STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

SAMPLE APPLICATION FORM FOR:

THE REGISTRATION OF

COMPETITIVE ELECTRIC POWER SUPPLIERS (CEPS)

NOTE: When completing this application electronically, using the "tab" key after addressing each item will move the cursor to the next item. Please note that there are certain attachments to be included with this application.

This signed application, together with an electronic copy on diskette, pursuant to Puc 202, shall be filed with the Executive Director and Secretary of the New Hampshire Public Utilities Commission (Commission). Any omissions and/or deficiencies which need to be corrected will be completed in a timely manner or the Commission may close this proceeding without prejudice.

1. Please check the appropriate box: [X] ORIGINAL NOTICE [ ] RENEWAL NOTICE

2. Applicant's legal name: Constellation NewEnergy, Inc.

3. Trade name(s) under which the applicant will operate: N/A

4. Business address: (1) 116 Huntington Avenue
   (2) Suite 700
   (3)
   Boston (City) MA (State) O2116 (Zip Code)

5. Principal place of business: 100 Constellation Way, Baltimore MD 21202

6. Telephone number: 410-470-3582

7. Facsimile number: 443-213-6388

8. Email address: Joseph.Donovan@constellation.com

9. Applicant's place of incorporation: Delaware

10. Name, title, business address, telephone number and facsimile number of the applicant's principal officers: (File this on a separate page(s) labeled "Exhibit A")

11. A copy of the applicant's most recent audited financial statement: (Attach as "Exhibit B")

12. The following regarding any affiliate and/or subsidiary of the applicant or N/A: ☐

(a) The name and business address of the entity:

Please see Attachment A.

(b) A description of the business purpose of the entity:

The listed entities are electricity suppliers and/or provide related retail electricity functions.

(c) A description of the nature of any agreement with an affiliated New Hampshire jurisdictional electric company:

N/A

13. The toll free telephone number of the customer service department: 866-237-7693
OR the name, title and toll free telephone number of the customer service contact person:

N/A	N/A	N/A
(Name)	(Title)	(Telephone Number)

14. For the individual responsible for responding to Commission inquiries:

(a) Name: Joseph Donovan

(b) Title: Senior Counsel

(c) Business address: 100 Constellation Way, Suite 500C, Baltimore, MD 21202

(d) Telephone number: 410-470-3582

(e) Facsimile number: 443-213-6388

(f) Email address: Joseph.Donovan@constellation.com

15. For the applicant's registered agent in New Hampshire for service of process:

(a) Name: CT Corporation

(b) Title: N/A

(c) Business address: 9 Capitol Street, Concord, NH 03301

(d) Telephone number: N/A

16. When filing an ORIGINAL application, a copy of the applicant's authorization to do business in New Hampshire from the New Hampshire Secretary of State: (Attach as "Exhibit C")

17. A description of the geographic areas of New Hampshire in which the applicant intends to provide service, described by a distribution company's existing franchise area, existing town boundaries, or a map with the boundary limits delineated:

CNE will provide service in the following distribution utility footprints:

Granite State Electric Company (GSECO), New Hampshire Electric Cooperative Inc. (NHEC),

Unitil Energy Systems, Inc. (UES), Public Service Company of New Hampshire (PSNH)

18. A description of the types of customers the applicant intends to serve and the customer classes as identified in the applicable utility's tariff within which those customers are served:

CNE will serve large commercial and industrial customers in the following customer classes:

NHEC – B, B2, B3, B32, BH, IND, LB, LB3, LB32, LGT09, LGT10, LGT12, P, PS and SKI

PSNH – G, GV, LG, OL, R

UES – D, G1, G-1, G2, OL

GSECO – DOO, G1, G2, G3, M00, T00, V00

19. A listing disclosing the number and type of customer complaints concerning the applicant or its principals, if any, filed with a state licensing/registration agency, attorney general's office or other governmental consumer protection agency for the most recent calendar year in every state in which the applicant has conducted business relating to the sale of electricity. (Check the appropriate box)

☐ Not Applicable ☒ Applicable (See "Exhibit D" for explanation)

20. A statement as to whether any of the applicant's principals, as listed in (a) through (c) below, have ever been convicted of any felony that has not been annulled by a court.
   (a) For partnerships, any of the general partners;
   (b) For corporations, any of the officers or directors; or
   (c) For limited liability companies, any of the managers or members. (Check the appropriate box)

   [X] Not Applicable   [ ] Applicable (See "Exhibit E" for explanation)

21. A statement as to whether the applicant or any of the persons listed in (19) above has, within the 10 years immediately prior to registration:
   (a) Had any civil, criminal or regulatory sanctions or penalties imposed against them pursuant to any state or federal consumer protection law or regulation;
   (b) Settled any civil, criminal or regulatory investigation or complaint involving any state or federal consumer protection law or regulation; or
   (c) Is currently the subject of any pending civil, criminal or regulatory investigation or complaint involving any state or federal consumer protection law or regulation. (Check the appropriate box)

   [X] Not Applicable   [ ] Applicable (See "Exhibit F" for explanation)

22. For those applicants intending to telemarket, a statement that the applicant shall:
   (a) Maintain a list of consumers who request being placed on a do-not-call list for the purposes of telemarketing;
   (b) Obtain, no less than semi-annually, access to updated telephone preference services lists maintained by the Direct Marketing Association; and
   (c) Not initiate calls to New Hampshire customers who have either requested being placed on do-not-call lists or customers who are listed on the Direct Marketing Association's telephone preference lists.

   CNE does not currently intend to launch a telemarketing campaign in the state of New Hampshire. However, if these plans change, CNE will adhere to all provisions of applicable law, including the above requirements, and will notify the Commission of its intentions.

23. For those applicants that intend not to telemarket, a statement to that effect:

   See statement in question 22 above.

24. A sample of the bill form(s) that the applicant intends to use or a statement that the applicant intends to use the transmission/distribution company's billing service (Attach as "Exhibit G").

25. A copy of each contract to be used for residential and small commercial customers or a statement that electricity will not be sold to those customers (Attach as "Exhibit H").

26. A statement certifying that the person completing the application has the authority to file the application on behalf of the CEPS and that its contents are truthful, accurate and complete (Attach as "Exhibit I").

27. Each CEPS applicant shall provide the following in or with its application:

   (a) Demonstration of technical ability to provide for the efficient and reliable transfer of data and electronic information between regulated distribution companies and CEPS in the form of:

(i) A statement from each electric distribution company with which the CEPS intends to do business indicating that the applicant has complied with the training and testing requirements for electronic data interchange (Attach as "Exhibit J"); and

(ii) A statement from each electric distribution company with which the CEPS intends to do business indicating that the applicant has successfully demonstrated electronic transaction capability (Attach as "Exhibit K").

(b) Evidence, including but not limited to proof of membership in the New England Power Pool (NEPOOL) or any successor organization or documentation of a contractual sponsorship relationship with a NEPOOL member, that the CEPS is able to obtain supply in the New England energy market (Attach as "Exhibit L").

(c) A $500.00 registration fee, made payable to the "New Hampshire Public Utilities Commission".

(d) Evidence of financial security, as follows (Attach as "Exhibit M"):

(i) The security shall be in the form of a surety bond or other financial instrument showing evidence of liquid funds, such as a certificate of deposit, an irrevocable letter of credit, a line of credit, a loan or a guarantee.

(ii) The security amount shall be the greater of $100,000 or 20% of the CEPS's estimated gross receipts for its first full year of operation, not including revenue from the provision of transition or default service and shall not exceed $350,000.00.

(iii) The security shall name the Commission as obligee.

NOTE: When the security amount required for CEPS is based on gross receipts, the CEPS shall annually adjust the amount of the security based on its gross receipts, not including revenues from the provision of transition and default service.

28. The CEPS shall notify any transmission and distribution utility doing business in an area where the CEPS intends to compete of its registration application at the time it files such application with the Commission (Attach a copy of these notifications as "Exhibit N").

29. The CEPS shall confirm with the transmission and distribution utility that it has successfully completed its registration upon receipt of approval from the Commission (Forward a copy of these confirmations to the Commission).

30. An electronic copy of this notice of intent (on diskette) is included. YES [X] NO [ ]

NOTE:

- Each CEPS shall notify the Commission of any changes to the information required in this section within 30 days following the effective date of the change.
- The CEPS registration period shall run for 2 years.
- Each CEPS shall re-register with the Commission every 2 years on or before its original registration anniversary date by filing with the Commission an application for renewal. If a CEPS fails to meet its re-filing obligation, the original registration shall expire.

- The CEPS shall include on each renewal application an update noting any changes to all information contained in the previous application.
- The CEPS shall include with its renewal application a re-registration fee of $250.00.
- Unless additional time is required to review the application and the Commission extends the review period, a registration application shall be deemed to have been approved 60 days after receipt by the Commission of the completed application.
- This application and all future correspondence should be sent to:

  Ms. Debra A. Howland
  Executive Director and Secretary
  State of New Hampshire
  Public Utilities Commission
  21 S. Fruit St, Suite 10
  Concord, NH 03301-2429

31. Preparer's Name and Title: Joseph ______

32. Preparer's Signature: SENIOR COUNSEL

EXHIBIT A

EXHIBIT A
Constellation NewEnergy, Inc.
Officers and Directors

Corporate Officers

Michael Kagan
President & CEO
800 Boylston St, 28th Flr
Boston, MA 02199
617-772-7533
617-772-7550 Fax
michael.kagan@constellation.com

Jonathan W. Thayer
CFO
111 Market Place, 6th Flr
Baltimore, MD 21202
410-470-3450
410-470-6200 Fax
jack.thayer@constellation.com

Stuart R. Rubenstein
COO
111 Market Place, 5th Flr
Baltimore, MD 21202
410-468-3430
410-468-3540 Fax
stuart.rubenstein@constellation.com

Reese K. Feuerman
Treasurer
750 East Pratt Street, 16th Flr
Baltimore, MD 21202
410-470-3233
Reese.feuerman@constellation.com

Charles A. Berardesco
Secretary
750 Pratt Street, 17th Flr
Baltimore, MD 21202
410-470-3011
410-470-5741 Fax
charles.berardesco@constellation.com

Randall D. Osteen
Assistant Secretary
111 Market Place, 5th Flr
Baltimore, MD 21202
410-470-3121
410-468-3499 Fax
randall.osteen@constellation.com

Martin Hunter
Vice President, Tax
111 Market Place, 5th Flr
Baltimore, MD 21202
410-470-2426
martin.hunter@constellation.com

Corporate Directors

Mark P. Huston
111 Market Place, 12th Flr
Baltimore, MD 21202
410-470-2846
mark.huston@constellation.com

Kathleen W. Hyle
750 East Pratt Street, 15th Flr
Baltimore, MD 21202
410-470-3387
kathleen.hyle@constellation.com

Edward J. Quinn
111 Market Place, 12th Flr
Baltimore, MD 21202
410-470-3130
edward.quinn@constellation.com

EXHIBIT B

EXHIBIT C

State of New Hampshire
Department of State

AMENDED CERTIFICATE OF AUTHORITY OF

AES NEWENERGY, INC.

The undersigned, as Deputy Secretary of State of the State of New Hampshire, hereby certifies that an Application of AES NEWENERGY, INC. for an Amended Certificate of Authority to transact business in this State, duly signed pursuant to the provisions of the New Hampshire Business Corporation Act, has been received in this office.

ACCORDINGLY the undersigned, as such Deputy Secretary of State, and by virtue of the authority vested in him by law, hereby issues this Amended Certificate of Authority to CONSTELLATION NEWENERGY, INC. to transact business in this State under the name of CONSTELLATION NEWENERGY, INC. and attaches hereto a copy of the Application for such Amended Certificate.

IN TESTIMONY WHEREOF, I hereto set my hand and cause to be affixed the Seal of the State of New Hampshire, this 4th day of October, 2002.

Robert P. Ambrose
Deputy Secretary of State

EXHIBIT D

Exhibit D

Constellation NewEnergy, Inc.

Region	Category	Complaint Numbe	Date Received	Date Responded	Violation
Texas	Rates/Charges	CP2009030806	3/9/2009	3/30/2009	No
Texas	Rates/Charges	CP2009032088	3/20/2009	4/9/2009	No
Texas	No Bill Received	CP2009032135	3/25/2009	4/15/2009	No
GLR	Service	5517006324	3/27/2009	4/7/2009	No
Texas	Customer Service	CP2009061022	6/16/2009	7/6/2009	No
Texas	Customer Service	CP2009071912	7/27/2009	7/31/2009	No
Texas	Customer Service	CP2009081316	8/12/2009	n/a	No
Texas	Rates/Charges	CP2009082859	8/31/2009	9/15/2009	No
Texas	Customer Service	CP2009090325	9/4/2009	9/15/2009	No
Texas	Rates/Charges	CP2009091498	9/21/2009	10/13/2009	No
New England	Rates/Charges	168289	9/15/2009	9/29/2009	No
Texas	Rates/Charges	CP2009091680	9/23/2009	n/a	No
GLR	Customer Service	2009-23369	10/8/2009	10/29/2009	No
New England	Rates/Charges	n/a	10/29/2009	11/6/2009	No
New England	Rates/Charges	n/a	10/6/2009	n/a	No
New England	Rates/Charges	n/a	10/29/2009	11/6/2009	No
Ontario	Rates/Charges	2009-0010262	9/29/2009	10/28/2009	No
Texas	Customer Service	CP2009110323	11/5/2009	11/20/2009	No
Texas	Rates/Charges	CP2009121378	12/29/2009	1/5/2010	No
New England	Rates/Charges	n/a	11/16/2009	12/2/2009	No
New England	Rates/Charges	n/a	12/17/2009	1/15/2010	No
Metro North	Unauthorized Switch	09V00018618	12/2/2009	12/9/2009	No

EXHIBIT G

Constellation NewEnergy®

The way energy **works.** *for your business*

Invoice

ACCOUNT ID.	[redacted]	[redacted]
CUSTOMER NO.	[redacted]	
STATEMENT NO.	0001769445	
STATEMENT DATE	04/29/2010	
DUE DATE	**05/29/2010**	

Additional charges per the terms of your contract will be applied to the **Total Amount Due** if payment is not received on or before the due date.

PREVIOUS STATEMENT DATE	03/29/2010	
PREVIOUS BALANCE		[redacted]
PAYMENTS SINCE LAST INVOICE		[redacted]
DEBITS/CREDITS SINCE LAST INVOICE		[redacted]
LATE/FINANCE FEE		[redacted]
CURRENT CHARGES		[redacted]
TOTAL AMOUNT DUE		[redacted]

Our remittance instructions have changed. The new remittance instructions are listed on this invoice, please update your records accordingly.

WIRE TRANSFER INFORMATION:
Constellation NewEnergy, Inc.
[redacted]
BANK: Bank of America

REMITTANCE ADDRESS:
Constellation NewEnergy, Inc.
14217 Collections Center Dr.
Chicago, IL 60693

6142 RBG 000 07 100429 PAGE 1 of 4 COLR628E

(PLEASE RETURN THIS PORTION WITH PAYMENT, AND MAKE ALL CHECKS PAYABLE TO: Constellation NewEnergy, Inc.)

ACCOUNT ID.	[redacted]
CUSTOMER NO.	[redacted]
STATEMENT NO.	0001769445
STATEMENT DATE	04/29/2010
DUE DATE	05/29/2010

If billing address is incorrect, please fax the new complete billing address to (877) 243-4968.

Additional charges per the terms of your contract will be applied to the **Total Amount Due** if payment is not received on or before the due date.

[redacted]

AMOUNT DUE [redacted]
AMOUNT ENCLOSED $__________

Constellation NewEnergy®

The way energy **works.** *for your business*

Michaels Stores Inc. — **Fixed Price Solutions**

SITE NAME	[redacted]		
SERVICE LOCATION	[redacted]	**kWh**	[redacted]
UES ACCOUNT NO.	[redacted]	**SERVICE PERIOD**	**03/24/2010 to 04/23/2010**
INVOICE DETAIL NO.	[redacted]		
METER NO(S).	152500		

Contract Charges					
Energy Charge Non TOU	[redacted] kWh at	[redacted]	$/kWh	[redacted]	
Subtotal Contract Charges					[redacted]
Market Charges					
Capacity Charge $/kW Day 03/24/2010 - 03/31/2010 (Capacity Tag 139.92kW x Reserve Margin 1.510295 x 8 Days x Capacity Price)	[redacted] kW Days at	[redacted]	$/kW Days	[redacted]	
Capacity Charge $/kW Day 04/01/2010 - 04/23/2010 (Capacity Tag 139.92kW x Reserve Margin 1.518236 x 23 Days x Capacity Price)	[redacted] kW Days at	[redacted]	$/kW Days	[redacted]	
Subtotal Market Charges					[redacted]
Subtotal Charges from Constellation NewEnergy					[redacted]
Total Amount Due To Constellation NewEnergy					[redacted]

EXHIBIT H

EXHIBIT H:

CNE does not currently intend to provide service to residential or small commercial customers.

EXHIBIT I

Exhibit I:

Under penalty of perjury, the undersigned hereby affirms that he/she is authorized to and hereby does make this re-application for Constellation NewEnergy, Inc. and that based upon personal knowledge and information, the contents of this Application are truthful, accurate and complete.

May 4, 2010

Stuart Rubenstein
Chief Operating Officer, CNE

EXHIBIT J

From: kelly.j.ryan@accenture.com [mailto:kelly.j.ryan@accenture.com]
Sent: Thursday, April 15, 2010 9:17 AM
To: Engel, Thomas
Cc: kevin.j.perry@accenture.com; Sigg, Matt
Subject: FW: CNE Completed Testing!

Dear Tom,

Good morning. Below is the email confirming we have completed certification testing with NGRID!

Thank you,
Kelly

Kelly J. Ryan
Accenture Transaction Management Services (ATMS)
kelly.j.ryan@accenture.com
office: 610 994 2855
mobile: 267 939-7875

From: Laura, Donna Marie [mailto:DonnaMarie.LAURA@us.ngrid.com]
Sent: Thursday, April 15, 2010 10:10 AM
To: Ryan, Kelly J.
Subject: CNE Completed Testing!

Please know that testing has been officially completed!

Thank you for your patience with this process.

Regards,

Donna Marie Laura
Supplier Services
National Grid
175 E. Old Country Road - Ground Floor
Hicksville, NY 11801
516-545-4939
Email - supplier.services@us.ngrid.com

From: kelly.j.ryan@accenture.com [mailto:kelly.j.ryan@accenture.com]
Sent: Monday, May 03, 2010 1:18 PM
To: Sigg, Matt; Engel, Thomas
Subject: RE: 20100413 Constellation Certification Testing

Dear Matt –

Please let the email below, confirming testing was completed.

From: pauljb@nu.com [mailto:pauljb@nu.com]
Sent: Monday, May 03, 2010 2:13 PM
To: Ryan, Kelly J.
Cc: downiaj@nu.com; ITEDI@nu.com; kennijf@nu.com; wilkspp@nu.com; bondpk@nu.com
Subject: Re: FW: Recert Testing For Constellation

Hi Kelly,

CL&P, WMECO and PSNH successfully completed EDI testing on February 22, 2010.

Jean

Jean B Paul
Supplier Relations
Internal Phone # 607-6642
External Phone #860-607-6642
FAX # 860-607-6163

Thank you,
Kelly

Kelly J. Ryan
Accenture Transaction Management Services (ATMS)
kelly.j.ryan@accenture.com
office: 610 994 2855
mobile: 267 939-7875

From: Sigg, Matt [mailto:Matt.Sigg@Constellation.com]
Sent: Monday, May 03, 2010 12:48 PM
To: Ryan, Kelly J.; Engel, Thomas
Subject: RE: 20100413 Constellation Certification Testing
Importance: High

Kelly/Tom,

Can you send me the email communication from NU specifically for PSNH that CNE completed EDI certification testing?

Thanks,

From: Fournier, Rich [mailto:fournier@unitil.com]
Sent: Tuesday, May 04, 2010 12:09 PM
To: Sigg, Matt
Cc: Pascoe, Carrie
Subject: Unitil UES and CNE EDI certfication status.

This is to certify that Constellation New Energy has successfully completed all testing requirements with Unitil UES on 02/05/2010 and with Unitil FGE on 2/12/2010.

EXHIBIT K

EXHIBIT K:

Please see Exhibit J for correspondence from utilities confirming CNE has demonstrated electronic transfer capabilities.

EXHIBIT L

NEPOOL Participants
Alpha by Voting Member
Related Persons indented beneath

NAME OF PARTICIPANT	Generation Sector	Transmission Sector	Supplier Sector	AR Sector	Publicly-Owned Entity Sector	End User Sector
Conservation Services Group, Inc. (LR Sub-Sector)				1		
Consolidated Edison Energy, Inc.			1			
Consolidated Edison Development, Inc.						
Consolidated Edison Solutions, Inc.						
Consolidated Edison Co. of New York, Inc.						
Constellation Energy Commodities Group, Inc.			1			
Constellation NewEnergy, Inc.						
Corinth Wood Pellets LLC (L)						1
Corinth Energy LLC						
Covanta Maine, LLC (RG Sub-Sector)				1		
Covanta Haverhill Associates, LP						
CP Energy Marketing (US) Inc.			1			
CPower, Inc. (LR Sub-Sector)				1		
Credit Suisse Energy LLC			1			
Boralex Stratton Energy, Inc.						
Milford Power Company, LLC						
Danvers Electric Division					1	
DB Energy Trading, LLC			1			
Deutsche Bank AG, London Branch						
DC Energy, LLC			1			
Dennis Beverage Company Inc. (S)						1
Dennis Energy Company						
Devonshire Energy			1			
Backyard Farms LLC						
Backyard Farms Energy LLC						
DFC-ERG Milford, LLC (RG Sub-Sector)				1		
Bridgeport Fuel Cell Park, LLC						
DFC ERG CT LLC						
Discount Power, Inc.			1			
Dominion Energy Marketing, Inc.	1					
Dominion Nuclear Connecticut, Inc.						
Dominion Retail, Inc.						
DownEast Power Company LLC				1		
Dragon Products (L)						1
Dragon Energy						
DTE Energy Trading, Inc.			1			
Duke Energy Ohio, Inc						
CinCap V, LLC			1			
Duke Energy Commercial Enterprises, Inc.						
Cinergy Services, Inc.						
Dynegy Power Marketing, Inc.			1			
Calpine Energy Services, LP						
Dighton Power Associates LP						
Rumford Power Associates LP						
Tiverton Power Associates LP						
Easy Energy of Massachusetts, LLC			1			
EDF Trading North America, LLC			1			
Edison Mission Marketing & Trading, Inc.			1			
eKapital Investments LLC			1			
Elektrisola, Inc. (L)						1

EXHIBIT M

Confidential Material

EXHIBIT N

Constellation Energy

111 Market Place
Suite 500
Baltimore, Maryland 21202

May 04, 2010

Via Overnight Delivery

Granite State Electric Company
ATTN: General Counsel
9 Lowell Road
Salem, NH 03079-2902

Public Service Co of NH
ATTN: General Counsel
1000 Elm Street
Manchester NH 03105

NH Electric Cooperative Inc
ATTN: Billo Bayard
579 Tenney Mountain Hwy
Plymouth NH 03264-3147

Unitil Energy Systems, Inc.
ATTN: General Counsel
One Mcguire St.
Concord, NH 03301

Theodore J. Paradise
Senior Regulatory Counsel
Independent Systems Operator –
New England
One Sullivan Road
Holyoke, MA 01040

Unitil Energy Systems, Inc.
ATTN: General Counsel
114 Drinkwater Rd.
Kensington NH 03833

To whom it may concern:

As part of its New Hampshire licensing obligations, Constellation NewEnergy, Inc. is required to provide certain notices to transmission and distribution utilities. Please be advised that, consistent with Part 2003.01 of the New Hampshire Code of Administrative Rules, Chapter PUC 2000, Constellation NewEnergy, Inc. has submitted its 2010 Competitive Electric Power Supplier registration to serve Large Commercial and Industrial customers as a Competitive Electric Power Supplier in New Hampshire.

