (ii) 10% of the amount determined under (i) multiplied by the number of whole calendar months between the end of the Plan Year and the date of distribution, counting the month of distribution if distribution occurs after the 15th day of such month. Alternatively, the Committee may determine the income or loss allocable to Excess Aggregate Contributions under any reasonable method which does not violate the general nondiscrimination rules of Code Section 401(a)(4), is used consistently for all Participants and for all such corrective distributions under the Plan for the Plan Year, and is used by the Plan for allocating income to Participants' Accounts.

B. **Forfeitures of Excess Aggregate Contributions**. Forfeitures of Excess Aggregate Contributions may either be reallocated to the Accounts of Non-Highly Compensated Employees or applied to reduce Employer contributions, as elected by the Employer.

C. **Accounting for Excess Aggregate Contributions**. Excess Aggregate Contributions shall be forfeited, if forfeitable, or distributed on a pro-rata basis from the Participant's Employee Contribution Account, Matching Account, and Qualified Matching Contribution Account (and, if applicable, the Participant's Qualified Non-elective Contribution Account or Before-Tax Account, or both).

Section I.06 ALTERNATIVE TO DISTRIBUTION OF EXCESS AMOUNTS. In lieu of distributing Excess Before-Tax Contributions or Excess Aggregate Contributions and to the extent elected by the Employer, the Employer may make Qualified Non-elective Contributions on behalf of Non-Highly Compensated Employees that are sufficient to satisfy either the Actual Deferral Percentage test or the Actual Contribution Percentage test, or both, pursuant to regulations under the Code, and in accordance this Schedule I of the Plan.

Section I.07 ANNUAL ADDITIONS - DEFINITIONS. For purposes of this Section I.07, the following definitions and rules of interpretation shall apply:

A. "Annual Additions" are the sums of the following amounts credited to a Participant's Account for any Limitation Year:

(i) Before-Tax Contributions, Matching Contributions, and Qualified Matching Contributions and Safe Harbor Matching Contributions;

(ii) Supplemental Employer Contributions and Qualified Non-Elective Contributions, if any;

(iii) Forfeitures, if any; and

(iv) Excess amounts reapplied to reduce Employer contributions under Section I.08.

Except to the extent provided in Treasury Regulations, Annual Additions include any excess contributions described in Code Section 401(k), excess aggregate contributions described in Code Section 401(m), and excess deferrals described in Code Section 402(g), irrespective of whether the Plan distributes or forfeits such excess amounts.

Annual Additions also include amounts allocated to an individual medical account (as defined in Code Section 415(l)(2)) included as part of a pension or annuity plan maintained by the Company. Furthermore, Annual Additions include contributions attributable to post-retirement medical benefits allocated to the separate account of a Key Employee (as defined in Code Section 419(A)(d)(3)) under a welfare benefit fund (as defined in Code Section 419(e)) maintained by the Company. Allocations under a SEP which is maintained by the Company are treated as Annual Additions to a defined contribution plan. However, Annual Additions do not include Restorative Payments allocated to a Participant's Account. "Restorative Payments" are payments made to restore some or all of the Plan's losses due to an action (or failure to act) by a Plan fiduciary that creates a reasonable risk of liability for a breach of fiduciary duty (other than a breach of fiduciary duty arising from failure to remit contributions to the Plan) under Title I of ERISA or under other applicable federal or state law so long as Participants who are similarly situated are treated similarly with respect to the payments. Restorative Payments include, but are not limited to, payments to the Plan made pursuant to a Department of Labor order, the Department of Labor's Voluntary Fiduciary Correction Program, or a court-approved settlement, to restore losses to the Plan on account of a breach of fiduciary duty (other than a breach of fiduciary duty arising from failure to remit contributions to the Plan). In addition, dividends paid by an employee stock ownership plan (ESOP) and reinvested in the ESOP under Code Section 404(k)(2)(A)(iii)(II) are not Annual Additions.

An Annual Addition is credited to a Participant's Account for a Limitation Year if it is allocated to the Participant's Account under the terms of the Plan as of any date within that Limitation Year. Similarly, an Annual Addition that is made pursuant to a corrective amendment that complies with the requirements of Treasury Regulations Section 1.401(a)(4)-11(g) is credited to a Participant's Account for a Limitation Year if it is allocated to the Participant's Account under the terms of the corrective amendment as of any date within that Limitation Year. However, if the allocation of an Annual Addition is dependent upon the satisfaction of a condition (such as continued employment or the occurrence of an event) that has not been satisfied by the date as of which the Annual Addition is allocated under the terms of the Plan, the Annual Addition is considered allocated as of the date the condition is satisfied.