Please call with any questions.

Sincerely,

Joseph E. Donovan
Senior Counsel
Constellation Energy Resources, LLC
On behalf of Constellation NewEnergy, Inc.
410.470.3582

Attachment A

Attachment A

Baltimore Gas & Electric Company
BGE Home Products & Services, Inc.
Constellation NewEnergy, Inc.
Constellation Energy Products & Services Group, Inc.
Constellation Energy Commodities Group Maine LLC (f/k/a Constellation Power Source Maine, LLC)
Constellation Energy Commodities Group Massachusetts LLC (f/k/a Constellation Power Source Massachusetts, LLC)
Constellation Energy Commodities Group New Hampshire, LLC (f/k/a Constellation Power Source New Hampshire, LLC)
Constellation NewEnergy-Gas Division, Inc.

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **DECEMBER 31, 2009**

Commission file number	Exact name of registrant as specified in its charter	IRS Employer Identification No.
1-12869	**CONSTELLATION ENERGY GROUP, INC.**	**52-1964611**
	100 CONSTELLATION WAY, BALTIMORE, MARYLAND 21202	
	(Address of principal executive offices) (Zip Code)	
	410-470-2800	
	(Registrants' telephone number, including area code)	
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**
	2 CENTER PLAZA, 110 WEST FAYETTE STREET, BALTIMORE, MARYLAND 21202	
	(Address of principal executive offices) (Zip Code)	
	410-234-5000	
	(Registrants' telephone number, including area code)	

MARYLAND

(States of incorporation of both registrants)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Title of each class	Name of each exchange on which registered
Constellation Energy Group, Inc. Common Stock—Without Par Value	New York Stock Exchange Chicago Stock Exchange
Constellation Energy Group, Inc. Series A Junior Subordinated Debentures 6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, based on several obligations, by Baltimore Gas and Electric Company	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:
Not Applicable

Indicate by check mark if Constellation Energy Group, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐.

Indicate by check mark if Baltimore Gas and Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐.

Indicate by check mark if Constellation Energy Group, Inc. is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark if Baltimore Gas and Electric Company is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark whether the registrants (1) have 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, and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether Constellation Energy Group, Inc. 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 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 whether Baltimore Gas and Electric Company 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 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 whether Constellation Energy Group, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the 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 ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether Baltimore Gas and Electric Company 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 ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether Constellation Energy Group, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☒

Indicate by check mark whether Baltimore Gas and Electric Company is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☒

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2009 was approximately $5,309,415,341 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
201,091,187 SHARES OUTSTANDING ON JANUARY 29, 2010.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2010 Annual Meeting of Shareholders for Constellation Energy Group, Inc.

Baltimore Gas and Electric Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form in the reduced disclosure format.

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Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "anticipates," "expects," "intends," "plans," and other similar words. We also disclose non-historical information that represents management's expectations, which are based on numerous assumptions. These statements and projections are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices and volatilities for energy and energy-related products including coal, natural gas, oil, electricity, nuclear fuel, and emission allowances, and the impact of such changes on our liquidity requirements,
- the liquidity and competitiveness of wholesale and retail markets for energy commodities,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric's (BGE) ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,
- the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets, including generating facilities and new nuclear generation development projects,
- the effect of weather and general economic and business conditions on energy supply, demand, prices, and customers' and counterparties' ability to perform their obligations or make payments,
- the ability to attract and retain customers in our Customer Supply activities and to adequately forecast their energy usage,
- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,
- regulatory or legislative developments federally, in Maryland, or in other states that affect energy deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to safety, or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the ability of BGE to recover all its costs associated with providing customers service,
- operational factors affecting commercial operations of our generating facilities and BGE's transmission and distribution facilities, including weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the impact of industry consolidation,
- the impact of increased energy conservation and use of renewable energy,
- the actual outcome of uncertainties associated with assumptions and estimates requiring judgment when managing our business, applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),
- changes in accounting principles or practices, and
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the Securities and Exchange Commission (SEC) for more information on these factors. These forward looking statements represent our estimates and assumptions only as of the date of this report.

Changes may occur after that date, and neither Constellation Energy nor BGE assumes responsibility to update these forward looking statements.

PART I
Item 1. Business

Overview

Constellation Energy is an energy company that includes a merchant energy business and BGE, a regulated electric and gas public utility in central Maryland. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Our merchant energy business is primarily a competitive provider of energy-related products and services for a variety of customers. It develops, owns, owns interests in, and operates electric generation facilities located in various regions of the United States. Our merchant energy business also focuses on serving the energy and capacity requirements (load-serving) of, and providing other energy products and risk management services for, various customers.

BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of 10 counties in central Maryland. BGE was incorporated in Maryland in 1906.

Our other nonregulated businesses:

- design, construct, and operate renewable energy, heating, cooling, and cogeneration facilities, and provide various energy-related services, including energy consulting, for commercial, industrial, and governmental customers throughout North America,
- provide energy performance contracting and energy efficiency engineering services,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, provide natural gas marketing to residential customers in central Maryland, and, in 2010, began providing residential electric supply, and
- develop and deploy new nuclear plants in North America through our joint venture (UniStar Nuclear Energy, LLC) with a subsidiary of EDF Group.

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our nuclear generation and operation business, to EDF Group and affiliates (EDF) for total consideration of approximately $4.7 billion ($4.5 billion at close plus expense reimbursements). Our remaining 50.01% investment in CENG is an integral part of our nuclear business.

In connection with closing the transaction with EDF, we and EDF agreed to comply with certain conditions contained in an order from the Maryland Public Service Commission (Maryland PSC). We discuss these conditions in detail in *Item 7. Management's Discussion and Analysis—Business Environment—Regulation—Maryland*.

Prior to 2009, our merchant energy business included significant trading operations and an international commodities operation and grew rapidly. As that business grew, so too did its need for capital, particularly to fund the business' collateral requirements. We had previously met these collateral requirements through the use of cash and lines of credit, and we believed that we could meet any unexpected short-term capital needs by maintaining a significant amount of available liquidity, primarily from our unused credit facilities. Furthermore, by maintaining an investment grade credit rating, we believed we would continue to be able to access the capital markets if additional liquidity needs arose.

Therefore, as a capital- and asset-intensive business, Constellation Energy was significantly impacted by the events in the financial and credit markets during 2008. To address the liquidity issues arising from the credit and market events of 2008, we explored a series of strategic initiatives to improve our liquidity and reduce our business risk. During 2009, we completed transactions to sell our international commodities operation, our gas trading operation, our shipping joint venture, and our uranium market participant. These transactions helped improve our liquidity and reduce our business risk and resulted in substantial changes to our business in 2009. We discuss these transactions in more detail in *Note 2 to Consolidated Financial Statements*.

We plan to execute the following objectives that we believe will strengthen the Company:

- continuing a disciplined approach to the management of collateral and liquidity, including:
  - pricing new retail and wholesale business to reflect the full cost of capital in the current economic environment,
  - balancing operating cash flows with earnings growth,
  - maintaining a liquidity cushion in excess of credit-rating downgrade collateral requirements, and
  - aligning our load obligations by buying generation assets in regions where we do not have a significant generation presence,
- focusing on Constellation Energy's core strengths of:
  - owning, developing, and operating generation assets,
  - providing reliable, regulated utility service to customers,
  - leveraging our expertise in managing physical risks inherent in our Generation and Customer Supply operations, and
  - maintaining strong supply relationships with retail and wholesale customers,

- maintaining credit metrics consistent with investment grade ratings.

We believe that focusing on the above objectives will allow us to preserve the flexibility to respond to long-term opportunities. For a further discussion of the above matters and how they have impacted us and our strategy, please refer to *Item 7. Management's Discussion and Analysis—Strategy*.

Operating Segments

The percentages of revenues, net income (loss) attributable to common stock, and assets attributable to our operating segments are shown in the tables below. We present information about our operating segments, including certain other items, in *Note 3 to Consolidated Financial Statements*.

	Unaffiliated Revenues			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2009	75%	18%	5%	2%
2008	80	14	5	1
2007	83	12	4	1

	Net Income (Loss) Attributable to Common Stock (1)			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2009	98%	2%	1%	(1)%
2008	(103)	—	3	—
2007	83	12	3	2

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Holding Company and Other Nonregulated
2009	58%	21%	6%	15%
2008	62	21	6	11
2007	73	20	6	1

(1) *Excludes income from discontinued operations in 2007 as discussed in more detail in Item 8. Financial Statements and Supplementary Data.*

Merchant Energy Business

Introduction

Our merchant energy business generates and sells power and gas to both regulated and nonregulated wholesale and retail marketers and consumers of energy products, manages all commodity price risk for our nonregulated businesses, enters into structured energy contracts, and trades energy. We conduct these activities across the United States and Canada.

Our merchant energy business includes:

- a power generation and development operation that owns, operates, and maintains fossil and renewable generating facilities, and holds interests in qualifying facilities, a fuel processing facility and power projects in the United States,
- a nuclear generation operation that owns, operates, and maintains nuclear generating facilities (through November 6, 2009),
- nuclear generation operations through our membership interest in CENG, our nuclear joint venture (subsequent to November 6, 2009),
- a customer supply operation that primarily provides products and services to meet the energy requirements of wholesale and retail customers, including distribution utilities, cooperatives, aggregators, and commercial, industrial and governmental customers, and
- a commodities operation that manages contractually controlled physical assets, including generation facilities and natural gas properties, provides risk management services, and trades energy and energy-related commodities to facilitate portfolio management.

During 2009, our merchant energy business:

- supplied approximately 121 million megawatt hours (MWH) of aggregate load to distribution utilities, municipalities, and commercial, industrial, and governmental customers,
- provided approximately 350 million British Thermal Units (mmBTUs) of natural gas to commercial, industrial, and governmental customers,
- delivered approximately 13.5 million tons of coal to international and domestic third party customers and to our own fleet (we sold our international coal operations in the first quarter of 2009), and
- managed 7,118 megawatts (MW) of generation capacity as of December 31.

During 2009 and prior, we analyze our merchant energy business in terms of Generation, Customer Supply and Global Commodities activities.

- Generation—encompasses all of our generating assets.
- Customer Supply—encompasses our load-serving operation that provides energy products and services to wholesale and retail electric and natural gas customers.
- Global Commodities—encompasses our marketing, risk management, and trading operations, and upstream natural gas activities.

2010 Segments

As a result of our strategic initiatives completed in 2009 and the transformation of our business, our merchant energy business will become two separate reportable segments in 2010: Generation and Customer Supply.

Generation will consist of all of our generating assets, which include:

- a power generation and development operation that owns, operates, and maintains fossil and renewable generating facilities, a fuel processing facility, qualifying facilities, and power projects in the United States,
- an operation that manages certain contractually owned physical assets, including generating facilities,
- an interest in a nuclear generation joint venture that owns, operates, and maintains five nuclear generating units, and
- an interest in a joint venture to develop, own, and operate new nuclear projects in the United States.

Customer Supply will consist of the following:

- full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
- sales of retail energy products and services to commercial, industrial, and governmental customers,
- structured transactions and risk management services for various customers (including hedging the output from generating facilities and fuel costs) and trades energy and energy-related commodities to facilitate portfolio management,
- risk management services for our generation fleet assets,
- design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America, including energy performance contracting and energy efficiency engineering services,
- upstream (exploration and production) natural gas activities, and
- sales of home improvements, servicing of electric and gas appliances, and heating, air conditioning, plumbing, electrical, and indoor air quality systems, and providing electric and natural gas to residential customers in central Maryland.

Generation

We develop, own, operate, and maintain fossil and renewable generating facilities, hold a 50.01% interest in a nuclear joint venture that owns nuclear generating facilities, and hold interests in qualifying facilities, and power projects in the United States and Canada totaling 7,118 MW. The output of our owned and contractually-controlled plants is managed by our Global Commodities operation and is hedged through a combination of power sales to wholesale and retail market participants. We also provide operation and maintenance services, including testing and start-up, to owners of electric generating facilities. Our merchant energy business meets the load-serving requirements under various contracts using the output from our generating fleet and from purchases in the wholesale market.

We present details about our generating properties in *Item 2. Properties.*

Investment in Nuclear Generating Facilities

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG, our subsidiary that owns our nuclear generating facilities described below. The total output of these nuclear facilities over the past three years is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH (1)	Capacity Factor	MWH	Capacity Factor
			(MWH in millions)			
2009	14.5	96%	13.1	97%	4.6	91%
2008	14.7	96	12.8	94	4.7	94
2007	14.3	94	12.3	90	4.9	98

(1) Represents our and CENG's (after November 6, 2009) proportionate ownership interest

In connection with the closing of the transaction with EDF, on November 6, 2009, we entered into a power purchase agreement (PPA) with CENG, Under the terms of the PPA, we will purchase up to 90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing agreements over the five-year term of the PPA. We discuss this PPA in more detail in *Note 16 to Consolidated Financial Statements*.

Calvert Cliffs

CENG owns 100% of Calvert Cliffs Unit 1 and Unit 2. Unit 1 entered service in 1974 and is licensed to operate until 2034. Unit 2 entered service in 1976 and is licensed to operate until 2036.

Nine Mile Point

CENG owns 100% of Nine Mile Point Unit 1 and 82% of Unit 2. The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority (LIPA). Unit 1 entered service in 1969 and is licensed to operate until 2029. Unit 2 entered service in 1988 and is licensed to operate until 2046. The Nine Mile Point Unit 1 power purchase agreement with the former plant's owners ended in August 2009.

Nine Mile Point Unit 2 sells 90% of the plant's output to the former owners of the plant at an average price of nearly $35 per MWH under a PPA that terminates in November 2011. The PPA is unit contingent (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources). The remaining 10% of the output of Nine Mile Point Unit 2 is managed by CENG and sold into the wholesale market.

After termination of the Nine Mile Point Unit 2 PPA, a revenue sharing agreement with the former owners of the plant will begin and continue through November 2021. Under this agreement, which applies only to CENG's ownership percentage of Unit 2, a predetermined strike price is compared to the market price for electricity. If the market price exceeds the strike price, then 80% of this excess amount is shared with the former owners of the plant. The average strike price for the first year of the revenue sharing agreement is $40.75 per MWH. The strike price increases two percent annually beginning in the second year of the revenue sharing agreement. The revenue sharing agreement is unit contingent and is based on the operation of Unit 2.

CENG exclusively operates Unit 2 under an operating agreement with LIPA. LIPA is responsible for 18% of the operating costs (including decommissioning costs) and capital expenditures of Unit 2 and has representation on the Nine Mile Point Unit 2 management committee, which provides certain oversight and review functions.

Ginna

CENG owns 100% of the Ginna nuclear facility. Ginna entered service in 1970 and is licensed to operate until 2029. Ginna sells approximately 90% of the plant's output and capacity to the former owner for 10 years ending in 2014 at an average price of $44.00 per MWH under a long-term unit-contingent PPA. The remaining 10% of the output of Ginna is managed by CENG and sold into the wholesale market.

Qualifying Facilities and Power Projects

We hold up to a 50% voting interest in 18 operating energy projects, totaling approximately 771 MW, that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities. Sixteen of the electric generation projects are considered qualifying facilities under the Public Utility Regulatory Policies Act of 1978. Each electric generating plant sells its output to a local utility under long-term contracts.

Customer Supply

We are a leading supplier of energy products and services to wholesale and retail electric and natural gas customers.

In 2009, our wholesale customer supply operation served approximately 65 million peak MWHs of wholesale full requirements load-serving products. During 2009, our retail customer supply activities served approximately 56 million MWHs of peak load and approximately 350 mmBTUs of natural gas.

Our wholesale customer supply operation structures transactions that serve the full energy and capacity requirements of various customers such as distribution utilities, municipalities, cooperatives and retail aggregators that do not own sufficient generating capacity or in-house supply functions to meet their own load requirements.

Our retail customer supply operation structures transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to retail, commercial, industrial, and governmental customers. Contracts with these customers generally extend from one to ten years, but some can be longer.

To meet our customers' requirements, our merchant energy business obtains energy from various sources, including:

- our generation assets,
- our leased generation assets,
- exchange-traded and bilateral power and natural gas purchase agreements,
- unit contingent power purchases from generation companies,
- tolling contracts with generation companies, which provide us the right, but not the obligation, to purchase power at a price linked to the variable cost of production, including fuel, with terms that generally extend from several months to several years, but can be longer, and
- regional power pools.

Global Commodities

Our Global Commodities operation manages contractually owned physical assets, including generation facilities, and natural gas properties, provides risk management services, and trades energy and energy-related commodities. This operation provides the wholesale risk management function for our Generation and Customer Supply operations, as well as structured products and energy investment activities and includes our merchant energy business' actual hedged positions with third parties.

Structured Products

Our Global Commodities operation uses energy and energy-related commodities and contracts in order to manage our portfolio of energy purchases and sales to customers through structured transactions. Our Global Commodities operation assists customers with customized risk management products in the power, gas, coal, and freight markets (e.g., generation tolls, gas transport and storage, and global coal and freight logistics). During 2009, we reduced our participation in the coal, freight, and gas trading markets through the completion of the divestitures of our international commodities and Houston-based gas trading operations. We discuss our 2009 divestitures in more detail in *Note 2 to Consolidated Financial Statements*.

Energy Investments

Our Global Commodities operation has investments in energy assets that primarily include natural gas activities. During 2009, we sold our previous investments in coal sourcing activities as well as our interest in dry bulk cargo vessels. We discuss each of these investments below.

Coal and International Services

We participated in global coal sourcing activities by providing coal and coal-related logistical services for the variable or fixed supply needs of global customers. We sold this operation in March 2009. We also owned a 50% interest in a shipping joint venture that owned and operated five freight ships for the delivery of coal and other dry bulk freight products. We sold our 50% interest in this shipping joint venture to our partner during 2009.

Natural Gas Services

Our Global Commodities operation includes upstream (exploration and production) and downstream (transportation and storage) natural gas operations. Our upstream activities include the development, exploration, and exploitation of natural gas properties, as well as an approximately 28.5% interest in Constellation Energy Partners LLC (CEP), a limited liability company that we formed. CEP is principally engaged in the acquisition, development, and exploitation of natural gas properties. We no longer have any active involvement in the day-to-day operations of CEP. Our Houston-based downstream activities included providing natural gas to various customers, including large utilities, commercial and industrial customers, power generators, wholesale marketers, and retail aggregators. We sold our Houston-based downstream activities during 2009.

Portfolio Management and Trading

Our Global Commodities operation transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. We use economic value at risk, which measures the market risk in our total portfolio, encompassing all aspects of our merchant energy business, along with daily value at risk, stop loss limits, position limits, generation hedge ratios, and liquidity guidelines to restrict the level of risk in our portfolio.

In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

We use both derivative and nonderivative contracts in managing our portfolio of energy sales and purchase contracts. Although a substantial portion of our portfolio is hedged, we are able to identify opportunities to deploy risk capital to increase the value of our accrual positions, which we characterize as portfolio management.

Active portfolio management is intended to allow our merchant energy business to:

- manage and hedge its fixed-price energy purchase and sale commitments,
- provide fixed-price energy commitments to customers and suppliers,
- reduce exposure to the volatility of market prices, and
- hedge fuel requirements at our non-nuclear generation facilities.

We discuss the impact of our trading activities and economic value at risk in more detail in *Item 7. Management's Discussion and Analysis.*

Our portfolio management and trading activities involve the use of physical commodity inventories and a variety of instruments, including:

- forward contracts (which commit us to purchase or sell energy commodities in the future),
- swap agreements (which require payments to or from counterparties based upon the difference between two prices for a predetermined contractual (notional) quantity),
- option contracts (which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price), and
- futures contracts (which are exchange traded standardized commitments to purchase or sell a commodity or financial instrument, or make a cash settlement, at a specified price and future date).

Beginning in the fourth quarter of 2008 and continuing throughout 2009, we reduced the risk and scale of our portfolio management and trading activities. Energy trading activities were scaled back and are being used primarily for hedging our generation assets and Customer Supply operations, price discovery and verification, and for deploying limited risk capital. These efforts materially impacted our portfolio management and trading activities' contribution to our operating results.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2009 and owned generation based on actual output by fuel type in 2009 were as follows:

Fuel	Capacity Owned	Generation
Nuclear (1)	27%	65%
Coal	38	30
Natural Gas	13	1
Oil	10	—
Renewable and Alternative (2)	6	4
Dual (3)	6	—

(1) *Reflects our 100% ownership through November 6, 2009 and 50.01% ownership from November 6, 2009 through December 31, 2009 following the sale of a 49.99% membership interest in our nuclear business on November 6, 2009.*

(2) *Includes solar, geothermal, hydro, waste coal, and biomass.*

(3) *Switches between natural gas and oil.*

We discuss our risks associated with fuel in more detail in *Item 7. Management's Discussion and Analysis—Risk Management.*

Nuclear

CENG, our nuclear joint venture with EDF, owns the Calvert Cliffs, Nine Mile Point, and Ginna nuclear generating facilities.

The supply of fuel for these nuclear generating facilities includes the:

- purchase of uranium (concentrates and uranium hexafluoride),
- conversion of uranium concentrates to uranium hexafluoride,
- enrichment of uranium hexafluoride (enrichment services and enriched uranium hexafluoride), and
- fabrication of nuclear fuel assemblies.

CENG has commitments that provide for quantities of uranium, conversion, enrichment, and fabrication of fuel assemblies to substantially meet expected requirements for the next several years at these nuclear generating facilities.

The uranium markets are competitive, and while prices can be volatile, CENG does not anticipate problems in meeting its future supply requirements.

Storage of Spent Nuclear Fuel—Federal Facilities

One of the issues associated with the operation and decommissioning of nuclear generating facilities is disposal of spent nuclear fuel. There are no facilities for the reprocessing or permanent disposal of spent nuclear fuel currently in operation in the United States, and the Nuclear Regulatory Commission (NRC) has not licensed any such facilities. The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government, through the Department of Energy (DOE), to develop a repository for the disposal of spent nuclear fuel and high-level radioactive waste.

As required by the NWPA, CENG is a party to contracts with the DOE to provide for disposal of spent nuclear fuel from our nuclear generating plants. The NWPA and CENG's contracts with the DOE require payments to the DOE of one tenth of one cent (one mill) per kilowatt hour on nuclear electricity generated and sold to pay for the cost of long-term nuclear fuel storage and disposal. Through November 6, 2009, we paid those fees into the DOE's Nuclear Waste Fund and, for the remainder of 2009, CENG has paid these fees for the Calvert Cliffs, Nine Mile Point and Ginna nuclear generating facilities. The NWPA and CENG's contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998.

The DOE has stated that it may not meet that obligation until 2020 at the earliest. This delay has required that CENG undertake additional actions and incur costs to provide on-site fuel storage at its nuclear generating facilities, including the installation of on-site dry fuel storage capacity as described in more detail below.

In 2004, complaints were filed against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. These cases are currently stayed, pending litigation in other related cases. We are entitled to any funds received from the DOE that reimburse any costs expended prior to the closing of the transaction with EDF for the storage of spent nuclear fuel. Any other funds received from the DOE representing the default by the DOE shall belong to CENG.

Storage of Spent Nuclear Fuel—On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. Sufficient storage capacity exists within the plant and currently installed independent spent fuel storage installation modules to be able to contain the full contents of the core until 2015. Efforts are currently under way to renew the independent spent fuel installation license and expand its capacity to accommodate operations through 2036. Nine Mile Point and Ginna are developing independent spent fuel storage installations at each of those facilities, which are expected to be completed in 2012 and 2010, respectively. Nine Mile Point and Ginna have sufficient storage capacity within the plant until the expected completion of the on-site independent spent fuel storage installations.

Cost for Decommissioning Nuclear Facilities

When Constellation Energy sold a 49.99% membership interest in CENG on November 6, 2009, we deconsolidated CENG for financial reporting purposes and, as a result, the decommissioning trust funds were removed from our Consolidated Balance Sheets. CENG is obligated to decommission its nuclear power plants after these plants cease operation. The nuclear decommissioning trust funds and the investment earnings thereon are restricted to meeting the costs of decommissioning the plants in accordance with NRC regulations and relevant state requirements. The decommissioning trust fund strategy is based on estimates of the costs to perform the decommissioning and the timing of incurring those costs. When developing estimates of future fund earnings, CENG considered the asset allocation investment strategy, rates of return earned historically, and current market conditions.

Decommissioning activities are currently projected to be staged through 2083. Any changes in the costs or timing of decommissioning activities, or changes in the fund earnings, could affect the adequacy of the funds to cover the decommissioning of the plants, and if there were to be a shortfall, additional funding would have to be provided.

Calvert Cliffs

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Public Service Commission of Maryland (Maryland PSC), and certain State of Maryland officials. The settlement agreement became effective on June 1, 2008. Pursuant to the terms of the settlement agreement, BGE customers will be relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1 which was enacted in June 2006.

Coal

We purchase the majority of our coal for electric generation under supply contracts with mine operators, and we acquire the remainder in the spot or forward coal markets. We believe that we will be able to renew supply contracts as they expire or enter into contracts with other coal suppliers. Our primary coal-burning facilities have the following requirements:

	Approximate Annual Coal Requirement (tons)
Brandon Shores—Units 1 and 2 (combined)	3,200,000
C. P. Crane—Units 1 and 2 (combined) (1)	1,200,000
H. A. Wagner—Units 2 and 3 (combined)	850,000

(1) *Assuming 100% sub-bituminous coal*

We receive coal deliveries to these facilities by rail and barge. Over the past few years, we expanded our coal sources through a variety of methods, including restructuring our rail and terminal contracts, increasing the range of coals we can consume, and finding potential other coal supply sources including limited shipments from various international sources. While we primarily use coal produced from mines located in central and northern Appalachia, we are switching to sub-bituminous coal from either the Western United States or Indonesia at C.P. Crane and have the ability to switch to using imported coal at Brandon Shores and H.A. Wagner to manage our coal supply. The timely delivery of coal together with the maintenance of appropriate levels of inventory is necessary to allow for continued, reliable generation from these facilities.

As discussed in the *Environmental Matters* section, our Maryland coal-fired generating facilities must comply with the requirements of the Maryland Healthy Air Act (HAA), which requires reduction of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emissions. To comply with the HAA requirements, we are planning to burn domestic and/or import compliance coals (1.2 lb/mmbtu SO_2 or less) at H.A. Wagner. The C.P. Crane station is being converted to burn up to 100% sub-bituminous coal. Conversion is expected to be completed by May 2010. We are installing flue gas desulfurization (FGD) equipment on both Brandon Shores units. Installation is expected to be completed in March 2010. With the FGD installation, Brandon Shores will be able to burn higher sulfur coals (limit 6 lbs/mmbtu or approximately 3.5% sulfur) while simultaneously reducing station emissions. We plan to test burn some higher sulfur coals at Brandon Shores in 2010. The blend of coals actually procured for Brandon Shores will be optimized to achieve the lowest delivered cost while complying with HAA limitations.

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh.

All of the Conemaugh and Keystone plants' annual coal requirements are purchased from regional suppliers on the open market. FGD equipment was installed on both of the Keystone units in 2009 and has been installed on both Conemaugh units since the mid-1990s. The FGD SO_2 restrictions on coal are 6 lbs/mmbtu (or approximately 3.7% sulfur) for the Keystone plant and approximately 4.9 lbs/mmbtu (or 3% sulfur) for the Conemaugh plant. The blend of coal procured is optimized to ensure compliance with station emission limits at the lowest delivered cost.

The annual coal requirements for the ACE, Jasmin, and Poso plants, which are located in California, are supplied under contracts with mining operators. These plants are restricted to coal with sulfur content less than 4.0%.

The primary fuel source for Panther Creek and Colver generating facilities is waste coal. These facilities meet their annual requirements through existing reserves of mined and processed waste coal and through supply agreements with various terms.

All of our coal requirements reflect historical generating levels. The actual fuel quantities required can vary substantially from historical levels depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of coal to meet our requirements.

Gas

We purchase natural gas, storage capacity, and transportation, as necessary, for electric generation at certain plants. Some of our gas-fired units can use residual fuel oil or distillates instead of gas. Gas is purchased under contracts with suppliers on the spot market and forward markets, including financial exchanges and under bilateral agreements. The actual fuel quantities required can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of gas to meet our requirements.

Oil

From 2007 through 2009, our requirements for residual fuel oil (No. 6) amounted to less than 0.5 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor and Philadelphia marine terminals for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 8.0 million to 11.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

We encounter competition from companies of various sizes, having varying levels of experience, financial and human resources, and differing strategies.

We face competition in the market for energy, capacity, and ancillary services. In our merchant energy business, we compete with international, national, and regional full-service energy providers, merchants, and producers to obtain competitively priced supplies from a variety of sources and locations, and to utilize efficient transmission, transportation, or storage. We principally compete on the basis of price, customer service, reliability, and availability of our products.

With respect to power generation, we compete in the operation of energy-producing projects, and our competitors in this business are both domestic and international organizations, including various utilities, industrial companies and independent power producers (including affiliates of utilities, financial investors, and banks), some of which have greater financial resources.

States are considering different types of regulatory initiatives concerning competition in the power and gas industry, which makes a competitive assessment difficult. Many states continue to support or expand retail competition and industry restructuring. Other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, restructured states often consider new market rules and re-regulation measures that could result in more limited opportunities for competitive energy suppliers like Constellation Energy. The activity around re-regulation, however, has slowed due to the current environment of declining power prices. While there is activity in this area, we believe there is adequate growth potential in the current deregulated market.

The market for commercial, industrial, and governmental energy supply continues to grow and we continue to experience increased competition from energy and non-energy market participants on a regional and national basis in our retail customer supply activities. Strong retail competition and the impact of wholesale power prices compared to the rates charged by local utilities affects the contract margin we receive from our customers. The recent credit crisis has increased overall margins reflecting an appropriate return on capital to support the business. Our experience and expertise in assessing and managing risk and our strong focus on customer service should help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

	2009	2008	2007
Gross Margin *(In millions)*			
Generation*	**$1,976**	$1,919	$1,698
Customer Supply	**799**	765	889
Global Commodities	**185**	215	648
Total Gross Margin	**$2,960**	$2,899	$3,235
Generation *(In millions)*—MWH *	**46.0**	50.9	51.6

Operating statistics do not reflect the elimination of intercompany transactions.

* *2009 reflects our 100% ownership in our nuclear business through November 6, 2009 and our 50.01% ownership in our nuclear business from November 6, 2009 through December 31, 2009 following the sale of a 49.99% membership interest in CENG.*

Baltimore Gas and Electric Company

BGE is an electric transmission and distribution utility company and a gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. BGE is regulated by the Maryland PSC and Federal Energy Regulatory Commission (FERC) with respect to rates and other aspects of its business.

BGE's electric service territory includes an area of approximately 2,300 square miles. There are no municipal or cooperative wholesale customers within BGE's service territory. BGE's gas service territory includes an area of approximately 800 square miles.

BGE's electric and gas revenues come from many customers—residential, commercial, and industrial.

Electric Business

Electric Competition

Deregulation

Maryland has implemented electric customer choice and competition among electric suppliers. As a result, all customers can choose their electric energy supplier. While BGE does not sell electricity to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance.

Standard Offer Service

BGE is obligated by the Maryland PSC to provide market-based standard offer service (SOS) to all of its electric customers who elect not to select a competitive energy supplier. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component. As discussed in *Item 7. Management's Discussion and Analysis—Regulated Electric Business* section, BGE resumed collection of the shareholder return portion of the residential SOS administrative charge, which had been eliminated under Maryland Senate Bill 1, from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. BGE will cease collecting the residential shareholder return component again from June 1, 2010 through December 31, 2016.

Bidding to supply BGE's SOS occurs from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, execute contracts with BGE for varying terms.

Commercial and Industrial Customers

BGE is obligated by the Maryland PSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Residential Customers

As a result of the November 1999 Maryland PSC order regarding the deregulation of electric generation in Maryland, BGE's residential electric base rates were frozen until July 2006. However, Maryland Senate Bill 1, enacted in June 2006, delayed full market rates for some residential customers until June 2007, with the remainder of residential customers going to full market rates in January 2008. Pursuant to a settlement agreement entered into with the State of Maryland, the Maryland PSC, and certain Maryland officials in March 2008, BGE provided residential electric customers approximately $189 million in the form of a one-time $170 per customer rate credit. We discuss the Maryland settlement agreement in more detail in *Note 2 to Consolidated Financial Statements* and the market risk of our regulated electric business in more detail in *Item 7. Management' Discussion and Analysis—Risk Management* section.

Pursuant to the order issued by the Maryland PSC in October 2009 approving our transaction with EDF, Constellation Energy agreed to fund a one-time per customer distribution rate credit for BGE residential customers, before the end of March 2010, totaling

$110.5 million, or approximately $100 per customer, for which we recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating we would give residential customers a rate credit of exactly $100 per customer. As a result, we accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. Constellation made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as required by the Maryland PSC order.

Electric Load Management

BGE has implemented various programs for use when system-operating conditions or market economics indicate that a reduction in load would be beneficial. These programs include:

- two options for commercial and industrial customers to reduce their electric loads,
- air conditioning and heat pump control for residential and commercial customers through both programmable thermostats and load control devices, and
- residential water heater control.

BGE is developing other programs designed to help manage its peak demand, improve system reliability and improve service to customers by giving customers greater control over their energy use.

In July 2009, BGE filed with the Maryland PSC a proposal for a comprehensive smart grid initiative. The proposal includes the planned installation of 2 million residential and commercial electric and gas smart meters. We expect the total cost of the program to be approximately $480 million. In October 2009, the United States Department of Energy selected BGE as a recipient of $200 million in federal funding for our smart grid initiative. This grant allows BGE to be reimbursed for smart grid expenditures up to $200 million, substantially reducing the total cost of this initiative. However, the United States Department of Energy may withhold funding until approval is obtained from the Maryland PSC. The Maryland PSC held hearings on this proposed program in late 2009 and early 2010 and expects to issue a ruling in the second quarter of 2010. If BGE's proposal is approved by the Maryland PSC, BGE plans to proceed with this program as soon as practical.

In the summer of 2009, BGE conducted a second season of a pilot program to evaluate pricing options designed to encourage customers to decrease energy use during peak demand periods. Additionally, BGE originally initiated a limited conservation program that provides incentives to customers to use energy efficient products and to take other actions to conserve energy. The Maryland PSC approved a full portfolio of conservation programs for implementation in 2009 as well as a customer surcharge to recover the associated costs.

Transmission and Distribution Facilities

BGE maintains approximately 240 substations and approximately 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 24,500 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of PJM Interconnection (PJM). Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity, and ancillary services transactions, including emergency assistance.

We discuss various FERC initiatives relating to wholesale electric markets in more detail in *Item 7. Management's Discussion and Analysis—Federal Regulation* section.

BGE Electric Operating Statistics

	2009	2008	2007
Revenues *(In millions)*			
Residential	**$1,878.3**	$1,695.9	$1,514.9
Commercial			
Excluding Delivery Service Only	**531.2**	604.0	577.4
Delivery Service Only	**245.0**	222.8	217.0
Industrial			
Excluding Delivery Service Only	**30.4**	31.3	31.6
Delivery Service Only	**29.1**	27.1	27.8
System Sales and Deliveries	**2,714.0**	2,581.1	2,368.7
Other (1)	**106.7**	98.6	87.0
Total	**$2,820.7**	$2,679.7	$2,455.7
Distribution Volumes *(In thousands)*—MWH			
Residential	**12,851**	13,023	13,365
Commercial			
Excluding Delivery Service Only	**3,945**	3,957	4,364
Delivery Service Only	**11,753**	11,739	11,921
Industrial			
Excluding Delivery Service Only	**270**	242	287
Delivery Service Only	**2,757**	3,002	3,175
Total	**31,576**	31,963	33,112
Customers *(In thousands)*			
Residential	**1,111.9**	1,108.5	1,103.1
Commercial	**118.5**	117.6	116.7
Industrial	**5.3**	5.3	5.5
Total	**1,235.7**	1,231.4	1,225.3

(1) Primarily includes network integration transmission service revenues, late payment charges, miscellaneous service fees, and tower leasing revenues.

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of electricity that was purchased by the customer from an alternate supplier.

Gas Business

The wholesale price of natural gas as a commodity is not subject to regulation. All BGE gas customers have the option to purchase gas from alternative suppliers, including subsidiaries of Constellation Energy. BGE continues to deliver gas to all customers within its service territory. This delivery service is regulated by the Maryland PSC.

BGE also provides customers with meter reading, billing, emergency response, regular maintenance, and balancing services.

Approximately 50% of the gas delivered on BGE's distribution system is for customers that purchase gas from alternative suppliers. These customers are charged fees to recover the costs BGE incurs to deliver the customers' gas through our distribution system.

A market-based rates incentive mechanism applies to customers that buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. Additionally, in 2009, the Maryland PSC required BGE to obtain some of its summer gas purchases for injection into storage at fixed prices. BGE purchased approximately 5.9 million dekatherms (DTH) of gas for summer storage injections under fixed price contracts with a weighted average price of $4.61 per DTH. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements.

BGE's current pipeline firm transportation entitlements to serve its firm loads are 338,053 DTH per day.

BGE's current maximum storage entitlements are 297,091 DTH per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,092,977 DTH and a daily capacity of 311,500 DTH, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 564,200 DTH and a daily capacity of 85,000 DTH.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods.

BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

BGE Gas Operating Statistics

	2009	2008	2007
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 460.7**	$ 567.8	$ 552.0
Delivery Service Only	**19.0**	19.0	19.0
Commercial			
Excluding Delivery Service Only	**129.1**	161.8	154.1
Delivery Service Only	**40.4**	46.4	41.2
Industrial			
Excluding Delivery Service Only	**6.4**	8.1	7.8
Delivery Service Only	**15.2**	14.5	22.1
System Sales and Deliveries	**670.8**	817.6	796.2
Off-System Sales	**81.1**	197.7	157.4
Other	**6.4**	8.7	9.2
Total	**$ 758.3**	$ 1,024.0	$ 962.8
Distribution Volumes *(In thousands)*—DTH			
Residential			
Excluding Delivery Service Only	**37,889**	37,675	39,199
Delivery Service Only	**4,270**	4,119	4,310
Commercial			
Excluding Delivery Service Only	**12,066**	12,205	12,464
Delivery Service Only	**25,046**	29,289	30,367
Industrial			
Excluding Delivery Service Only	**635**	650	658
Delivery Service Only	**20,826**	18,432	17,897
System Sales and Deliveries	**100,732**	102,370	104,895
Off-System Sales	**17,542**	18,782	19,963
Total	**118,274**	121,152	124,858
Customers *(In thousands)*			
Residential	**606.8**	605.0	602.3
Commercial	**42.9**	42.8	42.7
Industrial	**1.1**	1.1	1.2
Total	**650.8**	648.9	646.2

Operating statistics do not reflect the elimination of intercompany transactions.
"Delivery service only" refers to BGE's delivery of gas that was purchased by the customer from an alternate supplier.

Franchises

BGE has nonexclusive electric and gas franchises to use streets and other highways that are adequate and sufficient to permit it to engage in its present business. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

New Nuclear

In 2005, we formed UniStar Nuclear, LLC (UniStar), a joint enterprise with AREVA NP, Inc., (AREVA) to introduce the advanced design Evolutionary Power Reactor to the U.S. market. Upon conversion to U.S. electrical standards, the technology will be known as the U.S. EPR.

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UNE) with EDF. We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. EDF initially invested $350 million of cash in UNE, and we contributed our interest in UniStar and other UniStar-related assets, which had a book value of $49 million, and the right to develop new nuclear projects at our existing nuclear plant locations. In the event that the joint venture is terminated, the remaining equity of UNE, after certain expenses, will be divided equally between Constellation Energy and EDF pursuant to the joint venture agreement.

In 2008, EDF contributed an additional $175 million to UNE based upon reaching certain licensing milestones. EDF will contribute up to an additional $100 million to UNE, for a total of $625 million, upon reaching additional licensing milestones. In 2008, we contributed additional assets which had a book value of $2.0 million.

In 2009, we and EDF have each contributed an additional $91.6 million to UNE to fund its capital requirements.

Beginning on January 1, 2010, UNE's results of operations and financial condition will become part of our Generation reportable segment.

Energy Projects and Services

We offer energy projects and services to large commercial, industrial and governmental customers. These energy products and services include:

- designing, constructing, and operating renewable energy, heating, cooling, and cogeneration facilities,
- energy performance contracting and energy efficiency engineering services,
- water and energy savings projects and performance contracting,
- energy consulting and procurement services,
- services to enhance the reliability of individual electric supply systems, and
- customized financing alternatives.

Beginning on January 1, 2010, our Energy Projects and Services operation's results of operations and financial condition will become part of our Customer Supply reportable segment.

Home Products and Retail Marketing

We offer services to customers in Maryland including:

- home improvements,
- the service of heating, air conditioning, plumbing, electrical, and indoor air quality systems, and
- the sale of electricity and natural gas to residential customers.

Beginning on January 1, 2010, our Home Products and Gas Retail Marketing operation's results of operations and financial condition will become part of our Customer Supply reportable segment.

Consolidated Capital Requirements

Our total capital requirements for 2009 were $1.6 billion. Of this amount, $1.2 billion was used in our nonregulated businesses and $0.4 billion was used in our regulated business. We estimate our total capital requirements will be $1.1 billion in 2010.

We continuously review and change our capital expenditure programs, so actual expenditures may vary from the estimate above. We discuss our capital requirements further in *Item 7. Management's Discussion and Analysis—Capital Resources* section.

Environmental Matters

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of development to the ongoing operation of existing or new electric generating and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, protection of natural and cultural resources, and chemical and waste handling and disposal.

We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance. Our capital expenditures were approximately $1.1 billion during the five-year period 2005-2009 to comply with existing environmental standards and regulations, including the Maryland HAA. Our estimated environmental capital requirements for the next three years are approximately $60 million in 2010, $25 million in 2011, and $35 million in 2012.

Air Quality

Federal

The Clean Air Act (CAA) created the basic framework for federal and state regulation of air pollution.

National Ambient Air Quality Standards (NAAQS)

The NAAQS are federal air quality standards authorized under the CAA that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, SO_2, and nitrogen dioxide.

In order for states to achieve compliance with the NAAQS, the Environmental Protection Agency (EPA) adopted the Clean Air Interstate Rule (CAIR) in March 2005 to further reduce ozone and fine particulate pollution by addressing the interstate transport of SO_2 and NO_x emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States.

In December 2008, the United States Court of Appeals for the District of Columbia Circuit reversed its July 2008 decision to effectively repeal CAIR and remanded the issue to the EPA for reconsideration. As a result, the requirements of CAIR remain in effect until the EPA takes further action. We cannot predict what additional judicial, legislative or regulatory actions will be taken in response to the court's decision or the EPA's reconsideration of CAIR or whether such actions may affect our financial results. We do not believe that the repeal of CAIR would result in a material change to our emissions reduction plan in Maryland as the emissions reduction requirements of Maryland's HAA and Clean Power Rule (CPR) are more stringent and apply sooner than those under CAIR. However, future changes in CAIR could affect the market prices of SO_2 and NO_x

emission allowances, which could in turn affect our financial results. We discuss the impact that these rulings had on our 2008 results in *Item 7. Management's Discussion and Analysis—Merchant Energy Business* section.

In March 2008, the EPA adopted a stricter NAAQS for ozone. We are unable to determine the impact that complying with the stricter NAAQS for ozone will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standards.

In December 2006, the United States Court of Appeals for the District of Columbia Circuit ruled that a requirement to impose fees on emissions sources based on the previous ozone standard (Section 185 fees), which had been rescinded by the EPA in May 2005, remained applicable retroactive to November 2005 and remanded the issue to the EPA for reconsideration. A petition to the United States Supreme Court to hear an appeal was denied in January 2008. The EPA has announced that it intends to propose regulations to address how Section 185 fees will be handled. In addition, the exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been proposed. Consequently, we are unable to estimate the ultimate financial impact of this matter in light of the uncertainty surrounding the anticipated EPA and state rulemakings. However, the final resolution of this matter, and any fees that are ultimately assessed could have a material impact on our financial results.

In September 2006, the EPA adopted a stricter NAAQS for particulate matter. We are unable to determine the impact that complying with the stricter NAAQS for particulate matter will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard.

Hazardous Air Emissions

In March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap and trade program. CAMR was to affect all coal or waste coal fired boilers at our generating facilities. However, in February 2008, the United States Court of Appeals for the District of Columbia Circuit struck down CAMR. In response to this decision, the EPA announced that it intends to develop new hazardous air pollutant emission standards under the CAA by the end of 2011. Any new standards that require the installation of additional emissions control technology beyond what is required under Maryland's HAA and CPR, which are discussed below, may require us to incur additional costs, which could have a material effect on our financial results.

New Source Review

In connection with its enforcement of the CAA's new source review requirements, in 2000, the EPA requested information relating to modifications made to our Brandon Shores, C.P. Crane, and H. A. Wagner plants located in Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants in which we have an ownership interest. We responded to the EPA in 2001, and as of the date of this report the EPA has taken no further action.

As discussed in *Note 12 to Consolidated Financial Statements*, in January 2009, the EPA issued a Notice of Violation to one of our subsidiaries alleging that the Keystone plant located in Pennsylvania, of which we own a 21% interest, performed various capital projects without complying with the new source review requirements.

Based on the level of emissions control that the EPA and states are seeking in new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

State

Maryland has adopted the HAA and the CPR, which establish annual SO_2, NO_x, and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The requirements of the HAA and the CPR for SO_2, NO_x, and mercury emissions are more stringent and apply sooner than those required under CAIR. In addition, Pennsylvania had adopted regulations requiring coal-fired generating facilities located in Pennsylvania to reduce mercury emissions, but a Pennsylvania court held that those regulations were invalid in January 2009.

Several other states in the northeastern U.S. continue to consider more stringent and earlier SO_2, NO_x, and mercury emissions reductions than those required under CAIR and CAMR.

Maryland also is in the process of changing its current opacity regulations consistent with its commitment to resolve long-standing industry concerns about the regulations' continuous compliance requirements. In the interim, emergency opacity regulations have been implemented that will enable our plants to remain in compliance. We anticipate that the permanent regulations that Maryland is in the process of adopting will be consistent with the emergency regulations.

Capital Expenditure Estimates—Air Quality

We expect to incur additional environmental capital spending as a result of complying with the air quality laws and regulations discussed above. To comply with

HAA and CPR, we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at our co-owned coal-fired facilities in Pennsylvania to meet air quality standards. We include in our estimated environmental capital requirements capital spending for these air quality projects, which we expect will be approximately $20 million in 2010, $20 million in 2011, $20 million in 2012 and $20 million from 2013-2014.

Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, such as any regulations adopted by the EPA in response to the court decision striking down CAMR, the implementation timetables for such regulation or legislation, and the specific amount of emissions reductions that will be required at our facilities. As a result, we cannot predict our capital spending or the scope or timing of these projects with certainty, and the actual expenditures, scope, and timing could differ significantly from our estimates.