Before-Tax, Matching, Qualified Matching, Safe Harbor Matching, Supplemental Employer and Qualified Non-Elective Contributions, if any, are not treated as credited to a Participant's Account for a Limitation Year unless the contributions are actually made to the Plan no later than 30 days after the end of the period described in Code Section 404(a)(6) applicable to the taxable year with or within which the Limitation Year ends. If contributions are made to the Plan after the end of the period during which contributions can be made and treated as credited to a Participant's Account for a Limitation Year, allocations attributable to those contributions are treated as credited to the Participant's Account for the Limitation Year during which those contributions are made. A forfeiture is treated as an Annual Addition for the Limitation Year that contains the date as of which it is allocated to a Participant's Account as a forfeiture.

If the Company contributes an amount to a Participant's Account with respect to a prior Limitation Year and such contribution is required by reason of such Participant's rights under Code Section 414(u)(1), then such contribution is considered an Annual Addition for the Limitation Year to which the contribution relates instead of the Limitation Year in which the contribution is made. If an amount is allocated to a Participant's Account in a Limitation Year because of an erroneous forfeiture in a prior Limitation Year or because of an erroneous failure to allocate amounts in a prior Limitation Year, the corrective allocation will not be considered an Annual Addition with respect to the Participant for the Limitation Year in which the correction occurs, but will be considered an Annual Addition for the Limitation Year to which it relates. For purposes of the foregoing sentence, if the amount so contributed in the Limitation Year takes into account actual investment gains attributable to the period subsequent to the year to which the contribution relates, the portion of the total contribution that consists of such gains is not considered as an Annual Addition for any Limitation Year.

B. **"Company"** means any corporation that is a member of a controlled group of corporations (as defined in Code Section 414(b) as modified by Code Section 415(h)) that includes Chesapeake Utilities Corporation, or any trades or businesses (whether or not incorporated) that are under common control (as defined in Code Section 414(c) as modified by Code Section 415(h)) with Chesapeake Utilities Corporation, or a member of an affiliated service group (as defined in Code Section 414(m)) that includes Chesapeake Utilities Corporation, or any other entity required to be aggregated with Chesapeake Utilities Corporation pursuant to regulations under Code Section 414(o).

C. **"Compensation"** with respect to the Limitation Year means all remuneration received by an Employee for personal services actually rendered in the course of employment with the Company maintaining the Plan, which are subject to Federal income tax withholding at the source, plus the amounts that would be included in wages but for an election under Code Sections 125(a), 132(f)(4), 402(e)(3), 402(h)(1)(B), 402(k), or 457(b). For purposes of applying the limitations of this Schedule I, Compensation for a Limitation Year is the Compensation actually paid or includible in gross income during such Limitation Year. For Limitation Years beginning on and after January 1, 2008, Compensation shall not be greater than the limit under Code Section 401(a)(17) that applies to that year. Payments awarded by an administrative agency or court or pursuant to a bona fide agreement by the Company to compensate an Employee for lost wages are Compensation for the Limitation Year to which the back pay relates, but only to the extent such payments represent Compensation that would otherwise be Compensation under this Section I.07C.

If a Participant is permanently and totally disabled (as defined in Code Section 22(e)(3)), the Participant's Compensation means the Compensation the Participant would have received for the year if the Participant were paid at the rate of Compensation paid immediately before becoming permanently and totally disabled, if such Compensation is greater than the Participant's Compensation determined without regard to this paragraph. However, this paragraph applies only if the Participant is not a Highly Compensated Employee immediately before becoming disabled and contributions made with respect to amounts treated as Compensation under this paragraph are Nonforfeitable when made.

Generally, in order to be taken into account for a Limitation Year, Compensation must be paid or treated as paid to the Employee before the Employee's severance from employment with the Company. In addition to the foregoing, for Limitation Years beginning on and after January 1, 2008, Compensation shall include Post-Severance Compensation paid by the later of: (i) two and one-half (2½) months (or such other period as extended by subsequent Treasury Regulations or other published guidance) after severance from employment with the Company; or (ii) the end of the Limitation

Year that includes the date of the Employee's severance from employment with the Company. "Post-Severance Compensation" means payments that would have been included in the definition of Compensation if they were paid prior to the Employee's severance from employment and the payments are: (i) regular Compensation for Services during the Participant's regular working hours, Compensation for Services outside the Participant's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar compensation, if the payments would have been paid to the Employee if the Employee had continued in employment with the Company; (ii) for accrued bona fide sick, vacation or other leave, but only if the Participant would have been able to use the leave if employment had continued; or (iii) received by an Employee pursuant to a nonqualified unfunded deferred compensation plan, but only if the payment would have been paid to the Employee at the same time if the Employee had continued in employment with the Company and only to the extent the payment is includible in the Employee's gross income. Any payments not described in the preceding sentence are not considered Post-Severance Compensation if paid after severance from employment, except for payments (a) to an individual who does not currently perform services for the Company by reason of qualified military service (within the meaning of Code Section 414(u)(1)) to the extent these payments do not exceed the amounts the individual would have received if the individual had continued to perform services for the Company; or (b) to any Participant who is permanently and totally disabled for a fixed or determinable period, as determined by the Committee. For purposes of this Section I.07C., "permanently and totally disabled" means that the individual is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. For purposes of this Section I.07, "severance from employment" occurs when the Employee ceases to be an employee of the Company maintaining the Plan, and an Employee does not have a severance from employment if, in connection with a change of employment, the Employee's new employer maintains the Plan with respect to the Employee.