We believe that the additional air emission control equipment we plan to install will meet the emission reduction requirements under HAA and CPR. If additional emission reductions still are required, we will assess our various compliance alternatives and their related costs, and although we cannot yet estimate the additional costs we may incur, such costs could be material.

Global Climate Change

In response to the anticipated challenges of global climate change, we believe it is imperative to slow, stop and reverse the growth in greenhouse gas emissions. Climate change could pose physical risks, such as more frequent or more extreme weather events, that could affect our systems and operations; however, uncertainty remains as to the timing and extent of any direct, climate-related impacts to our systems and operations. Extreme weather can affect the supply of and demand for electricity, natural gas and fuels and these changes may impact the price of energy commodities in both the spot market and the forward market, which may affect our financial results. In addition, extreme weather typically increases demand for electricity and gas from BGE's customers.

There is increasing likelihood that greenhouse gas emissions regulation will occur at the international or federal level and/or continue to occur at the state level although considerable uncertainty remains as to the nature and timing of such regulation. Climate-related legislation is currently pending in the United States Congress. In September 2009, the Environmental Protection Agency issued an "endangerment and cause or contribute finding" for greenhouse gases under the Clean Air Act and proposed regulations to address greenhouse gas emissions. The proposed regulations would require large facilities that emit at least 25,000 tons of greenhouse gases a year, which would include many of our fossil fuel generating facilities, to obtain construction and operating permits covering these emissions. The proposed regulations could also eventually require installation of best available control technology for emissions control or reduction, although it is not possible to determine at this time the nature or extent of such controls.

Additionally, in accordance with HAA requirements, Maryland became a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI) in April 2007. Under RGGI, the Maryland Department of the Environment auctions 100% of carbon dioxide (CO_2) allowances associated with Maryland's power plants, which include plants owned by us. Auctions have occurred quarterly since September 2008. Although we did not incur material costs in these auctions, we could incur material costs in the future to purchase allowances necessary to offset CO_2 emissions from our plants. Although we participate in RGGI, we believe a patchwork of climate policy and regulatory approaches across different states, regions or industry sectors has the potential to inequitably raise costs to particular businesses and/or drive the reallocation of emissions without actually achieving the desired overall reduction of emissions. In addition to Maryland, California has adopted regulations requiring our generating facilities in California to submit greenhouse gas emissions data to the state, which the state intends to use to develop a plan to reduce greenhouse gas emissions.

We continue to monitor international developments and proposed federal and state legislation and regulations and evaluate the potential impact on our operations. In the event that additional greenhouse gas emissions reduction legislation or regulations are enacted, we will assess our various compliance alternatives, which may include installation of additional environmental controls, modification of operating schedules or the closure of one or more of our coal-fired generating facilities, and our compliance costs could be material.

However, to the extent greenhouse gas emissions are regulated through a federal, mandatory cap and trade greenhouse gas emissions program, we believe our business could also benefit. Our generation fleet has an overall CO_2 emission rate that is lower than the industry average with a substantial amount of the fleet's output coming from nuclear and hydroelectric plants, which generate significantly lower CO_2 emissions than fossil fuel plants. We are also at the forefront of the proposed development of new nuclear generation in the United States, which, if successful, would further lower our generation fleet's overall CO_2 emission rate. We also have experience trading in the markets for emissions allowances and renewable energy credits and our Customer Supply operation has expertise in providing renewable energy products and services to retail customers.

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control and requires facilities that discharge waste or storm water into the waters of the United States to obtain permits.

Water Intake Regulations

The Clean Water Act requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. In July 2004, the EPA published final rules under the Clean Water Act for existing facilities that establish performance standards for meeting the best technology available for minimizing adverse environmental impacts. We currently have seven facilities affected by the regulation. In January 2007, the United States Court of Appeals for the Second Circuit ruled that the EPA's rule did not properly implement the Clean Water Act requirements in a number of areas and remanded the rule to the EPA for reconsideration.

In response to this ruling, in July 2007, the EPA suspended the second phase of the regulations pending further rulemaking and directed the permitting authorities to establish controls for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impacts. In December 2008, the United States Supreme Court heard an appeal of the Second Circuit's decision relating to the application of cost-benefit analysis to best technology available decisions and ruled in April 2009 that the EPA has a right to consider cost-benefit analysis in such decisions.

The EPA is expected to propose new regulations in mid-2010. We will evaluate our compliance options in light of the Supreme Court and Second Circuit decisions, the EPA's July 2007 order, relevant state regulations and interpretations, and any subsequent EPA proposals. At this time, we cannot estimate our compliance costs, but they could be material.

Hazardous and Solid Waste

We discuss proceedings relating to compliance with the Comprehensive Environmental Response, Compensation and Liability Act in *Note 12 to Consolidated Financial Statements*.

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year. The EPA announced in 2007 its intention to develop national standards to regulate this material as a non-hazardous waste, and has been developing or considering regulations governing the placement of ash in landfills, surface impoundments, sand/gravel surface mines and coal mines. In 2009, following the Tennessee Valley Authority ash release, the EPA announced it is considering regulating ash as a hazardous waste. Depending on its final scope, additional federal regulation has the potential to result in additional compliance requirements and costs that could be material. In addition, the Maryland Department of the Environment finalized regulations governing the disposal, storage, use and placement of ash in December 2008.

As a result of these regulatory proposals and our current ash generation projections, we are exploring our options for the management of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be approximately $60 million. Our estimates are subject to significant uncertainties, including the timing of any regulatory change, its implementation timetable, and the scope of the final requirements. As a result, we cannot predict our capital spending or the scope and timing of this project with certainty, and the actual expenditures, scope and timing could differ significantly from our estimates.

Employees

Constellation Energy and its consolidated subsidiaries (excluding CENG, which was deconsolidated on November 6, 2009) had approximately 7,200 employees at December 31, 2009.

Available Information

Constellation Energy maintains a website at constellation.com where copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments may be obtained free of charge. These reports are posted on our website the same day they are filed with the SEC. The SEC maintains a website (sec.gov), where copies of our filings may be obtained free of charge. The website address for BGE is bge.com. These website addresses are inactive textual references, and the contents of these websites are not part of this Form 10-K.

In addition, the website for Constellation Energy includes copies of our Corporate Governance Guidelines, Principles of Business Integrity, Corporate Compliance Program, Insider Trading Policy, Policy and Procedures with respect to Related Person Transactions, Information Disclosure Policy, and the charters of the Audit, Compensation and Nominating and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from our website or may be obtained from Constellation Energy upon written request to the Corporate Secretary.

The Principles of Business Integrity is a code of ethics that applies to all of our directors, officers, and employees, including the chief executive officer, chief financial officer, and chief accounting officer. We will post any amendments to, or waivers from, the Principles of Business Integrity applicable to our chief executive officer, chief financial officer, or chief accounting officer on our website.

Item 1A. Risk Factors

You should consider carefully the following risks, along with the other information contained in this Form 10-K. The risks and uncertainties described below are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 7. Management's Discussion and Analysis. If any of the following events actually occur, our business and financial results could be materially adversely affected.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by local, national, and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity may continue to result in a decline in energy consumption, an increase in customers' inability to pay their accounts, and lower commodity prices. These impacts may adversely affect our financial results and future growth.

Instability in the financial markets, as a result of recession or otherwise, may affect the cost of capital and our ability to raise capital. We rely on the capital and banking markets, as well as the periodic use of commercial paper to the extent available, to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit issued under our credit facilities to support our operations. Disruptions in the capital and credit markets as a result of uncertainty, reduced alternatives, or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses, including our ability to secure credit facilities and refinance debt that comes due, and our ability to complete other alternatives we are exploring. In addition, such disruptions could adversely affect our ability to draw on our credit facilities. Our access to funds under those credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from borrowers within a short period of time. The disruptions in capital and credit markets may also result in higher interest rates on publicly issued debt securities and increased costs associated with commercial paper borrowing and under bank credit facilities.

Any disruptions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, further changing our strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash. The inability to obtain the liquidity needed to meet our business requirements, or to obtain such liquidity on terms that are favorable to us, would have a material adverse effect on our business, results of operations and financial condition. If entities with which we do business are unable to raise capital or access the credit markets, they may be unable to perform their obligations or make payments under agreements we have with them. Defaults by these entities may have an adverse effect on our financial results.

Our generation investment plans may not achieve the desired financial results.

We may expand our generation capacity over the next several years through increasing the generating power of existing plants, the renovation of retired plants owned by us, and the construction or acquisition of new plants. The renovation, development, construction, and acquisition of additional generation capacity involve numerous risks. Any planned power uprates, construction, or renovation could result in cost overruns, lower than expected plant efficiency, and higher operating and other costs. We intend to use a portion of the proceeds received from the sale of an interest in our nuclear business to acquire new plants in regions where we have significant customer supply operations. Acquired plants may not generate the projected rates of return or sufficiently match generation capacity with customer supply volumes causing an increase in collateral requirements. With respect to the renovation of retired plants or the construction of new plants, we may incur significant sums for preliminary engineering, permitting, legal, and other expenses before it can be established whether a project is feasible, economically attractive, or capable of being financed.

If we were unable to complete the construction or renovation of a plant, we may not be able to recover our investment in the project. We may also be unable to run any new, acquired or renovated plants as efficiently as projected, which could result in higher-than-projected operating and other costs that adversely affect our financial results. Furthermore, increased energy conservation and use of renewable energy may reduce the value of our nonrenewable generation plants, as well as accelerate the obsolescence of older plants. If we cannot execute our generation investment plans successfully, our business, results of operations and financial condition could be adversely affected.

Changes in the prices of commodities, initial margin requirements, collateral posting asymmetries and types of collateral impact our liquidity requirements.

Our business is exposed to market fluctuations in the price and transportation costs of electricity, natural gas, coal, and other commodities. We seek to mitigate the effect of these fluctuations through various hedging strategies, which may require the posting of collateral by both us and our counterparties. Changes in the prices of commodities and initial margin requirements for exchange-traded contracts can affect the amount of collateral that must be posted, depending on the particular position we hold.

There are certain asymmetries relating to the use of collateral that create liquidity requirements for our merchant energy business. These asymmetries arise as a result of our actions to be economically hedged as well as market conditions or conventions for conducting business that result in some transactions being collateralized while others are not, including:

- In our Customer Supply operation, we generally do not receive collateral under contractual obligations to supply our customers, but our Global Commodities operation may hedge these transactions through purchases that generally require us to post collateral.
- In our Generation operation, we may have to post collateral on our power sale or fuel purchase contracts.

As a result, significant changes in the prices of commodities and margin requirements for exchange-traded contracts could require us to post additional collateral from time to time without our counterparties having to post cash collateral to us, which could adversely affect our overall liquidity and ability to finance our operations, which, in turn, could adversely affect our credit ratings. Additionally, posting letters of credit to counterparties to meet collateral requirements adversely impacts our liquidity, while the receipt of letters of credit as collateral does not improve our liquidity.

Our merchant energy business may incur substantial costs and liabilities and be exposed to price volatility and counterparty performance risk as a result of its participation in the wholesale energy markets.

We purchase and sell power and fuel in markets exposed to significant risks, including price volatility for electricity and fuel and the credit risks of counterparties with which we enter into contracts.

We use various hedging strategies in an effort to mitigate many of these risks. However, hedging transactions do not guard against all risks and are not always effective, as they are based upon predictions about future market conditions. The inability or failure to effectively hedge assets or fuel or power positions against changes in commodity prices, interest rates, counterparty credit risk or other risk measures could significantly impair our future financial results.

Exposure to electricity price volatility. We buy and sell electricity in both the wholesale bilateral markets and spot markets, which expose us to the risks of rising and falling prices in those markets, and our cash flows may vary accordingly. At any given time, the wholesale spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. This is highly dependent on the regional generation market. In many cases, the next unit of electricity supplied would be supplied from generating stations fueled by fossil fuels, primarily coal, natural gas and oil. Consequently, the open market wholesale price of electricity may reflect the cost of coal, natural gas or oil plus the cost to convert the fuel to electricity and an appropriate return on capital. Therefore, changes in the supply and cost of coal, natural gas and oil may impact the open market wholesale price of electricity.

A portion of our power generation facilities operates wholly or partially without long-term power purchase agreements. As a result, power from these facilities is sold on the spot market or on a short-term contractual basis, which if not fully hedged may affect the volatility of our financial results.

Exposure to fuel cost volatility. Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs. In addition, new sources of natural gas supplies from domestic shale production, as well as rising liquid natural gas (LNG) exports, could increase the long-term supply of natural gas and create a fundamental and long-lasting decline in natural gas prices. Lower natural gas prices could contribute to a decline in power generation prices that could have an adverse effect on our financial results and cash flows. As a result, fuel price changes may adversely affect our financial results.

Exposure to counterparty performance. Our merchant energy business enters into transactions with numerous third parties (commonly referred to as "counterparties"). In these arrangements, we are exposed to the credit risks of our counterparties and the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power. In addition, we enter into various wholesale transactions through Independent System Operators (ISOs). These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These risks are exacerbated during periods of commodity price fluctuations. If a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of derivative contracts recorded at fair value, the amount owed for settled transactions, and additional payments, if any, that we would have to make to settle unrealized losses on accrual contracts. Defaults by suppliers and other counterparties may adversely affect our financial results.

Reduced liquidity in the markets in which we operate could impair our ability to appropriately manage the risks of our operations.

We are an active participant in energy markets through our competitive energy businesses. The liquidity of regional energy markets is an important factor in our ability to manage risks in these operations. Over the past several years, market participants in the merchant energy business have ended or significantly reduced their activities as a result of several factors, including government investigations, changes in market design, and deteriorating credit quality. As a result, several regional energy markets experienced a significant decline in liquidity, which, in turn, has impacted our ability to enter into certain types of transactions to manage our risks for settlement periods beyond 18 to 24 months. Liquidity in the energy markets can be adversely affected by various factors, including price volatility and the availability of credit. As a result, future reductions in liquidity may restrict our ability to manage our risks and this could impact our financial results.

We often rely on single suppliers and at times on single customers, exposing us to significant financial risks if either should fail to perform their obligations.

We often rely on a single supplier for the provision of fuel, water, and other services required for operation of a facility, and at times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that provide the support for any project debt used to finance the facility. The failure of any one customer or supplier to fulfill its contractual obligations could negatively impact our financial results.

We may not fully hedge our generation assets, customer supply activities, or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.

To lower our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments, weather positions, fuel requirements, inventories of natural gas, coal and other commodities, and competitive supply obligations. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, we may not cover the entire exposure of our assets or positions to market price volatility, and the coverage will vary over time. Fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged positions.

In addition, risk management tools and metrics such as economic value at risk, daily value at risk, and stress testing are based on historical price movements. If price movements significantly or persistently deviate from historical behavior, risk limits may not fully protect us from significant losses.

Our risk management policies and procedures may not always work as planned. As a result of these and other factors, we cannot predict with precision the impact that risk management decisions may have on our financial results.

The use of derivative and nonderivative contracts in the normal course of business could result in financial losses that negatively impact our financial results.

We use derivative instruments such as swaps, options, futures and forwards, as well as nonderivative contracts, to manage our commodity and financial market risks and to engage in trading activities. We could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

In the absence of actively quoted market prices and pricing information from external sources, the valuation of derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Additionally, the settlement of derivative instruments could reflect a realized value that differs from our reported estimates of fair value.

Inaccurate assumptions and estimates in the models we use could adversely impact our financial results.

We deploy many models to value merchant contracts, derivatives and assets, to dispatch power from our generation plants, and to measure the risks and costs of various transactions and businesses. Also, a significant portion of our business relies on the assumptions underlying the forecasting of customer load, correlations between prices of energy commodities and weather and the creditworthiness of our customers and other third parties. Inaccurate estimates of various business assumptions used in those models could create the mispricing of customer contracts and assets or the incorrect measurement of key risks relating to our portfolios and businesses that could adversely impact our financial results.

Poor market performance will affect our pension plan investments, which may adversely affect our liquidity and financial results.

At December 31, 2009, our qualified pension obligations were approximately $327 million greater than the fair value of our plan assets. The Pension Protection Act requires that we fully fund our obligations by 2015. The performance of the capital markets will affect the value of the assets that are held in trust to satisfy our future obligations under our qualified pension plans. A decline in the market value of those assets or the failure of those assets to earn an adequate return may increase our funding requirements for these obligations, which may adversely affect our liquidity and financial results.

The operation of power generation facilities involves significant risks that could adversely affect our financial results.

We own, operate and have ownership interests in a number of power generation facilities. The operation of power generation facilities involves many risks, including start-up risks, breakdown or failure of equipment, transmission lines, substations or pipelines, use of new technology, the dependence on a specific fuel source, including the transportation of fuel, or the impact of unusual or adverse weather conditions (including natural disasters such as hurricanes) or environmental compliance, as well as the risk of performance below expected or contracted levels of output or efficiency. This could result in lost revenues and/or increased expenses. Insurance, warranties, or performance guarantees may not cover any or all of the lost revenues or increased expenses, including the cost of replacement power. A portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures to keep it operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvement. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of the agreement or incurring a liability for liquidated damages.

Our generation business may incur substantial costs and liabilities due to our ownership interest in nuclear generating facilities.

We own substantial interests in nuclear power plants. Operation of these plants exposes us to risks in addition to those that result from owning and operating non-nuclear power generation facilities. These risks include normal operating risks for a nuclear facility and the risks of a nuclear accident.

Nuclear Operating Risks. The operation of nuclear generating facilities involves routine operating risks, including:

- mechanical or structural problems;
- inadequacy or lapses in maintenance protocols;
- impairment of reactor operation and safety systems due to human or mechanical error;
- costs of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel;
- regulatory actions, including shut down of units because of public safety concerns, whether at our plants or other nuclear operators;
- limitations on the amounts and types of insurance coverage commercially available;
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities; and
- environmental risks, including risks associated with changes in environmental legal requirements.

Nuclear Accident Risks. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed the insurance coverage available from both private sources and an industry retrospective payment plan. In addition, in the event of an accident at one of our nuclear joint ventures or another participating insured party's nuclear plants, CENG could be assessed retrospective insurance premiums (because all nuclear plant operators contribute to a nationwide catastrophic insurance fund). Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on our financial results.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations and may expose us to environmental liabilities.

We are subject to extensive federal, state, and local environmental statutes, rules, and regulations relating to air quality, water quality, waste management, wildlife protection, the management of natural resources, and the protection of human health and safety that could, among other things, require additional pollution control equipment, limit the use of certain fuels, restrict the output of certain facilities, or otherwise increase costs. Significant capital expenditures, operating and other costs are associated with compliance with environmental requirements, and these expenditures and costs could become even more significant in the future as a result of regulatory changes.

Examples of potential future regulatory changes include additional regulation of greenhouse gas emissions at the federal, regional, and/or state level, heightened enforcement of new source review requirements, increased regulation of coal combustion by-products, and mandated investment in renewable energy resources. One or more of these changes could increase our compliance and operating costs or require significant commitments of capital.

We are subject to liability under environmental laws for the costs of remediating environmental contamination. Remediation activities include the cleanup of current facilities and former properties, including manufactured gas plant operations and offsite waste disposal facilities. The remediation costs could be significantly higher than the liabilities recorded by us. Also, our subsidiaries are currently involved in proceedings relating to sites where hazardous substances have been released and may be subject to additional proceedings in the future.

We are subject to legal proceedings by individuals alleging injury from exposure to hazardous substances and could incur liabilities that may be material to our financial results. Additional proceedings could be filed against us in the future.

We may also be required to assume environmental liabilities in connection with future acquisitions. As a result, we may be liable for significant environmental remediation costs and other liabilities arising from the operation of acquired facilities, which may adversely affect our financial results.

We, and BGE in particular, are subject to extensive local, state and federal regulation that could affect our operations and costs.

We are subject to regulation by federal and state governmental entities, including the FERC, the NRC, the Maryland PSC and the utility commissions of other states in which we have operations. In addition, changing governmental policies and regulatory actions can have a significant impact on us. Regulations can affect, for example, allowed rates of return, requirements for plant operations, recovery of costs, limitations on dividend payments, and the regulation or re-regulation of wholesale and retail competition.

BGE's distribution rates are subject to regulation by the Maryland PSC, and such rates are effective until new rates are approved. If the Maryland PSC does not approve adequate new rates, BGE might not be able to recover certain costs it incurs or earn an adequate rate of return. In addition, limited categories of costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover material costs not included in rates or adjustment clauses, including increases in uncollectible customer accounts that may result from higher gas and electric costs or as a result of Maryland PSC policies or rulings, could have an adverse effect on our, or BGE's, cash flow and financial position.

Energy legislation enacted in Maryland in June 2006 and April 2007 mandated that the Maryland PSC review Maryland's deregulated electricity market. Although the settlement agreement reached with the State of Maryland in March 2008 terminated certain studies relating to the 1999 deregulation settlement, the State of Maryland is still undertaking a review of the Maryland electric industry and market structure to consider various options for providing standard offer service to residential customers, including re-regulation. We cannot at this time predict the final outcome of this review or how such outcome may affect our, or BGE's financial results, but it could be material.

We are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation (NERC) and enforced by the FERC. Compliance with the mandatory reliability standards may subject us to higher operating costs and may result in increased capital expenditures. If we are found to be in noncompliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Further, federal and/or state regulatory approval may be necessary for us to complete transactions. As part of the regulatory approval process, governmental entities may impose terms and conditions on the transaction or our business that are unfavorable or add significant additional costs to our future operations.

The regulatory and legislative process may restrict our ability to grow earnings in certain parts of our business, cause delays in or affect business planning and transactions and increase our, or BGE's, costs.

We operate in deregulated segments of the electric and gas industries created by federal and state restructuring initiatives. If competitive restructuring of the electric or gas industries is reversed, discontinued, restricted, or delayed, our business prospects and financial results could be materially adversely affected.

The regulatory environment applicable to the electric and natural gas industries has undergone substantial changes as a result of restructuring initiatives at both the state and federal levels. These initiatives have had a significant impact on the nature of the electric and natural gas industries and the manner in which their participants conduct their businesses. We have targeted the competitive segments of the electric and natural gas industries created by these initiatives.

Due to recent events in the energy markets, energy companies have been under increased scrutiny by state legislatures, regulatory bodies, capital markets, and credit rating agencies. This increased scrutiny could lead to substantial changes in laws and regulations affecting us, including modifications to the auction processes in competitive markets and new accounting standards that could change the way we are required to record revenues, expenses, assets, and liabilities. Recent proposals in the State of Maryland, relating to the structure of the electric industry in Maryland and various options for re-regulation of the industry are examples of how these laws and regulations can change.

Further, additional regulation of the derivatives markets has been proposed recently in the United States Congress and by the Commodity Futures Trading Commission, which could require us to post additional cash collateral and have a material adverse effect on our business. We cannot predict the future development of regulation or legislation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

If competitive restructuring of the electric and natural gas markets is reversed, discontinued, restricted, or delayed, or if the recent Maryland PSC or legislative proposals are implemented in a manner adverse to us, our business prospects and financial results could be negatively impacted.

Our financial results may be harmed if transportation and transmission availability is limited or unreliable.

We have business operations throughout the United States and internationally. As a result, we depend on transportation and transmission facilities owned and operated by utilities and other energy companies to deliver the electricity, coal, and natural gas we sell to the wholesale and retail markets, as well as the natural gas and coal we purchase to supply some of our generating facilities. If transportation or transmission is disrupted or capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our ability to provide electricity, coal, or natural gas to our customers or power plants and may materially adversely affect our financial results.

BGE's electric and gas infrastructure is subject to operational failure and may require significant expenditures to maintain.

Much of BGE's electric and gas operational systems and infrastructure, such as gas mains and pipelines and electric transmission and distribution equipment, has been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including due to events that are beyond BGE's control, and may require significant expenditures to operate efficiently, which could have an adverse effect on our, or BGE's, financial results.

Our merchant energy business has contractual obligations to certain customers to provide full requirements service, which makes it difficult to predict and plan for load requirements and may result in reduced revenues and increased operating costs to our business.

Our merchant energy business has contractual obligations to certain customers to supply full requirements service to such customers to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of load that our merchant energy business must be prepared to supply to customers may increase our operating costs. The process of estimating the load requirements of our customers has been further complicated by the decreased demand resulting from economic and financial instability since 2008. A significant under- or over-estimation of load requirements could result in our merchant energy business not having enough power or having too much power to cover its load obligation, in which case it would be required to buy or sell power from or to third parties at prevailing market prices. Those prices may not be favorable and thus could reduce our revenues and/or increase our operating costs and result in the possibility of reduced earnings or incurring losses.

Our financial results may fluctuate on a seasonal and quarterly basis or as a result of severe weather.

Our business is affected by weather conditions. Our overall operating results may fluctuate substantially on a seasonal basis, and the pattern of this fluctuation may change depending on the nature and location of any facility we acquire and the terms of any contract to which we become a party. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities.

Generally, demand for electricity peaks in winter and summer and demand for gas peaks in the winter. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less electric and gas consumption than forecasted. Depending on prevailing market prices for electricity and gas, these and other unexpected conditions may reduce our revenues and results of operations. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Severe weather can be destructive, causing outages and/or property damage. This could require us to incur additional costs. Catastrophic weather, such as hurricanes, could impact our or our customers' operating facilities, communication systems and technology. Unfavorable weather conditions may have a material adverse effect on our financial results.

A failure in our operational systems or infrastructure, or those of third parties, may adversely affect our financial results.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, accounting, or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

We may also be subject to disruptions of our operational systems arising from events that are wholly or partially beyond our control (for example, natural disasters, acts of terrorism, epidemics, computer viruses and telecommunications outages). Third party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt one or more of our businesses, result in potential liability or reputational damage or otherwise have an adverse affect on our financial results.

Our ability to successfully identify, complete and integrate acquisitions is subject to significant risks, including the effect of increased competition.

We are likely to encounter significant competition for acquisition opportunities that may become available. In addition, we may be unable to identify attractive acquisition opportunities at favorable prices, to secure the financing necessary to undertake them, or to successfully and timely complete and integrate them.

War and threats of terrorism and catastrophic events that could result from terrorism may impact our results of operations in unpredictable ways.

We cannot predict the impact that any future terrorist attacks may have on the energy industry in general and on our business in particular. In addition, any retaliatory military strikes or sustained military campaign may affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. The possibility alone that infrastructure facilities, such as electric generation, electric and gas transmission and distribution facilities would be direct targets of, or indirect casualties of, an act of terror may affect our operations. Furthermore, terrorist attacks could compromise the physical or cyber security of our facilities, which could adversely affect our ability to manage these facilities effectively.

Such activity may have an adverse effect on the United States economy in general. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our financial results or restrict our future growth. Instability in the financial markets as a result of terrorism or war may affect our stock price and our ability to raise capital.

A downgrade in our credit ratings could negatively affect our ability to access capital and/or operate our wholesale and retail competitive supply businesses.

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. If any of our credit ratings were to be downgraded, especially below investment grade, our ability to raise capital on favorable terms, including in the commercial paper markets, if available, could be hindered, and our borrowing costs would increase. Additionally, the business prospects of our wholesale and retail competitive supply businesses, which in many cases rely on the creditworthiness of Constellation Energy, would be negatively impacted. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade. Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that exceeds our available liquidity. Some of the factors that affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, and political, legislative, and regulatory events.

We are subject to employee workforce factors that could affect our businesses and financial results.

We are subject to employee workforce factors, including loss or retirement of key executives or other employees, availability of qualified personnel, collective bargaining agreements with union employees, and work stoppage that could affect our financial results. In particular, our competitive energy businesses are dependent, in part, on recruiting and retaining personnel with experience in sophisticated energy transactions and the functioning of complex wholesale markets.

The sale of non-nuclear generation plants pursuant to the put arrangement with EDF may have an adverse effect on our financial results.

We have entered into a put arrangement with EDF that provides us with additional liquidity of up to $2.0 billion by allowing us to exercise an option to require EDF to acquire certain specified non-nuclear generation plants at pre-agreed prices. To the extent we exercise this option, we will no longer own the plants sold to EDF and will not be able to recognize their financial results, which may have an adverse effect on our future financial results. In addition, exercise of the option may adversely impact our relationship with EDF, which could have an adverse impact on our CENG and UNE nuclear joint ventures with EDF. This put arrangement expires on December 31, 2010.

Our ability to develop new nuclear generation could have an effect on our business and financial results.

We are in the forefront of the proposed development of new nuclear generation in the United States through our UNE joint venture. Nuclear generation development projects are large and complex and there have been no new orders for a nuclear plant in the United States since the 1970s. The costs incurred to construct a new nuclear plant would be significant and adequate returns on investment may not be realized for many years, if at all. Feasibility and successful construction of nuclear plants depend on a variety of factors, including receipt of required permits, terms of financing, impact of competing generation and nuclear technologies, materials, labor and nuclear waste disposal costs and regulation of nuclear facilities. These factors could generate higher construction and financial costs, delays, environmental and other liabilities, or an adverse impact to our credit rating. These factors may also lead to a decision not to proceed with the construction of new nuclear facilities, which could have an adverse effect on our business and financial results, including a potential impairment of our investment in UNE.

Item 2. Properties

Constellation Energy occupies approximately 1,130,000 square feet of leased and owned office space in North America, which includes its corporate offices in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

BGE owns its principal headquarters building located in downtown Baltimore. BGE also leases approximately 4,700 square feet of office space. In addition, BGE owns propane air and liquefied natural gas facilities as discussed in *Item 1. Business—Gas Business* section.

BGE also has rights-of-way to maintain 26-inch natural gas mains across certain Baltimore City-owned property (principally parks) which expired in 2004. BGE is in the process of renewing the rights-of-way with Baltimore City for an additional 25 years. The expiration of the rights-of-way does not affect BGE's ability to use the rights-of-way during the renewal process.

BGE has electric transmission and electric and gas distribution lines located:

- in public streets and highways pursuant to franchises, and
- on rights-of-way secured for the most part by grants from owners of the property.

We believe we have satisfactory title to our power project facilities in accordance with standards generally accepted in the energy industry, subject to exceptions, which in our opinion, would not have a material adverse effect on the use or value of the facilities.

Our merchant energy business owns several natural gas producing properties.

The following table describes our generating facilities:

Plant	Location	At December 31, 2009 Capacity (MW)	% Owned	Capacity Owned (MW)	2009 Capacity Factor (%)	Primary Fuel
Calvert Cliffs Unit 1 (1)	Calvert Co., MD	855	50.0	428	98.4	Nuclear
Calvert Cliffs Unit 2 (1)	Calvert Co., MD	850	50.0	425	92.9	Nuclear
Nine Mile Point Unit 1 (1)	Scriba, NY	620	50.0	310	91.9	Nuclear
Nine Mile Point Unit 2 (1)	Scriba, NY	1,138	41.0	467	99.5	Nuclear
R.E. Ginna (1)	Ontario, NY	581	50.0	291	90.7	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,273	100.0	1,273	59.3	Coal
H. A. Wagner	Anne Arundel Co., MD	976	100.0	976	26.8	Coal/Oil/Gas
C. P. Crane (2)	Baltimore Co., MD	399	100.0	399	30.4	Oil/Coal
Keystone (2)	Armstrong and Indiana Cos., PA	1,711	21.0	359(4)	70.3	Coal
Conemaugh (2)	Indiana Co., PA	1,711	10.6	181(4)	81.1	Coal
Perryman (2)	Harford Co., MD	347	100.0	347	1.6	Oil/Gas
Riverside	Baltimore Co., MD	228	100.0	228	0.1	Oil/Gas
Handsome Lake (2)	Rockland Twp, PA	268	100.0	268	1.5	Gas
Notch Cliff	Baltimore Co., MD	101	100.0	101	0.3	Gas
Westport	Baltimore City, MD	116	100.0	116	—	Gas
Gould Street	Baltimore City, MD	97	100.0	97	0.8	Gas
Philadelphia Road	Baltimore City, MD	61	100.0	61	0.1	Oil
Safe Harbor (2)	Safe Harbor, PA	417	66.7	278	29.3	Hydro
Grande Prairie (2)	Alberta, Canada	85	100.0	85	8.3	Gas
West Valley (2)	Salt Lake City, UT	200	100.0	200	14.1	Gas
Panther Creek (2)	Nesquehoning, PA	80	50.0	40	96.5	Waste Coal
Colver (2)	Colver Township, PA	102	25.0	26	100.0	Waste Coal
Sunnyside (2)	Sunnyside, UT	51	50.0	26	92.1	Waste Coal
ACE (2)	Trona, CA	102	31.1	32	88.0	Coal
Jasmin	Kern Co., CA	35	50.0	18	95.6	Coal
POSO	Kern Co., CA	35	50.0	18	94.0	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	4	61.8	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	10	50.0	5	100.0	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	10	50.0	5	100.0	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	84.8	Biomass
Fresno	Fresno, CA	24	50.0	12	86.3	Biomass
Chinese Station	Jamestown, CA	20	45.0	9	72.9	Biomass
Malacha	Muck Valley, CA	32	50.0	16	11.4	Hydro
SEGS IV	Kramer Junction, CA	33	12.2	4	29.3	Solar
SEGS V	Kramer Junction, CA	24	4.2	1	37.8	Solar
SEGS VI	Kramer Junction, CA	34	8.8	3	29.2	Solar
Total Generating Facilities (3)		12,658		7,118		

(1) We own a 50.01% membership interest in CENG, the joint venture with EDF that holds these nuclear generating assets as a result of the sale of a 49.99% interest in CENG to EDF that was completed in November 2009. We discuss this transaction in more detail in Note 2 to Consolidated Financial Statements.

(2) In connection with an Investment Agreement with EDF, we have the option to sell one or more of these facilities to EDF for aggregate proceeds of up to $2 billion through December 31, 2010.

(3) The sum of the individual plant capacity megawatts may not equal the total due to the effects of rounding.

(4) Reflects our proportionate interest in and entitlement to capacity from Keystone and Conemaugh, which include 2 MW of diesel capacity for Keystone and 1 MW of diesel capacity for Conemaugh.

In 2009, we signed an agreement to acquire the 70 MW Criterion wind project in Garrett County, Maryland. Upon closing, we plan to complete the construction of the project and expect it to be ready for commercial operation in late 2010.

In December 2009, we were selected by the State of Maryland to develop an approximately 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. This $60 million solar facility will be constructed, owned, operated and maintained by us. We expect the project to be completed by December 2012.

In February 2008, we acquired the Hillabee Energy Center, a partially completed 740 MW gas-fired combined cycle power generation facility located in Alabama. We plan to complete the construction of this facility and expect it to be ready for commercial operation in the first quarter of 2010.

As of December 31, 2009, we also have a 50% ownership interest in a waste coal processing facility located in Hazelton, Pennsylvania.

Item 3. Legal Proceedings

We discuss our legal proceedings in Note 12 to Consolidated Financial Statements.

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	55	Chairman of the Board (since July 2002), President and Chief Executive Officer (since November 2001) of Constellation Energy	Chairman of the Board of Baltimore Gas and Electric Company
Michael J. Wallace	62	Vice Chairman (since March 2008), Executive Vice President (since January 2004) and Chief Operating Officer (since May 2009) of Constellation Energy	President and Chief Executive Officer—Constellation Energy Nuclear Group, LLC
Henry B. Barron	59	Executive Vice President of Constellation Energy (since April 2008); and President, Chief Executive Officer and Chief Nuclear Officer (since September 2008) of Constellation Energy Nuclear Group	Group Executive and Chief Nuclear Officer—Duke Energy
James L. Connaughton	48	Executive Vice President, Corporate Affairs, Public and Environmental Policy (since February 2009)	Chairman of the White House Council on Environmental Quality and Director of the White House Office of Environmental Policy
Paul J. Allen	58	Senior Vice President (since January 2004) and Chief Environmental Officer (since June 2007) of Constellation Energy	None
Charles A. Berardesco	51	Senior Vice President (since October 2008), General Counsel (since October 2008) and Corporate Secretary (since July 2004) of Constellation Energy	Vice President and Deputy General Counsel—Constellation Energy; and Associate General Counsel—Constellation Energy
Brenda L. Boultwood	45	Senior Vice President and Chief Risk Officer of Constellation Energy (since January 2008)	Global Head of Strategy and Global Head of Derivative Services, Alternative Investment Services and Head of Treasury Services Risk Management—J.P. Morgan Chase & Company
Kenneth W. DeFontes, Jr.	59	Senior Vice President of Constellation Energy (since October 2004); and President and Chief Executive Officer of Baltimore Gas and Electric Company (since October 2004)	None
Andrew L. Good	42	Senior Vice President, Corporate Strategy and Development of Constellation Energy (since November 2009)	Senior Vice President and Chief Financial Officer—Constellation Energy Resources; Senior Vice President and Chief Financial Officer—Constellation Energy Commodities Group; and Senior Vice President, Finance—Constellation Energy
Kathleen W. Hyle	51	Senior Vice President of Constellation Energy (since September 2005); and Chief Operating Officer of Constellation Energy Resources (since November 2008)	Senior Vice President, Finance, and Chief Financial Officer—Constellation Energy Nuclear Group; Chief Financial Officer—UniStar Nuclear Energy; Senior Vice President, Finance—Constellation Energy; and Chief Financial Officer, Constellation NewEnergy
Shon J. Manasco	39	Senior Vice President and Chief Human Resources Officer of Constellation Energy (since August 2009)	Vice President, Human Resources—Constellation Energy Resources; Senior Vice President, Global Head of Human Resources—Banc of America Securities
Jonathan W. Thayer	38	Senior Vice President and Chief Financial Officer of Constellation Energy (since October 2008)	Vice President and Managing Director, Corporate Strategy and Development—Constellation Energy; Treasurer—Constellation Energy; and Senior Vice President and Chief Financial Officer—Baltimore Gas and Electric Company

Officers are elected by, and hold office at the will of, the Board of Directors and do not serve a "term of office" as such. There is no arrangement or understanding between any officer and any other person pursuant to which the officer was selected.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters, Issuer Purchases of Equity Securities, and Unregistered Sales of Equity and Use of Proceeds

Stock Trading

Constellation Energy's common stock is traded under the ticker symbol CEG. It is listed on the New York and Chicago stock exchanges.

As of January 29, 2010, there were 35,016 common shareholders of record.

Dividend Policy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends, except certain of our credit facilities prohibit us from increasing our common stock dividend without the consent of the lenders.

Dividends have been paid continuously since 1910 on the common stock of Constellation Energy, BGE, and their predecessors. Future dividends depend upon future earnings, our financial condition, and other factors.

In January 2010, we announced a quarterly dividend of $0.24 per share payable April 1, 2010 to holders of record at the close of business on March 10, 2010. This is equivalent to an annual rate of $0.96 per share.

Quarterly dividends were declared on our common stock during 2009 and 2008 in the amounts set forth below.

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated under the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. There are no other limitations on BGE paying common stock dividends unless:

- BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or
- any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Common Stock Dividends and Price Ranges

	2009			2008		
	Dividend Declared	Price High	Price Low	Dividend Declared	Price High	Price Low
First Quarter	$0.24	$27.97	$15.05	$0.4775	$107.97	$81.94
Second Quarter	0.24	28.05	20.18	0.4775	94.62	78.74
Third Quarter	0.24	33.37	25.76	0.4775	85.53	13.00
Fourth Quarter	0.24	36.55	30.24	0.4775	30.17	21.70
Total	$0.96			$ 1.91		

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased (1)	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Amount of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
October 1 - October 31, 2009	114	$32.70	—	—
November 1 - November 30, 2009	5,954	32.45	—	—
December 1 - December 31, 2009	—	—	—	—
Total	6,068	$32.45	—	—

(1) *Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock and restricted stock units.*

Item 6. Selected Financial Data
Constellation Energy Group, Inc. and Subsidiaries

	2009	2008	2007	2006	2005
		(In millions, except per share amounts)			
Summary of Operations					
Total Revenues	**$15,598.8**	$19,741.9	$21,185.1	$19,271.1	$16,964.7
Total Expenses	**14,588.5**	20,821.9	19,858.8	18,025.2	16,023.8
Equity (losses) earnings	**(6.1)**	76.4	8.1	13.8	3.6
Gain on Sale of Interest in CENG	**7,445.6**	—	—	—	—
Net (Loss) Gain on Divestitures	**(468.8)**	25.5	—	73.8	—
Income (Loss) From Operations	**7,981.0**	(978.1)	1,334.4	1,333.5	944.5
Gains on Sales of CEP LLC equity	**—**	—	63.3	28.7	—
Other (Expense) Income	**(140.7)**	(69.5)	157.4	66.8	64.5
Fixed Charges	**350.1**	349.1	292.4	315.5	297.0
Income (Loss) Before Income Taxes	**7,490.2**	(1,396.7)	1,262.7	1,113.5	712.0
Income Tax Expense (Benefit)	**2,986.8**	(78.3)	428.3	351.0	163.9
Income (Loss) from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**4,503.4**	(1,318.4)	834.4	762.5	548.1
(Loss) Income from Discontinued Operations, Net of Income Taxes	**—**	—	(0.9)	187.8	94.4
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes	**—**	—	—	—	(7.2)
Net Income (Loss)	**$ 4,503.4**	$ (1,318.4)	$ 833.5	$ 950.3	$ 635.3
Net (Income) Loss Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**60.0**	(4.0)	12.0	13.9	12.2
Net Income (Loss) Attributable to Common Stock	**$ 4,443.4**	$ (1,314.4)	$ 821.5	$ 936.4	$ 623.1
Earnings (Loss) Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ 22.19**	$ (7.34)	$ 4.51	$ 4.12	$ 2.98
(Loss) Income from Discontinued Operations	**—**	—	(0.01)	1.04	0.53
Cumulative Effects of Changes in Accounting Principles	**—**	—	—	—	(0.04)
Earnings (Loss) Per Common Share Assuming Dilution	**$ 22.19**	$ (7.34)	$ 4.50	$ 5.16	$ 3.47
Dividends Declared Per Common Share	**$ 0.96**	$ 1.91	$ 1.74	$ 1.51	$ 1.34

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Summary of Financial Condition					
Total Assets	**$23,544.4**	$22,284.1	$21,742.3	$21,801.6	$21,473.9
Current Portion of Long-Term Debt	**$ 56.9**	$ 2,591.5	$ 380.6	$ 878.8	$ 491.3
Capitalization:					
Long-Term Debt	**$ 4,814.0**	$ 5,098.7	$ 4,660.5	$ 4,222.3	$ 4,369.3
Noncontrolling Interests	**75.3**	20.1	19.2	94.5	22.4
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**8,697.1**	3,181.4	5,340.2	4,609.3	4,915.5
Total Capitalization	**$13,776.4**	$ 8,490.2	$10,209.9	$ 9,116.1	$ 9,497.2
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**14.76**	N/A	3.84	4.05	3.04
Book Value Per Share of Common Stock	**$ 43.27**	$ 15.98	$ 29.93	$ 25.54	$ 27.57

N/A—Calculation is not applicable as a result of the net loss for 2008.

We discuss items that affect comparability between years, including acquisitions and dispositions, accounting changes and other items, in *Item 7. Management's Discussion and Analysis.*

	2009	2008	2007	2006	2005
			(In millions)		
Summary of Operations					
Total Revenues	**$3,579.0**	$3,703.7	$3,418.5	$3,015.4	$3,009.3
Total Expenses	**3,310.6**	3,521.2	3,084.2	2,646.3	2,612.8
Income From Operations	**268.4**	182.5	334.3	369.1	396.5
Other Income	**25.4**	29.6	26.9	6.0	5.9
Fixed Charges	**139.3**	139.9	125.3	102.6	93.5
Income Before Income Taxes	**154.5**	72.2	235.9	272.5	308.9
Income Taxes	**63.8**	20.7	96.0	102.2	119.9
Net Income	**90.7**	51.5	139.9	170.3	189.0
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**$ 77.5**	$ 38.3	$ 126.7	$ 157.1	$ 175.8
Net Loss (Income) Attributable to Noncontrolling Interests	**7.3**	—	(0.1)	—	—
Net Income Attributable to Common Stock	**$ 84.8**	$ 38.3	$ 126.6	$ 157.1	$ 175.8

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

	2009	2008	2007	2006	2005
Summary of Financial Condition					
Total Assets	**$6,453.1**	$6,086.2	$5,783.0	$5,140.7	$4,742.1
Current Portion of Long-Term Debt	**$ 56.5**	$ 90.0	$ 375.0	$ 258.3	$ 469.6
Capitalization					
Long-Term Debt	**$2,141.4**	$2,197.7	$1,862.5	$1,480.5	$1,015.1
Noncontrolling Interest	**17.6**	16.9	16.8	16.7	18.3
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,938.8**	1,538.2	1,671.7	1,651.5	1,622.5
Total Capitalization	**$4,287.8**	$3,942.8	$3,741.0	$3,338.7	$2,845.9
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.07**	1.50	2.84	3.60	4.22
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**1.80**	1.33	2.42	2.99	3.45

We discuss items that affect comparability between years, including accounting changes and other items, in *Item 7. Management's Discussion and Analysis*.

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries and joint ventures including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in *Note 3 to Consolidated Financial Statements*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business in more detail in *Item 1. Business* section and the risk factors affecting our business in *Item 1A. Risk Factors* section.

In this discussion and analysis, we will explain the general financial condition of and the results of operations for Constellation Energy and BGE including:

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,
- expected sources of cash for future capital expenditures,
- our net available liquidity and collateral requirements, and
- expected future expenditures for capital projects.

As you read this discussion and analysis, refer to our Consolidated Statements of Income (Loss), which present the results of our operations for 2009, 2008, and 2007. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income (Loss).

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- Then, we describe the business environment in which we operate including how recent events, regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results of operations and require management's most difficult, subjective or complex judgment.
- We highlight significant events that are important to understanding our results of operations and financial condition.
- We review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition addressing our sources and uses of cash, security ratings, capital resources, capital requirements, commitments, and off-balance sheet arrangements.
- We conclude with a discussion of our exposure to various market risks.

Strategy

As a result of significant market events in 2008, we previously disclosed plans to refocus and, in some cases, exit parts of our merchant energy business. We also sought to increase available liquidity and reduce our business risk. In addition, in November 2009, we completed a transaction to sell to EDF Group and affiliates (EDF) a 49.99% interest in our nuclear generation and operation business. This transaction brought us stability as a stand-alone company as well as improved our liquidity. We discuss the transaction with EDF and our divestitures in *Note 2 to Consolidated Financial Statements* and our available liquidity and risk management activities later in this *Item 7*.

We are pursuing a strategy of owning and operating generation facilities, providing energy and energy-related products and services through our Customer Supply activities, and delivering electricity and gas to customers of BGE, our regulated utility located in central Maryland. Our merchant energy business is focusing on short-term and long-term purchases and sales of energy, capacity, and related products to various customers, including distribution utilities, municipalities, cooperatives, and residential, industrial, commercial, and governmental customers.

We obtain this energy from both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets and includes various fuel types, such as coal, natural gas, oil, and renewable sources. In addition to owning generating facilities, we contract for power from other merchant providers, typically through power purchase agreements. We use both our owned generation and our contracted generation to support our wholesale and retail Customer Supply operations.