D. **"Defined Benefit Plan"** means a retirement plan that does not provide for individual accounts for Company contributions. The Committee shall treat all Defined Benefit Plans (whether or not terminated) maintained by the Company as a single plan.

E. **"Defined Contribution Plan"** means a retirement plan that provides for an individual account for each participant and for benefits based solely on the amount contributed to the participant's account, and any income, expenses, gains, and losses, and any forfeitures of accounts of other participants that the Committee may allocate to such participant's account. Solely for purposes of this Schedule I, the Committee shall treat employee contributions made to any Defined Benefit Plan maintained by the Company as a separate Defined Contribution Plan. The Committee shall treat as a Defined Contribution Plan an individual medical account (as defined in Code Section 415(l)(2)) included as part of a Defined Benefit Plan maintained by the Company and a welfare benefit fund under Code Section 419(e) maintained by the Company to the extent there are post-retirement medical benefits allocated to the separate account of a Key Employee (as defined in Code Section 419A(d)(3)). The Committee shall treat all

Defined Contribution Plans (whether or not terminated) maintained by the Company as a single plan.

F. **"Limitation Year"** means the Plan Year.

G. **"Maximum Permissible Amount"** means effective for Limitation Years beginning after December 31, 2001, with respect to any Participant, the lesser of:

(i) $40,000, as adjusted in accordance with Code Section 415(d), or

(ii) 100% of the Participant's Compensation for the Limitation Year.

The Compensation limit set forth in item (ii) above, shall not apply to any contribution for medical benefits (within the meaning of Code Section 401(h) or Code Section 419(f)(2)) after severance from employment, which is otherwise treated as an Annual Addition.

If there is a short Limitation Year because of a change in Limitation Year, the Committee will multiply the $40,000 limitation (or larger limitation) by the following fraction:

$$\frac{\text{Number of months in the short Limitation Year}}{12.}$$

B. Required Plan Aggregation. For purposes of applying the limitations of Code Sections 415(b), (c) and (e) applicable to a Participant for a particular Limitation Year, all qualified Defined Benefit Plans (without regard to whether a plan has been terminated) ever maintained by the Company will be treated as one Defined Benefit Plan and all qualified Defined Contribution Plans (without regard to whether a plan has been terminated) ever maintained by the Company will be treated as part of this Plan.

Section I.08 ANNUAL ADDITION LIMITATIONS. The amount of the Annual Additions that may be credited under this Plan to any Participant's Account as of any allocation date shall not exceed the Maximum Permissible Amount reduced by the sum of any credits of Annual Additions made to the Participant's Account under all Defined Contribution Plans as of any preceding allocation date within the Limitation Year.

If an allocation date of this Plan coincides with an allocation date of any other qualified Defined Contribution Plan maintained by the Company, the amount of the Annual Additions that may be credited under this Plan to any Participant's Account as of such date shall be an amount equal to the product of the amount to be credited under this Plan without regard to this Schedule I multiplied by the lesser of one or a fraction, the numerator of which is the amount described in this Section I.08 during the Limitation Year and the denominator of which is the amount that would otherwise be credited on this allocation date under all Defined Contribution Plans without regard to this Schedule I.

If contributions to this Plan on behalf of a Participant are to be reduced prior to their contribution to the Plan as a result of this Schedule I, such reduction shall be effected by first reducing the amount of any Employee Before-Tax Contributions (if permitted under the Plan) on behalf of such Participant and then, if necessary, by reducing Matching Contributions that would otherwise have been allocated to such Participant's Account. If, as a result of either (i) the allocation of forfeitures, or (ii) a reasonable error in estimating a Participant's Compensation, or (iii) a reasonable error in determining the amount of Before-Tax Contributions that may be made for the Participant under Code Section 415, or (iv) under the limited facts and circumstances which the Commissioner of Internal Revenue finds justify the availability of the rules set forth in subsections A. – D. of this Section I.08, the allocation of Annual Additions under the terms of the Plan for a particular Participant would cause the limitations of Code Section 415 applicable to that Participant for the Limitation Year to be exceeded, the excess amounts shall not be deemed to be Annual Additions in that Limitation Year if they are treated as follows:

A. The excess amounts in the Participant's Account consisting of Employee Before-Tax Contributions, if any, and any interest attributable thereto shall be paid to the Participant as soon as administratively feasible. Any amounts so distributed shall be disregarded for purposes of complying with the requirements of Code Section 402(g), the Actual Deferral Percentage test of Code Section 401(k)(3) and the Actual Contribution Percentage test of Code Section 401(m)(2).