Our merchant energy business actively manages our Customer Supply operations with both physical and contractual assets in order to derive incremental value. The combination of our Generation and Customer Supply operations allows us to manage our Customer Supply operations in a collateral-efficient manner. Through our retail sales channels, we are able to manage our generation with lower requirements to post collateral. Additionally, when we use owned or contracted generation, we reduce our collateral posting requirements.

We have load obligations greater than our generation assets. Going forward, we intend to buy generation assets and enter into longer-tenor agreements with merchant generators in regions where we currently serve load but do not have a significant generation presence. We believe that by better matching generating assets with our load obligations, we will be able to further reduce our dependence on exchange-traded products, thereby lowering our collateral requirements. We believe that the proceeds received from the transaction with EDF, along with overall market conditions, provide the resources and potential opportunities to add to our generation assets at attractive prices over the next two to three years.

At BGE, we are also focused on enhancing reliability, customer satisfaction, and customer demand response initiatives.

Customer choice, regulatory change, and energy market conditions significantly impact our business. In response, we regularly evaluate our strategies with these goals in mind: to improve our competitive position, to anticipate and adapt to the business environment and regulatory changes, and to maintain a strong balance sheet and investment-grade credit quality through the use of a business model that applies cash flow to reduce debt.

While we pursue the above strategy with Generation and Customer Supply activities, we are continuing a disciplined approach to the management of our collateral requirements and liquidity, including:

- pricing new business to reflect the full cost of capital in the current economic environment,
- balancing operating cash flows with earnings growth,
- maintaining a liquidity cushion in excess of credit-rating downgrade collateral requirements and market stress conditions,
- using proceeds from the sale of a 49.99% membership interest in CENG to EDF to reduce our debt and maintain credit metrics consistent with investment grade ratings to support our Customer Supply operations, and
- focusing on Constellation Energy's core strengths of:
  - owning, developing, and operating generation assets,
  - providing reliable, regulated utility service to customers,
  - leveraging our expertise in managing physical risks inherent in our Generation and Customer Supply operations, and
  - maintaining strong supply relationships with retail and wholesale customers.

We are also in the forefront of the proposed development of new nuclear generation in the United States through our UniStar Nuclear Energy (UNE) joint venture with EDF. EDF brings operational experience, global scale, and procurement leverage to the development of new nuclear plants in the United States.

Business Environment

Various factors affect our financial results. We discuss some of these factors in more detail in *Item 1. Business—Competition* section. We also discuss these various factors in the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

Throughout 2008, volatility in the financial markets intensified, leading to dramatic declines in equity prices and substantially reducing liquidity in the credit markets. Most equity indices declined significantly, the cost of credit default swaps and bond spreads increased substantially, and credit markets effectively ceased to be accessible for all but the most highly rated borrowers. In 2009, markets in which we operate were affected by declining prices for power, gas, and capacity.

During 2009, we improved our liquidity and reduced our business risk in response to these market events. We discuss our liquidity and collateral requirements in the *Financial Condition* section. We continue to actively manage our credit risk to attempt to reduce the impact of a potential counterparty default. We discuss our customer (counterparty) credit and other risks in more detail in the *Risk Management* section. Competition impacts our business.

We discuss merchant competition in more detail in *Item 1. Business—Competition* section. The impacts of electric deregulation on BGE in Maryland are discussed in *Item 1. Business—Baltimore Gas and Electric Company—Electric Business—Electric Competition* section.

Regulation—Maryland

Maryland PSC

In addition to electric restructuring, which we discuss in *Item 1. Business—Electric Competition section*, regulation by the Maryland Public Service Commission (Maryland PSC) significantly influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers of its electric distribution and gas businesses. The Maryland PSC incorporates into BGE's standard offer service rates the transmission rates determined by the Federal Energy Regulatory Commission (FERC). BGE's electric rates are unbundled in customer billings to show separate components for delivery service (i.e. base rates), electric supply (commodity charge and transmission), and certain taxes and surcharges. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rates as well as certain taxes and surcharges) and a commodity charge.

Order Approving Transaction with EDF

In October 2009, the Maryland PSC issued an order approving our transaction with EDF subject to the following conditions, with which both Constellation Energy and EDF are complying:

- Constellation Energy is to fund a one-time per customer distribution rate credit for BGE residential customers, before the end of March 2010, totaling $110.5 million, or approximately $100 per customer, for which we recorded a liability and corresponding reduction in regulated electric and gas revenues in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating we would give residential customers a rate credit of exactly $100 per customer. As a result, we accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. Constellation Energy made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.
- Constellation Energy is required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this equity contribution to BGE in December 2009.
- BGE will not pay common dividends to Constellation Energy if:
  - after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents, or
  - BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.
- BGE may file an electric and/or gas distribution rate case at any time beginning in January 2010 and may not file a subsequent electric and/or gas distribution rate case until January 2011. Any rate increase in the first electric distribution rate case will be capped at 5% as

agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. BGE plans to file an electric and gas distribution rate case in the second quarter of 2010.
- Constellation Energy will be limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.
- Constellation Energy and BGE are required to implement "ring fencing" measures designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy to hold all of the common equity interests in BGE. We completed the implementation of these measures in February 2010.

Maryland Settlement Agreement

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory, and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

- Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC closed ongoing proceedings relating to the 1999 settlement.
- BGE provided its residential electric customers approximately $189 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.
- BGE customers are relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2, scheduled to begin no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1, which was enacted in June 2006.
- BGE resumed collection of the residential return portion of the administrative charge included in Standard Offer Service (SOS) rates, which had been eliminated under Senate Bill 1, on June 1, 2008 and will continue collection through May 31, 2010 without having to rebate it to all residential electric customers. This will total approximately $40 million over this period. This charge will be suspended from June 1, 2010 through December 31, 2016.
- Any increase in electric distribution revenue awarded in the first electric distribution rate case filed by BGE after the settlement will be capped at 5% with certain exceptions. The agreement does not govern or affect our ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases, or increases associated with standard offer service power supply auctions.
- Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense by approximately $14 million in 2008 and $25.2 million in 2009 without impacting distribution rates charged to customers.
- Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.
- Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

Senate Bills 1 and 400

In June 2006, Maryland Senate Bill 1 was enacted, which among other things:

- imposed rate stabilization measures that (i) capped rate increases by BGE for residential SOS service at 15% from July 1, 2006 to May 31, 2007, (ii) gave residential SOS customers the option from June 1, 2007 until December 31, 2007 of paying a full market rate or choosing a short term rate stabilization plan in order to provide a smooth transition to market rates without adversely affecting the creditworthiness of BGE, and (iii) provided for full market rates for all residential SOS service starting January 1, 2008; and
- allowed BGE to recover the costs deferred from July 1, 2006 to May 31, 2007 from its customers over a period not to exceed 10 years, on terms and conditions to be determined by the Maryland PSC, including through the issuance of rate stabilization bonds that securitize the deferred costs.

In connection with these provisions of Senate Bill 1:

- In May 2007, the Maryland PSC approved a plan to allow residential electric customers to defer the transition to full market rates from June 1, 2007 to January 1, 2008. The 4 percent of customers who chose to defer are repaying the deferred amounts without interest over a twenty-one month period which began on April 1, 2008.
- In June 2007, a subsidiary of BGE issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover costs relating to the residential rate deferral from July 1, 2006 to May 31, 2007. We discuss

the rate stabilization bond issuance in more detail in *Note 9 to Consolidated Financial Statements*.

In April 2007, Maryland Senate Bill 400 was enacted, which made certain modifications to Senate Bill 1. Pursuant to Senate Bill 400, the Maryland PSC was required to initiate several studies, including studies relating to stranded costs, the costs and benefits of various options for re-regulation, and the structure of the electric industry in Maryland.

In December 2007, the Maryland PSC issued an interim report addressing the costs and benefits of various options for re-regulation and recommending actions to be taken to address an anticipated shortage of generation and transmission capacity in Maryland, which included implementation of demand response initiatives and requiring utilities to enter into long-term power purchase contracts with suppliers.

The Maryland PSC issued a final report in December 2008. In the final report, the Maryland PSC did not recommend returning the former utility generation assets to full cost of service regulation, but rather recommended incremental, forward looking re-regulation when appropriate to ensure a reliable supply of electricity or to obtain economic benefits for customers. In 2009, the Maryland PSC continued to examine how to procure electric supply for Maryland residents, from modifications to the existing auction process to requiring that new generation be built by the utilities or by third parties. We cannot at this time predict the ultimate outcome of these inquiries, studies, and recommendations or their actual effect on our, or BGE's financial results, but it could be material.

We discuss the market risk of our regulated electric business in more detail in the *Risk Management* section.

Base Rates

Base rates are the rates the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery service, plus a profit. BGE has both electric base rates and gas base rates.

BGE may ask the Maryland PSC to increase base rates from time to time, subject to limitations in the Maryland PSC's October 2009 order approving our transaction with EDF. The Maryland PSC historically has allowed BGE to increase base rates to recover its utility plant investment and operating costs, plus a profit. Generally, rate increases improve the earnings of our regulated business because they allow us to collect more revenue. However, rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

BGE's most recently approved return on electric distribution rate base was 9.4% (approved in 1993). BGE's most recently approved return on gas rate base was 8.49% (approved in 2005).

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings. We have a similar revenue decoupling mechanism in our gas business.

Demand Response and Advanced Metering Programs

In order to implement an advanced metering pilot program and a demand response program, BGE defers costs associated with these programs as a regulatory asset and recovers these costs from customers in future periods. We discuss the advanced metering and demand response programs in more detail in *Item 1. Business—Baltimore Gas and Electric Company—Electric Load Management*.

Electric Commodity and Transmission Charges

We discuss BGE electric commodity and transmission charges (standard offer service), including the impact of the enactment of Senate Bill 1 in Maryland, in the *Business Environment—Regulation—Maryland—Senate Bills 1 and 400* section.

Gas Commodity Charge

BGE charges its gas customers separately for the natural gas they purchase. The price BGE charges for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates in more detail in the *Regulated Gas Business—Gas Cost Adjustments* section and in *Note 6 to Consolidated Financial Statements.*

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including electric transmission and wholesale natural gas and electricity sales. BGE transmission rates are updated annually based on a formula methodology approved by FERC. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007. We believe that FERC's continued commitment to fair and efficient wholesale energy markets should continue to result in improvements to competitive markets across various regions.

Since 1997, operation of BGE's transmission system has been under the authority of PJM Interconnection (PJM), the Regional Transmission Organization (RTO) for the Mid-Atlantic region, pursuant to FERC oversight. As the transmission operator, PJM administers the energy markets and conducts day-to-day operations of the bulk power system. The liability of transmission owners, including BGE, and power generators is limited to those damages caused by the gross negligence of such entities.

In addition to PJM, RTOs exist in other regions of the country such as the Midwest, New York, and New England. Similar to PJM, these RTOs also administer the energy market for their region and are responsible for operation of the transmission system and transmission system reliability. Our merchant energy business participates in these regional energy markets. These markets are continuing to develop, and revisions to market structure are subject to review and approval by FERC. We cannot predict the outcome of any reviews at this time. However, changes to the structure of these markets could have a material effect on our financial results.

FERC Initiatives

Ongoing initiatives at FERC have included a review of its methodology for the granting of market-based rate authority to sellers of electricity. FERC has established interim tests that it uses to determine the extent to which companies may have market power in certain regions. Where FERC finds that market power exists, it may require companies to implement measures to mitigate the market power in order to maintain market-based rate authority. We believe that our entities selling wholesale power continue to satisfy FERC's test for determining whether to grant a public utility market-based rate authority.

In November 2004, FERC eliminated through and out transmission rates between the Midwest Independent System Operator (MISO) and PJM and put in place Seams Elimination Charge/Cost Adjustment/Assignment (SECA) transition rates, which are paid by the transmission customers of MISO and PJM and allocated among the various transmission owners in PJM and MISO. The SECA transition rates were in effect from December 1, 2004 through March 31, 2006. FERC set for hearing the various compliance filings that established the level of the SECA rates and has indicated that the SECA rates are being recovered from the MISO and PJM transmission customers subject to refund by the MISO and PJM transmission owners.

We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. Administrative hearings regarding the SECA charges concluded in May 2006, and an initial decision from the FERC administrative law judge (ALJ) was issued in August 2006. The decision of the ALJ generally found in favor of reducing the overall SECA liability. The decision, if upheld, is expected to significantly reduce the overall SECA liability at issue in this proceeding. However, the ALJ also allowed SECA charges to be shifted to upstream suppliers, subject to certain adjustments. Therefore, certain charges could be shifted to our Global Commodities operation. FERC has stated that it would issue a substantive order on the ALJ's decision no later than the end of May 2010. Nonetheless, the amounts collected under the SECA rates are subject to refund and the ultimate outcome of the proceeding establishing SECA rates is uncertain. Depending on the ultimate outcome, the proceeding may have a material effect on our financial results.

Capacity Markets

In general, capacity market design revisions are routinely proposed and considered on an ongoing basis. Such changes are subject to FERC's review and approval. Currently, we cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results.

Through 2008 and 2009, PJM made several filings at FERC proposing various revisions to its capacity market, or Reliability Pricing Model (RPM), including the determination of the cost-of-new-entry (CONE), which is an important component in determining the price paid to capacity resources in PJM. PJM also proposed revisions relating to the participation of energy efficiency and demand resources, and market power and mitigation rules. Some of these matters are still pending at FERC. While recent RPM design changes have not yet had a material effect on our financial results, we cannot predict the outcome of the issues still pending or on any capacity market design changes that result from new regulatory requirements. Such changes could have a material impact on our financial results.

In May 2008, five state public service commissions, including the Maryland PSC, consumer advocates, and others filed a complaint against PJM at the FERC, alleging that the RPM produced unreasonable prices during the period from June 1, 2008 through May 31, 2011. The complaint requests that FERC establish a refund effective date of June 1, 2008, reject the results of the 2007/08 through 2010/11 RPM capacity auction results, and significantly reduce prices for capacity beginning as of June 1, 2008 through 2011/12. In September 2008, FERC dismissed the complaint and in October 2008, the complainants requested a rehearing at FERC. FERC denied rehearing and ultimately the case was appealed and is pending before the United States Court of Appeals for the District of Columbia. We cannot predict the outcome of this proceeding or the amount of refunds that may be owed by or due to us, if any. However, the outcome, and any refunds that are ultimately assessed, could have a material impact on our financial results.

In April 2009, the Attorney General of Connecticut, the Connecticut Department of Public Utilities and Office of Consumer Counsel (together, the Connecticut Parties) filed complaints at FERC alleging improper energy bidding behavior since December 1, 2006 by generators located in New York that also received capacity payments within ISO-New England. In May 2009, the Connecticut Parties filed an amended complaint asserting that Constellation Energy Commodities Group, Inc. (CCG) and others received capacity payments while never intending to perform as capacity resources. The revised allegations assert that certain generators engaged in "economic withholding" by submitting energy bids at or near the offer cap. Since December 2006, CCG has received approximately $7 million in payments for capacity offered into ISO-New England associated with Constellation Energy's nuclear facilities located in NY. In August 2009, FERC issued an order setting this matter for a public hearing before an ALJ to determine the intent of the capacity suppliers (including CCG) in making their energy offers in ISO-New England. CCG is participating in the administrative hearing, which is ongoing and has maintained its adherence to all applicable rules and regulations relating to the market activity. However, we cannot predict the outcome of the FERC hearing or any potential liability that CCG may incur.

Three major, high-voltage transmission lines have been announced that could enhance significantly the transfer capacity of the PJM transmission system from west to east. The siting process, both in the states and at FERC, is uncertain, as is the likelihood that one or more of the transmission lines will be ultimately constructed. The construction of the transmission lines, which could depress both capacity and energy prices for generation located in Maryland and elsewhere in the eastern part of PJM, could have a material effect on our financial results.

NERC Reliability Standards
In compliance with the Energy Policy Act of 2005, FERC has approved the North American Electric Reliability Corporation (NERC) as the national energy reliability organization. NERC will be responsible for the development and enforcement of mandatory reliability and cyber-security standards for the wholesale electric power system. We are responsible for complying with the standards in the regions in which we operate. NERC will have the ability to assess financial penalties for noncompliance, which could be material.

Given the increasing concern over the security of the country's energy infrastructure, there could be future rules or regulations related to the operation and security requirements of our generating facilities and electric and gas transmission and distribution systems, which could have a material impact on our operations and financial results.

Commodity Futures Trading Commission
The United States Congress and the Commodity Futures Trading Commission (CFTC) are evaluating additional laws and regulations for the derivatives markets, including position limits and eliminating regulatory exemptions for hedging activity. We are unable to determine the final form any regulations or new laws may take, but such laws or regulations could have a material effect on our business.

Market Oversight
Regulatory agencies that have jurisdiction over our businesses, including the FERC and CFTC, possess broad enforcement and investigative authority to ensure well functioning markets and to prohibit market manipulation or violations of the agencies' rules or orders. These agencies also possess significant civil penalty authority, including in the case of FERC and the CFTC, the authority to impose a penalty of up to $1 million per day per violation. We are committed to a culture of compliance and ensuring compliance with all applicable rules, laws and orders. Nonetheless, the regulatory agencies engage in either public or non-public investigations in response to allegations of wrongdoing and we may be involved in certain market activities that become subject to investigations. Even where no wrongdoing is found, the process of participating in a regulatory investigation could have a material effect on our business.

Weather

Merchant Energy Business
Weather conditions in the different regions of North America influence the financial results of our merchant energy business. Weather conditions can affect the supply of and demand for electricity, natural gas, and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market, which may affect our results in any given period. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. The demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time, thus we are not typically exposed to the effects of extreme weather in all parts of our business at once.

BGE
Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Weather affects residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas. The Maryland PSC has approved revenue decoupling mechanisms which allow BGE to record monthly adjustments to the majority of our regulated electric and gas business distribution revenues to eliminate the effect of abnormal weather and usage patterns. We discuss this further in the *Regulation—Maryland PSC—Revenue Decoupling, Regulated Electric Business—Revenue Decoupling* and *Regulated Gas Business—Revenue Decoupling* sections.

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for our merchant energy business. These factors include:

- seasonal, daily, and hourly changes in demand,
- number of market participants,
- extreme peak demands,
- available supply resources,
- transportation and transmission availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- implementation of new market rules governing operations of regional power pools,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- international supply and demand.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions,

- market liquidity,
- capability and reliability of the physical electricity and gas systems,
- local transportation systems, and
- the nature and extent of electricity deregulation.

Other factors also impact the demand for electricity and gas in our regulated businesses. These factors include the number of customers and usage per customer during a given period. We use these terms later in our discussions of regulated electric and gas operations. In those sections, we discuss how these and other factors affected electric and gas sales during the periods presented.

The number of customers in a given period is affected by new home and apartment construction and by the number of businesses in our service territory.

Usage per customer refers to all other items impacting customer sales that cannot be measured separately. These factors include the strength of the economy in our service territory. When the economy is healthy and expanding, customers tend to consume more electricity and gas. Conversely, during an economic downturn, our customers tend to consume less electricity and gas.

Environmental Matters and Legal Proceedings

We discuss details of our environmental matters in *Note 12 to Consolidated Financial Statements* and *Item 1. Business—Environmental Matters* section. We discuss details of our legal proceedings in *Note 12 to Consolidated Financial Statements*. Some of this information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in *Note 1 to Consolidated Financial Statements*.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations is based on our consolidated financial statements that were prepared in accordance with accounting principles generally accepted in the United States of America. Management makes estimates and assumptions when preparing financial statements. These estimates and assumptions affect various matters, including:

- our reported amounts of revenues and expenses in our Consolidated Statements of Income (Loss),
- our reported amounts of assets and liabilities in our Consolidated Balance Sheets, and
- our disclosure of contingent assets and liabilities.

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual amounts could materially differ from these estimates.

Management believes the following accounting policies represent critical accounting policies as defined by the Securities and Exchange Commission (SEC). The SEC defines critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results of operations and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1 to Consolidated Financial Statements*.

Accounting for Derivatives and Hedging Activities

We utilize a variety of derivative instruments in order to manage commodity price risk, interest rate risk, and foreign currency risk. Because of the extensive nature of the accounting requirements that govern both accounting treatment and documentation, as well as the complexity of the transactions within its scope, management is required to exercise judgment in several areas, including the following:

- identification of derivatives,
- selection of accounting treatment for derivatives,
- valuation of derivatives, and
- impact of uncertainty.

As discussed in more detail below, the exercise of management's judgment in these areas materially impacts our financial statements. While we believe we have appropriate controls in place to apply the derivative accounting requirements, failure to meet these requirements, even inadvertently, could require the use of a different accounting treatment for the affected transactions. In addition, interpretations of these accounting requirements continue to evolve, and future changes in accounting requirements also could affect our financial statements materially. We discuss derivatives and hedging activities in more detail in *Note 1* and *Note 13 to Consolidated Financial Statements*.

Identification of Derivatives

We must evaluate new and existing transactions and agreements to determine whether they are derivatives. Identifying derivatives requires us to exercise judgment in interpreting the definition of a derivative and applying that definition to each individual contract. If a contract is not a derivative, we cannot apply derivative accounting, and we generally must record the effects of the contract in our financial statements upon delivery or settlement under the accrual method of accounting. In contrast, if a contract is a derivative, we must apply derivative accounting, which provides for several possible accounting treatments as discussed more fully under *Accounting Treatment* below. As a result, the required accounting treatment and its impact on our financial statements can vary substantially depending upon whether a contract is a derivative or a non-derivative.

Accounting Treatment

We are permitted several possible accounting treatments for derivatives that meet all of the applicable requirements. Mark-to-market is the default accounting treatment for all derivatives unless they qualify, and we affirmatively designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

The permissible accounting treatments for derivatives are:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- accrual accounting under Normal Purchase/Normal Sale (NPNS).

Each of the accounting treatments that we use for derivatives affects our financial statements in substantially different ways as summarized below:

Accounting Treatment	Recognition and Measurement	
	Balance Sheet	**Income Statement**
Mark-to-market	◆ Derivative asset or liability recorded at fair value	◆ Changes in fair value recognized in earnings
Cash flow hedge	◆ Derivative asset or liability recorded at fair value ◆ Effective changes in fair value recognized in accumulated other comprehensive income	◆ Ineffective changes in fair value recognized in earnings ◆ Amounts in accumulated other comprehensive income reclassified to earnings when the hedged forecasted transaction affects earnings or becomes probable of not occurring
Fair value hedge	◆ Derivative asset or liability recorded at fair value ◆ Book value of hedged asset or liability adjusted for changes in its fair value	◆ Changes in fair value recognized in earnings ◆ Changes in fair value of hedged asset or liability recognized in earnings
NPNS (accrual)	◆ Fair value not recorded ◆ Accounts receivable or accounts payable recorded when derivative settles	◆ Changes in fair value not recognized in earnings ◆ Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

We exercise judgment in determining which derivatives qualify for a particular accounting treatment, including:

- Cash flow and fair value hedges—determination that all hedge accounting requirements are satisfied, including the expectation that the derivative will be highly effective in offsetting changes in cash flows or fair value from the risk being hedged and, for cash flow hedges, the probability that the hedged forecasted transaction will occur.
- Accrual accounting under NPNS—determination that the derivative will result in gross physical delivery of the underlying commodity and will not settle net.

We also exercise judgment in selecting the accounting treatment that we believe provides the most transparent presentation of the economics of the underlying transactions. Although contracts may be eligible for hedge accounting or NPNS designation, we are not required to designate and account for all such contracts identically. We generally elect accrual or hedge accounting for our physical energy delivery activities (generation and customer supply) because accrual accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. By contrast, we generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for the following physical energy delivery activities:

- our nonregulated retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges so as to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

As a result of making these judgments, the selection of accounting treatments for derivatives has a material impact on our financial position and results of operations. These impacts affect several components of our financial statements, including assets, liabilities, and accumulated other comprehensive income (AOCI). Additionally, the selection of accounting treatment also affects the amount and timing of the recognition of earnings. The following table summarizes these impacts:

Effect of Changes in Fair Value on:	Accounting Treatment			
	Mark-to-market	**Cash Flow Hedge**	**Fair Value Hedge**	**NPNS**
Assets and liabilities	◆ Increase or decrease in derivatives	◆ Increase or decrease in derivatives	◆ Increase or decrease in derivatives ◆ Decrease or increase in hedged asset or liability	◆ No impact
AOCI	◆ No impact	◆ Increase or decrease for effective portion of hedge	◆ No impact	◆ No impact
Earnings prior to settlement	◆ Increase or decrease	◆ Increase or decrease for ineffective portion of hedge	◆ Increase or decrease for change in derivatives ◆ Decrease or increase for change in hedged asset or liability ◆ Increase or decrease for ineffective portion	◆ No impact
Earnings at settlement	◆ No impact	◆ Amounts in AOCI reclassified to earnings when hedged forecasted transaction affects earnings or when the forecasted transaction becomes probable of not occurring	◆ Hedged margin recognized in earnings	◆ Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Valuation

We record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. In these cases, we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels. We discuss fair value measurements in more detail in *Note 13 to Consolidated Financial Statements*.

The judgments we are required to make in order to estimate fair value have a material impact on our financial statements. These judgments affect the selection, appropriateness, and application of modeling techniques, the methods used to identify or estimate inputs to the modeling techniques, and the consistency in applying these techniques over time and across types of derivative instruments. Changes in one or more of these judgments could have a material impact on the valuation of derivatives and, as a result, could also have a material impact on our financial position or results of operations.

Impacts of Uncertainty

The accounting for derivatives and hedging activities involves significant judgment and requires the use of estimates that are inherently uncertain and may change in subsequent periods. The effect of changes in assumptions and estimates could materially impact our reported amounts of revenues and costs and could be affected by many factors including, but not limited to, the following:

- uncertainty surrounding inputs to the estimates of fair value due to factors such as illiquid markets or the absence of observable market price information,
- our ability to continue to designate and qualify derivative contracts for NPNS accounting or hedge accounting,
- potential volatility in earnings from ineffectiveness on derivatives for which we have elected hedge accounting, and
- our ability to enter into new mark-to-market derivative origination transactions.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

Long-Lived Assets

We are required to evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. We are required to test our long-lived assets for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes are:

- a significant decrease in the market price of a long-lived asset,
- a significant adverse change in the manner an asset is being used or its physical condition,
- an adverse action by a regulator or legislature or an adverse change in the business climate,
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- a current-period loss combined with a history of losses or the projection of future losses, or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

For long-lived assets classified as held for sale, we recognize an impairment loss to the extent their carrying amount exceeds their fair value less costs to sell. For long-lived assets that we expect to hold and use, we recognize an impairment loss only if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable if it exceeds the total undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we estimate the undiscounted future cash flows associated with the asset at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. This necessarily requires us to estimate uncertain future cash flows.

In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the cash flows.

We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. The estimation of fair value also involves judgment. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers, or employ other valuation techniques. Often, we will discount the estimated future cash flows associated with the asset using a single interest rate that is commensurate with the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as discussed above with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates, and the impact of such variations could be material.

Gas Properties

We evaluate unproved property at least annually to determine if it is impaired. Impairment for unproved property occurs if there are no firm plans to continue drilling, the lease is near its expiration, or historical experience necessitates a valuation allowance.

Investments

We evaluate our equity-method and cost-method investments (for example, CENG, UNE, CEP and partnerships that own power projects) to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

The evaluation and measurement of investment impairments involves the same uncertainties as described above for long-lived assets that we own directly. Similarly, the estimates that we make with respect to our equity and cost-method investments are subject to variation, and the impact of such variations could be material. Additionally, if the projects in which we hold these investments recognize an impairment, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity-method investments that own geothermal, coal, hydroelectric, fuel processing projects, as well as our equity investments in our nuclear joint ventures and CEP. These issues include environmental and legislative initiatives as well as events that will impact the viability of new nuclear development. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* and *Item 1A. Risk Factors* sections. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired.

Current California statutes and regulations require load-serving entities to increase their procurement of renewable energy resources and mandate statewide reductions in greenhouse gas emissions. Given the need for electric power and the statutory and regulatory requirements increasing demand for renewable resource technologies, we believe California will continue to foster an environment that supports the use of renewable energy and continues certain subsidies that will make renewable energy projects economical. However, should California legislation and regulatory policies and federal energy policies fail to adequately support renewable energy initiatives, our equity-method investments in these types of projects could become impaired, and any losses recognized could be material.

Debt and Equity Securities

Our available for sale investments in debt and equity securities are subject to impairment evaluations. Our most significant available for sale securities were the nuclear decommissioning trust fund assets. However, upon the completion of our transaction with EDF on November 6, 2009, we no longer reflect the nuclear decommissioning trust fund assets on our Consolidated Balance Sheets. To the extent that CENG impairs its nuclear decommissioning trust fund assets, we will report our share of the impairment as part of our equity investment earnings in CENG.

We determine whether a decline in fair value of an investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis. For securities held in our nuclear decommissioning trust fund through November 6, 2009 for which the market value was below book value, the decline in fair value for these securities was considered other than temporary, and the securities were written down to fair value.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We do not amortize goodwill. We evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as discussed on the previous page, which involves judgment. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value.

Significant Events

Sale of 49.99% Membership Interest in CENG to EDF

On November 6, 2009, we sold a 49.99% membership interest in CENG, our nuclear generation and operation business. The following summarizes where we disclose the significant impacts of this transaction on us:

- We provide an overview of this transaction in *Item 1. Business section.*
- Upon the close of this transaction, we deconsolidated CENG and recorded our initial investment in CENG on our Consolidated Balance Sheets. We discuss the significant changes as a result of recording the transaction and the deconsolidation of CENG on our Consolidated Balance Sheets and the expected impact on our ongoing financial results and cash flows in this section.
- As a result of recording the transaction, we have presented certain additional line items on our consolidated financial statements in *Item 8,* such as our investment in CENG, the gain on sale, and the proceeds received from the transaction.
- We recorded a significant gain on the sale of the 49.99% membership interest as well as on our retained interest at transaction close. The fair value of our investment in CENG exceeded our share of CENG's equity because CENG's assets and liabilities retained their historical carrying value. This basis difference will be amortized as a reduction to our future equity in earnings of CENG. We discuss this item in Notes *2 and 4 to Consolidated Financial Statements.*
- We discuss the Maryland PSC order approving the transaction in *Note 2 to Consolidated Financial Statements.*
- The closing of the transaction impacted our credit facilities and, therefore, our net available liquidity. We discuss our net available liquidity in this section.
- A portion of the proceeds received from the transaction will be used to retire approximately $1 billion of debt prior to its maturity. We discuss our debt retirements to date in Note 9 *to Consolidated Financial Statements.*
- Given the significance of our investment in CENG, we are exposed to many of the same risks as CENG. CENG is exposed to risks associated with operating nuclear generating facilities and the risk of a nuclear accident. We discuss our exposure to certain of these risks in *Note 12 to Consolidated Financial Statements.*
- We entered into the following agreements with CENG:
  - a power purchase agreement,
  - a power services agency agreement, and
  - an administrative services agreement.

  We discuss the nature and purpose of these agreements in *Note 16 to Consolidated Financial Statements.*

BGE Residential Customer Rate Credit

On October 30, 2009, as part of the order approving our transaction with EDF, the Maryland PSC required Constellation Energy to fund a one-time distribution rate credit to be given to BGE residential customers before the end of March 2010 totaling $110.5 million, or approximately $100 per customer. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a distribution rate credit of exactly $100 per customer. We recorded the total credit of $112.4 million in the fourth quarter of 2009 and will apply it to customer bills in the first quarter of 2010 as required under the order. Constellation Energy made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as required by the Maryland PSC order approving the transaction with EDF. We discuss BGE's residential customer rate credit in *Note 2 to Consolidated Financial Statements.*

Contribution to BGE

On October 30, 2009, as part of the order approving our transaction with EDF, the Maryland PSC required Constellation Energy to provide a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this contribution in December 2009.

Acquisitions

In July 2009, we acquired CLT Efficient Technologies Group (CLT), an energy services company.

On November 30, 2009, we signed an agreement to acquire the Criterion wind project in Garrett County, Maryland.

We discuss these acquisitions in more detail in *Note 15 to Consolidated Financial Statements*.

Divestitures

During 2009, we completed the following divestitures:

Operation	Closing Date
Majority of our international commodities operation	March 2009
Gas and other trading operations (1)	April 2009
Uranium market participant	June 2009
Shipping joint venture investment	August 2009
District energy facility	December 2009

(1) Simultaneously with this divestiture, we entered into an agreement with the buyer to provide us with the gas supply needed to support our retail gas customer supply operations.

We discuss these divestitures and the gas supply agreement in more detail in the *Note 2 to Consolidated Financial Statements*.

Merger Termination and Strategic Alternatives Costs

Throughout 2009, we incurred merger termination and strategic alternatives costs related to the terminated merger with MidAmerican Energy Holdings Company (MidAmerican) in 2008, the conversion of our Series A Preferred Stock into a note, the transactions related to EDF, and other strategic alternatives costs. We discuss costs related to the mergers and strategic alternatives in more detail in *Note 2 to Consolidated Financial Statements*.

Impairment Losses and Other Costs

Throughout 2009, we recorded impairment losses and other costs on certain of our equity method investments, investments in equity securities and other assets. We discuss these charges in more detail in the *Note 2 to Consolidated Financial Statements*.

Workforce Reduction Costs

During 2009, we incurred workforce reduction costs primarily related to the divestiture of a majority of our international commodities operation as well as other smaller restructurings elsewhere in our organization. We recognized a $12.6 million pre-tax charge in 2009 related to the elimination of approximately 180 positions. We expect all of these restructurings will be completed within 12 months from the program's initiation. We discuss our workforce reduction costs in more detail in *Note 2 to Consolidated Financial Statements*.

Redemption of Notes

In the fourth quarter of 2009, we redeemed our Zero Coupon Senior Notes early and recognized a pre-tax loss of $16.0 million.

In February 2010, we retired certain of our 7.00% Notes due April 1, 2012 as part of a cash tender offer launched in January 2010 and issued call notices to retire certain tax exempt notes.

We discuss these transactions in more detail in *Note 9 to Consolidated Financial Statements*.

Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, and then separately discuss earnings for our operating segments. Significant changes in other income (expense), fixed charges, and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section.

As discussed in *Item 1 Business—Overview* section and in the *Strategy* and *Significant Events* sections, Constellation Energy's 2009 and 2008 operating results were materially impacted by a number of significant events, transactions, and changes in our strategic direction. The impact of these items has affected the comparability of our 2009 and 2008 results to prior periods and will alter Constellation Energy's operating results in the future. In this section, we highlight the 2009 and 2008 impacts of these items.

Overview

Results

	2009	2008	2007
	(In millions, after-tax)		
Net income (loss):			
Merchant energy	**$4,435.0**	$(1,374.6)	$677.9
Regulated electric	**79.1**	11.1	107.9
Regulated gas	**25.5**	40.4	32.0
Other nonregulated	**(36.2)**	4.7	16.6
Income (Loss) from continuing operations and before cumulative effects of changes in accounting principles	**4,503.4**	(1,318.4)	834.4
Loss from discontinued operations	**—**	—	(0.9)
Net Income (Loss)	**$4,503.4**	$(1,318.4)	$833.5
Net Income (Loss) attributable to common stock	**$4,443.4**	$(1,314.4)	$821.5
Change from prior year	**$5,757.8**	$(2,135.9)	

Our total net income attributable to common stock for 2009 improved compared to 2008 by $5.8 billion, or $29.53 per share, mostly because of the following:

	Increase/(Decrease) 2009 vs. 2008
	(in millions, after-tax)
Generation gross margin	$ 38
Customer Supply gross margin	22
Global Commodities gross margin	(177)
Absence of sale of upstream gas assets	(16)
Hedge ineffectiveness	84
Absence of credit loss—coal supplier bankruptcy	33
Regulated businesses, excluding the effects of the 2008 Maryland settlement agreement and the 2009 residential customer credit	10
Other nonregulated businesses	(41)
Total change in *Other Items Included in Operations* per table below	5,763
All other changes	42
Total Change	$5,758

Our total net loss attributable to common stock for 2008 deteriorated compared to 2007 by $2.1 billion, or $11.84 per share, mostly because of the following:

	Increase/(Decrease) 2008 vs. 2007
	(in millions, after-tax)
Generation gross margin	$ 114
Customer Supply gross margin	(79)
Global Commodities gross margin	(121)
Sale of upstream gas assets	16
Absence of 2007 sale of CEP LLC equity	(39)
Hedge ineffectiveness	(26)
Credit loss—coal supplier bankruptcy	(33)
Merchant operating expenses excluding bad debt expense, primarily labor and benefit costs	57
Merchant bad debt expense	(19)
Merchant interest expense	(63)
Synthetic fuel facilities	(9)
Other nonregulated businesses	(12)
Interest and investment income	(35)
Total change in *Other Items Included in Operations* per table below	(1,966)
All other changes	79
Total Change	$(2,136)

Other Items Included in Operations (after-tax):

	2009	2008	2007
	(In millions, after-tax)		
Gain on sale of 49.99% interest in CENG	**$4,456.1**	$ —	$ —
Amortization of basis difference in CENG	**(17.8)**	—	—
International commodities operation and gas trading operation[1]	**(371.9)**	—	—
Impairment losses and other costs	**(96.2)**	(468.4)	(12.2)
Merger termination and strategic alternatives costs	**(13.8)**	(1,204.4)	—
Loss on redemption of Zero Coupon Senior Notes	**(10.0)**	—	—
BGE residential customer rate credit	**(67.1)**	—	—
Maryland settlement credit	**—**	(110.5)	—
Impairment of nuclear decommissioning trust assets	**(46.8)**	(82.0)	—
Emission allowance write down, net	**—**	(28.7)	—
Non-qualifying hedges	**—**	(70.1)	2.0
Credit facility amendment/ termination fees	**(37.7)**	—	—
Workforce reduction costs	**(9.3)**	(13.4)	(1.4)
Total Other Items	**$3,785.5**	$(1,977.5)	$(11.6)
Change from prior year	**$5,763.0**	$(1,965.9)	

(1) *These amounts include the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items also include amounts related to the operations we divested.*

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for various customers. We discuss the impact of deregulation on our merchant energy business in *Item 1. Business—Competition* section.

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets and customer supply activities, and uses our portfolio management and trading capabilities both to manage risk and to deploy limited risk capital.

At the beginning of 2009, we outlined various strategic initiatives to reduce risk for our Global Commodities operation. As of December 31, 2009, these initiatives have been completed. We discuss our current strategy in more detail in the *Strategy* section.

The execution of our strategy in the future may be affected by instability in financial, credit, and commodities markets. Execution of our goals could have a substantial effect on the nature and mix of our business activities.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect and based on the associated accounting policies. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and in *Note 1 to Consolidated Financial Statements*.

Our Global Commodities operation transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of these activities, we trade energy and energy-related commodities and deploy limited risk capital in the management of our portfolio in order to earn returns. We discuss the impact of our trading activities and economic value at risk in more detail in the *Mark-to-Market* and *Risk Management* sections.

Results

	2009	2008	2007
	(In millions)		
Revenues	**$12,433.5**	$ 16,690.5	$ 18,736.4
Fuel and purchased energy expenses	**(9,473.1)**	(13,791.4)	(15,501.8)
Operating expenses	**(1,534.2)**	(1,729.7)	(1,791.8)
Impairment losses and other costs	**(98.1)**	(741.8)	(20.2)
Workforce reduction costs	**(12.6)**	(15.4)	(2.3)
Merger termination and strategic alternatives costs	**(145.8)**	(1,204.4)	—
Depreciation, depletion, and amortization	**(250.2)**	(287.1)	(269.9)
Accretion of asset retirement obligations	**(62.3)**	(68.4)	(68.3)
Taxes other than income taxes	**(108.5)**	(124.3)	(110.2)
Equity investment earnings	**18.7**	82.3	8.1
Gain on sale of 49.99% interest in CENG	**7,445.6**	—	—
(Loss) gain on divestitures	**(464.2)**	25.5	—
Income (Loss) from Operations	**$ 7,748.8**	$ (1,164.2)	$ 980.0
Income (Loss) from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$ 4,435.0**	$ (1,374.6)	$ 677.9
Loss from discontinued operations (after-tax)	**—**	—	(0.9)
Net Income (Loss)	**$ 4,435.0**	$ (1,374.6)	$ 677.0
Net Income (Loss) attributable to common stock	**$ 4,381.0**	$ (1,357.4)	$ 678.3
Change from prior year	**$ 5,738.4**	$ (2,035.7)	
Other Items Included in Operations (after-tax):			
Gain on sale of 49.99% interest in CENG	**$ 4,456.1**	$ —	$ —
Amortization of basis difference in CENG	**(17.8)**	—	—
International commodities operation and gas trading operation (1)	**(371.9)**	—	—
Impairment losses and other costs	**(84.7)**	(468.4)	(12.2)
Merger termination and strategic alternatives costs	**(13.8)**	(1,204.4)	—
Loss on redemption of Zero Coupon Senior Notes	**(10.0)**	—	—
Impairment of nuclear decommissioning trust assets	**(46.8)**	(82.0)	—
Emission allowance write-down, net	**—**	(28.7)	—
Non-qualifying hedges	**—**	(70.1)	2.0
Credit facility amendment/ termination fees	**(37.7)**	—	—
Workforce reduction costs	**(9.3)**	(9.3)	(1.4)
Total Other Items	**$ 3,864.1**	$ (1,862.9)	$ (11.6)
Change from prior year	**$ 5,727.0**	$ (1,851.3)	

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

(1) Amount includes the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items also include amounts related to the operations we divested.

Effects of Transaction with EDF on Statement of Income (Loss)
Prior to November 6, 2009, CENG was a 100% owned subsidiary, and we consolidated its financial results within our Consolidated Statements of Income (Loss). On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, for the period from November 6, 2009 through December 31, 2009, we ceased recording CENG's financial results and began to record equity investment earnings from CENG as well as the effect of our PPA and other transactions with CENG. We discuss our transaction with EDF in more detail in *Note 2 to Consolidated Financial Statements.*

For the period from January 1, 2009 through November 6, 2009, our merchant energy results included the following financial results of CENG:

For the period from January 1, 2009 through November 6, 2009	
	(In billions)
Revenues	$1.2
Fuel and purchased energy expenses	0.1
Operating expenses	0.8
Depreciation and amortization	0.1
Income from operations	0.2

As a result of deconsolidation, we expect that our future merchant energy results will differ from historical results primarily due to the following factors:

- Revenues—We will sell between 85-90% of the output of CENG's plants, excluding output sold by CENG directly to third parties, rather than 100% of the plants' total output including volumes contracted to third parties.
- Fuel and purchased energy expenses—We will not include nuclear fuel expense but instead will reflect our purchase of between 85-90% of the output of CENG's plants, excluding output sold directly to third parties, as provided under the terms of the PPA with CENG.
- Operating expenses—We will no longer include CENG's plant operating costs or general and administrative expenses.
- Depreciation and amortization expense—We will no longer include deprecation of CENG's nuclear plants.

Additionally, we will record our 50.01% share of CENG's financial results and amortization of the CENG basis difference in the "Equity Investment (Losses) Earnings" line in our Consolidated Statements of Income (Loss). We discuss the accounting for our retained investment in CENG in more detail in *Note 2 to Consolidated Financial Statements.*

Revenues and Fuel and Purchased Energy Expenses
Our merchant energy business manages the revenues we realize from the sale of energy and energy-related products to our customers and our costs of procuring fuel and energy. The difference between revenues and fuel and purchased energy expenses, including all direct expenses, represents the gross margin of our merchant energy business, and this measure is a useful tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

In the third quarter of 2007, we changed the management of the wholesale procurement function for retail gas activities from our Customer Supply operations to our Global Commodities operation. In connection with this change, we began to prospectively account for the underlying retail gas contracts as derivative contracts subject to mark-to-market accounting, under which changes in fair value are recorded in revenues as they occur. This activity was previously accounted for on a gross basis and recorded in accrual revenues and fuel and purchased energy expenses. The change to mark-to-market accounting for this activity reduced both our accrual revenues and fuel and purchased energy expenses in 2008 and 2007. However, the change had a minimal impact on gross margin.

We discuss our merchant energy revenues, fuel and purchased energy expenses, and gross margin below.

Revenues

Our merchant energy revenues decreased $4,257.0 million in 2009 compared to 2008 and decreased $2,045.9 million in 2008 compared to 2007 primarily due to the following:

	2009 vs. 2008	2008 vs. 2007
	(In millions)	
Change in Global Commodities mark-to-market revenues due to changes in power and gas prices	**$ (215)**	$ (403)
Decrease in volume of business primarily related to our international coal and freight operation, which we have divested	**(647)**	—
Change in contract prices and volume of business primarily related to our divested international coal and freight operation	**—**	(281)
Change in contract prices and volumes related to our domestic coal operation	**280**	—
Realization of lower prices and volume of business at our gas trading operation, which we have divested, and absence of revenue due to the sales of certain of our upstream gas properties in 2008	**(283)**	—
Lower volumes of wholesale and retail load at our Global Commodities and Customer Supply operations, partially offset by higher contract prices	**(3,416)**	—
Realization of higher contract prices on wholesale and retail load at our Global Commodities and Customer Supply operations	**—**	658
All other (for 2008 vs. 2007, substantially all due to change in gas procurement activities)	**24**	(2,020)
Total decrease in merchant revenues	**$(4,257)**	$(2,046)

Fuel and Purchased Energy Expenses

Our merchant energy fuel and purchased energy expenses decreased $4,318.3 million in 2009 compared to 2008 and decreased $1,710.4 million in 2008 compared to 2007 primarily due to the following:

	2009 vs. 2008	2008 vs. 2007
	(In millions)	
Change in Global Commodities mark-to-market expenses related to international coal purchase contracts	**$ 218**	$ (106)
Decrease in volume of business primarily related to our international coal and freight operation, which we have divested	**(615)**	—
Change in contract prices and volume of business primarily related to our international coal and freight operation	**—**	(238)
Realization of lower volumes at our gas trading operations, which we have divested	**(220)**	—
Increase in contract prices and volume related to our domestic coal operation	**259**	—
Lower volumes on wholesale and retail power purchases at our Global Commodities and Customer Supply operations	**(3,956)**	—
Realization of higher contract prices on wholesale and retail purchases at our Global Commodities and Customer Supply operations	**—**	710
Decrease in synfuels expenses due to expiration of tax credits in 2007	**—**	(141)
All other (for 2008 vs. 2007, substantially all due to change in gas procurement activities)	**(4)**	(1,935)
Total decrease in merchant energy fuel and purchased energy expenses	**$(4,318)**	$(1,710)

Gross Margin

We analyze our merchant energy gross margin in the following categories.