B. The excess amounts in the Participant's Account consisting of Supplemental Employer Contributions or Matching Contributions shall be used to reduce Supplemental Employer Contributions or Matching Contributions, respectively, for the next Limitation Year (and succeeding Limitation Years, as necessary) for that Participant if that Participant is covered by the Plan as of the end of the Limitation Year. However, if that Participant is not covered by the Plan as of the end of the Limitation Year, then the excess amounts must be held unallocated in a suspense account for the Limitation Year and allocated and reallocated in the next Limitation Year to all of the remaining Participants in the Plan. If a suspense account is in existence at any time during a particular Limitation Year, other than the first Limitation Year described in the preceding sentence, all amounts in the suspense account must be allocated and reallocated to Participants' Accounts (subject to the limitations of Code Section 415) before any contributions that would constitute Annual Additions may be made to the Plan for that Limitation Year. Furthermore, the excess amounts must be used to reduce Supplemental Employer Contributions or Matching Contributions for the next Limitation Year (and succeeding Limitation Years, as necessary) for all of the remaining Participants in the Plan. For purposes of this subsection, except as provided in Section I.08A., excess amounts may not be distributed to Participants or Former Participants.

C. In the event of termination of the Plan, the suspense account described in subsection B., above, shall revert to the Company to the extent it may not then be allocated to any Participant's Account.

D. Notwithstanding any other provisions in this Schedule I, the Company shall not contribute any amount that would cause an allocation to the suspense account as of the date the contribution is allocated. If the contribution is made prior to the date as of which it is to be allocated, then such contribution shall not exceed an amount that would cause an allocation to the suspense account if the date of contribution were an allocation date.

E. If a Participant's Annual Additions would result in an excess amount for a Limitation Year, the excess amount will be deemed to consist of the Annual Additions last allocated except that Annual Additions attributable to a welfare benefit fund will be deemed to have been allocated first regardless of the actual allocation date.

The correction methods set forth in subsections A. – E., above, are not available for Limitation Years beginning on and after January 1, 2008. For Limitation Years beginning on and after January 1, 2008, corrections for excess Annual Additions shall be made in a manner consistent with the Employee Plans Compliance Resolution System ("EPCRS") issued by the Internal Revenue Service, as in effect from time to time.

Section I.09 FURTHER REDUCTIONS OF CONTRIBUTIONS. In any Plan Year in which the Committee deems it necessary to do so to meet the requirements of this Schedule I or the Code and the Treasury Regulations thereunder, the Committee may further reduce the amount of Contributions that may be made to a Participant's Account.

Section I.10 AGGREGATION RULES. The rules under Code Section 415(j) shall apply as appropriate for purposes of this Schedule I for Limitation Years that begin on or after January 1, 2008. In no event shall a Participant's benefit be double counted in the application of these aggregation rules. The limitations of this Schedule I shall be determined and applied taking into account the aggregation rules provided herein, and the aggregation rules not otherwise provided in this Schedule I, as incorporated by reference from Treasury Regulations Section 1.415(f)-1. However, any increase in benefits resulting from the application of such rules in effect as of the Limitation Year beginning on or after January 1, 2008, shall apply only to Participants who have completed at least one Hour of Service with the Company after said date.

Section I.11 INCORPORATION BY REFERENCE. Notwithstanding anything contained in this Schedule I to the contrary, the limitations, adjustments and other requirements provided in this Schedule I shall at all times comply with the provisions of Code Section 415 and the Treasury Regulations issued thereunder, the terms of which are specifically incorporated into this Plan by reference.

Section I.12 REPEAL OF PROVISION. Should Congress provide by statute, or the Internal Revenue Service provide by regulation or ruling, that any or all of the conditions set forth in this Schedule I are no longer necessary for the Plan to meet the requirements of Code Section 401 or other applicable provisions of the Code then in effect, such conditions shall immediately become void and shall no longer apply, without the necessity of further amendment to the Plan.

SCHEDULE II
PARTICIPATING EMPLOYERS

BravePoint, Inc.

Chesapeake Utilities Corporation

Central Florida Gas

Eastern Shore Natural Gas Company

Peninsula Energy Services Company, Inc.

Sharp Energy, Inc.

Sharpgas, Inc.

Xeron, Inc.

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