- Generation—our operation that owns, operates, and maintains fossil, nuclear (through November 6, 2009), and renewable generating facilities and holds indirect interests in nuclear generating facilities (since November 6, 2009), qualifying facilities, and power projects in the United States. We present the gross margin results of this operation based on a 100% hedged assumption for the portfolio, related to both output from the facilities and the fuel used to generate electricity. The assumption is based on executing hedges at current market prices with the Global Commodities operation at the end of each prior fiscal year in order to ensure that the Generation operation is fully hedged. Therefore, all commodity price risk is managed by and presented in the results of our Global Commodities operation as discussed below. Changes in gross margin of our Generation operation during the period are due to changes in the level of output from the generating assets, and changes in gross margin between years are a result of changes in prices and expected output. Gross margin excludes our equity investment earnings from our nuclear joint ventures, qualifying facilities, and power projects. We discuss our treatment of equity investment earnings in more detail in *Note 1 to Consolidated Financial Statements*.
- Customer Supply—our load-serving operation that provides energy products and services to wholesale and retail electric and natural gas customers, including distribution utilities, cooperatives, aggregators, and commercial, industrial and governmental customers. We present the gross margin results of this operation based on the gross margin value of new customer supply arrangements at the time of execution assuming an estimated level of customer usage and the impact of any changes in the underlying usage of the customers based on actual energy deliveries including decreased demand related to the current economic environment. Changes in estimated customer usage result from attrition (customers changing suppliers) or variable load risk (changes in actual usage when compared to expected usage). All commodity price risk is presented in and managed by our Global Commodities operation.
- Global Commodities—our marketing, risk management, and trading operation that manages contractually owned physical assets, including generation facilities and natural gas properties, provides risk management services, and trades energy and energy-related commodities. This operation provides the wholesale risk management function for our Generation and Customer Supply operations, as well as our structured products and energy investments portfolios, and includes our merchant energy business' actual hedged positions with third parties. Therefore, changes in gross margin for this operation result mostly from changes in commodity prices and positions across the various commodities and regions in which we transact.

We provide a summary of our gross margin for these three components of our merchant energy business as follows:

	2009		2008		2007	
	(Dollar amounts in millions)					
		% of Total		% of Total		% of Total
Gross margin:						
Generation	$1,976	67%	$1,919	66%	$1,698	53%
Customer Supply	799	27	765	26	889	27
Global Commodities	185	6	215	8	648	20
Total	$2,960	100%	$2,899	100%	$3,235	100%

Generation

The $57 million increase in Generation gross margin in 2009 compared to 2008 is primarily due to the following:

- $178 million increase from higher energy prices for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2008 (see Global Commodities discussion below for impact of price changes during 2009), and
- $130 million due to the timing and duration of planned and unplanned outages at our generating plants.

These increases were partially offset by the following:

- $245 million of lower gross margin on our nuclear fleet as a result of the deconsolidation of CENG following the sale of a 49.99% membership interest to EDF on November 6, 2009, and
- $6 million of lower gross margin primarily related to our investments in power projects.

The $221 million increase in Generation gross margin in 2008 compared to 2007 is primarily due to the following:

- $210 million increase from higher energy prices for the output of our generating assets in the PJM and New York regions based on prices established at the end of 2007 (see Global Commodities discussion below for impact of price changes during 2008), and
- $11 million of higher earnings for lower planned and unplanned outages at our nuclear and fossil plants.

In 2010, our gross margin for Generation will be lower than in 2009 as a result of the sale of a 49.99% membership interest in CENG to EDF on November 6, 2009.

Customer Supply

The $34 million increase in Customer Supply gross margin in 2009 compared to 2008 is primarily due to the following:

- $108 million of higher gross margin mostly related to the consolidation of a retail power supply variable interest entity for which we became the primary beneficiary in December 2008 and consolidated, and
- $9 million of higher mark-to-market results primarily in our retail gas operation. We discuss these results in more detail in the *Mark-to-Market* section.

These increases were partially offset by the following:

- $66 million of lower gross margin as a result of fewer customers and unfavorable variable load risk associated with wholesale and retail power primarily due to variances from normal weather and lower demand resulting from the economic downturn and our efforts to reduce risk in the business, and
- $17 million related to lower realization of contracts executed in prior periods and lower volumes in our wholesale and retail power supply operations, partially offset by higher margins on new business originated and realized during 2009.

The $124 million decrease in Customer Supply gross margin in 2008 compared to 2007 is primarily due to the following:

- $112 million of lower gross margin related to unfavorable price movements and lower volumes in our retail power operation,
- $49 million of lower gross margin related to lower realization of contracts executed in prior periods and lower new business originated and realized during the year at our wholesale power operation, and
- $27 million of lower mark-to-market results in our retail gas operation. We discuss this in more detail in the *Mark-to-Market* section.

These decreases were partially offset by approximately $64 million of higher gross margin related to our retail gas operation primarily due to the acquisition of Cornerstone Energy on July 1, 2007.

Global Commodities

We analyze Global Commodities results in the following categories:

- Portfolio Management and Trading—our centralized risk management service related to energy price risk associated with our generation fleet, wholesale and retail customer supply business, and our structured products portfolio.
- Structured Products—customized risk management products in the power, gas, coal and freight markets (e.g., generation tolls, gas transport and storage, and global coal and freight logistics). During 2009, we reduced our participation in the coal, freight and gas trading markets through the divestiture of our international coal and freight and our natural gas trading businesses.
- Energy Investments—investments in energy assets that primarily include natural gas properties and a joint interest in an entity that owns dry bulk cargo vessels. We sold our interest in the entity that owns dry bulk cargo vessels during 2009.

The $30 million decrease in gross margin from our Global Commodities operation during 2009 compared to the same period of 2008 is primarily due to:

- $140 million of lower gross margin from our energy investments operation primarily related to lower business realized on our upstream gas activities within 2009, and
- $139 million of lower gross margin in our structured products portfolio primarily as a result of fewer transactions during 2009.

These decreases were partially offset by an increase of $249 million in our portfolio management and trading operation. These changes are discussed further in the table below.

As previously discussed, the energy markets were affected by substantial volatility in commodity prices during 2008. These market impacts are reflected in the $433 million decrease in gross margin from our Global Commodities operation during 2008 compared to the same period of 2007 primarily due to $698 million of lower gross margin in our portfolio management and trading activities, which are discussed further in the table below. This is partially offset by:

- $208 million from gains in our structured products portfolio, consisting of approximately $135 million as a result of the termination and sale of in-the-money energy purchase contracts, coal supply contracts, and freight contracts to eliminate or reduce operation and performance risk with certain counterparties, and approximately $73 million related to higher realization of contracts executed in prior periods, and
- $57 million in our energy investments operation primarily due to higher realization of contracts executed in prior periods.

Our portfolio management and trading operation gross margin increased $249 million in 2009 compared to 2008 and decreased $698 million in 2008 compared to 2007 primarily due to the following:

	2009 vs. 2008	2008 vs. 2007
	(In millions)	
Change in portfolio management of positions arising from hedges of accrual positions with Generation and Customer Supply activities due to the impact of changes in prices of power, natural gas, and coal	**$ 549**	$(206)
Change in gains recognized on hedges due to ineffectiveness and certain cash-flow hedges that no longer qualified for hedge accounting	**135**	(43)
Change primarily due to write-downs of our emission allowance inventory recorded in 2008 that did not recur at the same level in 2009	**48**	(70)
Change in earnings related to our portfolio of contracts subject to mark-to-market accounting. We discuss these results in more detail in the *Mark-to-Market* section below.	**(455)**	(282)
Decrease due to loss reclassified from accumulated other comprehensive loss to earnings in connection with the closing of the sale of our international commodities operation as a result of hedged transactions that were probable of not occurring by the end of the specified contract period.	**(166)**	—
Discontinuation of cash-flow hedge accounting for derivative contracts within our international commodities operation	**—**	(42)
Increase due to the absence of our international coal and freight operations, which were divested in March 2009, and assignment of certain contracts in 2009	**83**	—
Change due to the absence of a loss as a result of the bankruptcy of one of our domestic coal suppliers. During the first quarter of 2008, as a result of a default by the supplier, we terminated our derivative contracts with the supplier, reclassified the related asset to accounts receivable and fully reserved the amount.	**55**	(55)
Total change in portfolio management and trading gross margin	**$ 249**	$(698)

Mark-to-Market

Mark-to-market results include net gains and losses from origination, risk management, and trading activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section and in *Note 1 to Consolidated Financial Statements*.

The nature of our operations and the use of mark-to-market accounting for certain activities create fluctuations in mark-to-market earnings. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Risk Management* section. The primary factors that cause fluctuations in our mark-to-market results are:

- changes in the level and volatility of forward commodity prices and interest rates,
- counterparty creditworthiness,
- the number and size of our open derivative positions, and
- the number, size, and profitability of new transactions, including termination or restructuring of existing contracts.

During 2009, we focused our activities on reducing capital requirements, reducing long-term economic risk, and reducing short- and interim-term liquidity requirements. These actions may impact the future results of the merchant energy business, particularly the size of and potential for changes in fair value of activities subject to mark-to-market accounting.

The primary components of mark-to-market results are origination gains and gains and losses from risk management and trading activities.

Origination gains arise primarily from contracts that our Global Commodities operation structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction.

Risk management and trading—mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the effects of changes in valuation adjustments. In addition to our fundamental risk management and trading activities, we also use non-trading derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices, while in general the underlying physical transactions related to these activities are accounted for on an accrual basis.

We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset later in this section.

Mark-to-market results were as follows:

	2009	2008	2007
		(In millions)	
Unrealized mark-to-market results			
Origination gains	**$ —**	$ 73.8	$ 41.9
Risk management and trading—mark-to-market			
Unrealized changes in fair value	**(212.3)**	159.8	500.8
Changes in valuation techniques	**—**	—	—
Reclassification of settled contracts to realized	**(265.4)**	48.2	(369.3)
Total risk management and trading—mark-to-market	**(477.7)**	208.0	131.5
Total unrealized mark-to-market*	**(477.7)**	281.8	173.4
Realized mark-to-market	**265.4**	(48.2)	369.3
Total mark-to-market results**	**$(212.3)**	$233.6	$ 542.7

* *Total unrealized mark-to-market is the sum of origination transactions and total risk management and trading—mark-to-market.*

** *Includes gains (losses) on hedge ineffectiveness for fair value hedges recorded in gross margin.*

Total mark-to-market results decreased $445.9 million during the year ended December 31, 2009 compared to the same period of 2008. The period-to-period variance in unrealized changes in fair value was due to decreased unrealized risk management and trading results of $372.1 million and the decrease in origination gains of $73.8 million. We discuss the decrease in origination gains below.

The decrease in risk management and trading results of $372.1 million was primarily due to:

- $203 million of lower results in our domestic coal portfolio primarily as a result of less favorable price movements relating to economic hedges which substantially decreased in value as coal prices decreased in 2009,
- $104 million of lower gains in our international coal and freight operation as a result of its divestiture in March 2009,
- $123 million of lower gains in our wholesale natural gas risk management and trading operation primarily as a result of the divestiture of our natural gas trading operation in the beginning of April 2009, and
- $45 million of lower results related to our emissions trading activities primarily as a result of a less favorable price environment.

These decreases were partially offset by the following:

- $84 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities primarily in the PJM, Northeast, and New York regions as a result of a more favorable price environment in 2009 and our activities to reduce risk and improve liquidity, and
- $19 million of lower losses in our retail gas portfolio primarily due to a more favorable price environment in 2009.

Total mark-to-market results decreased $309.1 million during the year ended December 31, 2008 compared to the same period of 2007 primarily due to unrealized changes in fair value. The period-to-period variance in unrealized changes in fair value was due to lower gains from unrealized changes in fair value of $341.0 million from risk management and trading, partially offset by an increase in origination gains of $31.9 million. We discuss the increase in origination gains below.

The net decrease in risk management and trading gains of $341.0 million was primarily due to:

- $619 million of increased losses primarily related to power and transmission trading activities in the northeast, PJM, and ERCOT regions due to unfavorable price movements, execution of transactions to reduce our risk position consistent with changes in our strategy, and execution of those transactions in less liquid market conditions,
- lower gains of $29 million from our emissions trading activities due primarily to unfavorable price movements, and
- $104 million of increased losses related to unfavorable price movements on certain economic hedges of accrual transactions, primarily related to gas transportation and storage and freight activities that do not qualify for or are not designated as cash-flow hedges.

The risk management and trading results were partially offset by:

- $356 million of gains primarily as a result of favorable price movements relating to economic hedges which substantially increased in value as coal prices decreased in the fourth quarter of 2008. These positions were previously accounted for as cash-flow hedges and were de-designated due to the announced sale of our international commodities operation, and
- $55 million of gains primarily related to our wholesale and retail gas businesses due to favorable price movements on our sales of wholesale and retail natural gas.

We did not record any origination gains during 2009. During 2008, our Global Commodities operation amended certain nonderivative contracts to mitigate counterparty performance risk under the existing contracts. As a result of these amendments, the revised contracts became derivatives subject to mark-to-market accounting. The change in accounting for these contracts from nonderivative to derivative resulted in substantially all of the origination gains for 2008 presented in the unrealized mark-to-market results table above.

During 2007, our Global Commodities operation amended certain nonderivative power sales contracts such that the new contracts became derivatives subject to mark-to-market accounting. Simultaneous with the amending of the nonderivative contracts, we executed at current market prices several new offsetting derivative power purchase contracts subject to mark-to-market accounting. The combination of these transactions resulted in substantially all of the origination gains presented for 2007 in the preceding table, as well as mitigated our risk exposure under the amended contracts.

The origination gains in 2007 from these transactions was partially offset by approximately $12 million of losses in our accrual portfolio due to the reclassification of losses related to cash-flow hedges previously established for the amended nonderivative contracts from "Accumulated other comprehensive loss" into earnings. In the absence of these transactions, the economic value represented by the origination gains and the losses associated with cash-flow hedges would have been recognized over the remaining term of the contracts, which extended through the first quarter of 2009.

The recognition of origination gains is generally dependent on sufficient available market data that validates the initial fair value of the contract. Liquidity and market conditions impact our ability to identify sufficient, objective market price information to permit recognition of origination gains. As a result, the level of origination gains we are able to recognize may vary from year to year as a result of the number, size, and market price transparency of the individual transactions executed in any period.

Derivative Assets and Liabilities

Derivative assets and liabilities consisted of the following:

At December 31,	**2009**	2008
	(In millions)	
Current assets	**$ 639.1**	$ 1,465.0
Noncurrent assets	**633.9**	851.8
Total assets	**1,273.0**	2,316.8
Current liabilities	**632.6**	1,241.8
Noncurrent liabilities	**674.1**	1,115.0
Total liabilities	**1,306.7**	2,356.8
Net derivative position	**$ (33.7)**	$ (40.0)
Composition of net derivative exposure:		
Hedges	**$ (591.0)**	$(1,837.6)
Mark-to-market	**524.3**	1,485.9
Net cash collateral included in derivative balances	**33.0**	311.7
Net derivative position	**$ (33.7)**	$ (40.0)

As discussed in our *Critical Accounting Policies* section, our "Derivative assets and liabilities" include contracts accounted for as hedges and those accounted for on a mark-to-market basis. These amounts are presented in our Consolidated Balance Sheets after the impact of netting, which is discussed in more detail in *Note 1 to Consolidated Financial Statements*. Due to the impacts of commodity prices, the number of open positions, master netting arrangements, and offsetting risk positions on the presentation of our derivative assets and liabilities in our Consolidated Balance Sheets, we believe an evaluation of the net position is the most relevant measure, and is discussed in more detail below. However, we present our gross derivatives in *Note 13 to Consolidated Financial Statements.*

The decrease of $1,246.6 million in our net derivative liability subject to hedge accounting since December 31, 2008 primarily was due to $1,896 million of realization of out-of-the-money cash-flow hedges at the time the forecasted transaction occurred, partially offset by $649 million of increased unrealized losses on our remaining out-of-the-money cash-flow hedge positions primarily related to decreases in power, natural gas, and coal prices during 2009.

The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during 2009 and 2008:

	2009		2008	
		(In millions)		
Fair value beginning of year		**$1,485.9**		$ 673.0
Changes in fair value recorded in earnings				
Origination gains	**$ —**		$ 73.8	
Unrealized changes in fair value	**(212.3)**		159.8	
Changes in valuation techniques	**—**		—	
Reclassification of settled contracts to realized	**(265.4)**		48.2	
Total changes in fair value		**(477.7)**		281.8
Changes in value of exchange-listed futures and options		**97.8**		571.3
Net change in premiums on options		**84.9**		19.2
Contracts acquired		**(35.8)**		—
Dedesignated contracts and other changes in fair value		**(630.8)**		(59.4)
Fair value at end of year		**$ 524.3**		$1,485.9

Changes in our net derivative asset subject to mark-to-market accounting that affected earnings were as follows:

- Origination gains represent the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules.
- Unrealized changes in fair value represent unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.
- Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the economic value of our contracts.
- Reclassification of settled contracts to realized represents the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

The net derivative asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income (Loss):

- Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in nonregulated revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Derivative assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third party broker.
- Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net derivative asset and premiums on options sold as a decrease in the net derivative asset.
- Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Derivative assets and liabilities" in our Consolidated Balance Sheets. Substantially all of this activity for 2009 related to the divestiture of our international commodities operation, Houston-based gas trading operation, and certain other trading operations in order to transfer risk and reward to the buyers.
- Dedesignated contracts and other changes in fair value include transfers of derivative contracts from cash-flow hedges to mark-to-market treatment, transfers of derivative contracts from mark-to-market treatment to cash-flow hedges, and those derivative contracts that did not meet the qualifications of cash flow hedge accounting. During 2009, substantially all of the activity related to dedesignations in connection with the strategic objective of restructuring and reducing the risk of our portfolio.

The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of December 31, 2009:

	Settlement Term							
	2010	2011	2012	2013	2014	2015	Thereafter	Fair Value
	(In millions)							
Level 1	$ 1.6	$ —	$ —	$ —	$ —	$ —	$ —	$ 1.6
Level 2	73.7	636.5	102.1	(18.1)	(2.9)	0.1	1.3	792.7
Level 3	58.6	(197.9)	(140.6)	(12.8)	10.4	9.9	2.4	(270.0)
Total net derivative asset (liability) subject to mark-to-market accounting	$133.9	$ 438.6	$ (38.5)	$(30.9)	$ 7.5	$10.0	$3.7	$ 524.3

Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed. Future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

We manage our mark-to-market risk on a portfolio basis based upon the delivery period of our contracts and the individual components of the risks within each contract. Accordingly, we manage the energy purchase and sale obligations under our contracts in separate components based upon the commodity (e.g., electricity or gas), the product (e.g., electricity for delivery during peak or off-peak hours), the delivery location (e.g., by region), the risk profile (e.g., forward or option), and the delivery period (e.g., by month and year).

The electricity, fuel, and other energy contracts we hold have varying terms to maturity, ranging from contracts for delivery the next hour to contracts with terms of ten years or more. Because an active, liquid electricity futures market comparable to that for other commodities has not developed, many contracts are direct contracts between market participants and are not exchange-traded or financially settling contracts that can be readily offset in their entirety through an exchange or other market mechanism. Consequently, we and other market participants generally realize the value of these contracts as cash flows become due or payable under the terms of the contracts rather than through selling or liquidating the contracts themselves.

In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the preceding table. However, based upon the nature of our Global Commodities operation, we expect to realize the value of these contracts, as well as any contracts we may enter into in the future to manage our risk, over time as the contracts and related hedges settle in accordance with their terms. Generally, we do not expect to realize the value of these contracts and related hedges by selling or assigning the contracts themselves in total.

Operating Expenses

Our merchant energy business operating expenses decreased $195.5 million during 2009 as compared to 2008 due to lower performance-based labor and benefit costs of $95.7 million and lower non-labor operating expenses of $99.8 million, part of which represents the absence of costs from the divestitures completed in 2009 and from deconsolidating CENG on November 6, 2009.

Our merchant energy business operating expenses decreased $62.1 million during 2008 compared to 2007 due to lower performance-based labor and benefit costs at our merchant energy business of $129.2 million, partially offset by higher non-labor operating expenses of $67.1 million, which included approximately $32 million of higher bad debt expense.

For 2010, we expect a further decrease in operating expenses as a result of the deconsolidation of CENG on November 6, 2009. We discuss this impact further in the *Effects of Transaction with EDF on Statement of Income (Loss)* section.

Merger Termination and Strategic Alternatives Costs

We discuss costs related to the terminated merger with MidAmerican, the conversion of our Series A Preferred Stock, our transaction with EDF and our pursuit of other strategic alternatives in *Note 2 to Consolidated Financial Statements*.

Impairment Losses and Other Costs

Our impairment losses and other costs are discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Workforce Reduction Costs

Our merchant energy business recognized expenses associated with our workforce reduction efforts as discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Amortization of Credit Facility Amendment Fees

Our merchant energy business incurred costs related to the amortization of credit facility amendment fees in connection with the EDF transaction. These costs are classified as part of "Other income (expense)" in our Consolidated Statements of Income (Loss).

Depreciation, Depletion and Amortization Expense
Our merchant energy business incurred lower depreciation, depletion and amortization expenses of $36.9 million during 2009 compared to 2008 due to the absence of depletion expenses of $43.1 million as a result of divestitures made in 2008 in our upstream gas operations, partially offset by an increase of $6.2 million in depreciation on our generating facilities.

Merchant energy depreciation, depletion, and amortization expenses increased $17.2 million in 2008 compared to 2007 mostly due to increased depletion expenses related to our upstream natural gas operations as a result of increased drilling and production, partially offset by the cessation of operations at our synfuel facilities in December 2007.

Taxes Other Than Income Taxes
Taxes other than income taxes decreased $15.8 million in 2009 compared to 2008, due to $8.1 million of lower gross receipts taxes at our retail customer supply operation, $5.8 million of lower production taxes related to our upstream gas producing properties, and $1.9 million in lower property, franchise, and other taxes.

Taxes other than income taxes increased $14.1 million in 2008 compared to 2007, due to $9.8 million in higher property and franchise taxes at our Generation operation, $2.9 million of higher gross receipts taxes at our retail customer supply operation, and $1.4 million of higher production taxes related to our upstream gas producing properties.

Gain on Sale of 49.99% Interest in CENG
On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF. As a result of this sale, we recognized a $7.4 billion pre-tax gain. We discuss this transaction in *Note 2 to Consolidated Financial Statements*.

(Loss) Gain on Divestitures
During 2009, we sold a majority of our international commodities operation, our Houston-based gas trading operation, certain other trading operations, and a uranium market participant, and we recognized a pre-tax loss of $464.2 million.

During 2008, we recognized net gains of $25.5 million, including a $14.3 million gain, net of the noncontrolling interest gain of $0.7 million, related to the sale of our working interests in oil and natural gas producing wells in Oklahoma to Constellation Energy Partners that was completed in the first quarter of 2008.

We discuss these divestitures in more detail in *Note 2 to Consolidated Financial Statements.*

Equity Investment (Losses) Earnings
During 2009, our equity investment earnings decreased $63.6 million from 2008 primarily due to $39.1 million of lower earnings from our shipping joint venture as a result of the sale of our interests in July 2009, $16.5 million of lower earnings on investments in power projects, and $12.3 million of lower earnings from our investment in CEP, partially offset by $4.3 million in earnings related to our investment in CENG.

Equity investment earnings increased $74.2 million in 2008 compared to 2007 primarily due to $38.0 million of higher earnings from our shipping joint venture, $34.6 million of higher earnings on investments in power projects, and $1.6 million of higher earnings from our investment in CEP.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business—Electric Business* section.

Results

	2009	2008	2007
		(In millions)	
Revenues	**$ 2,820.7**	$ 2,679.7	$ 2,455.7
Electricity purchased for resale expenses	**(1,840.9)**	(1,880.1)	(1,500.4)
Operations and maintenance expenses	**(399.0)**	(380.5)	(376.1)
Workforce reduction costs	**—**	(4.6)	—
Depreciation and amortization	**(218.1)**	(184.2)	(187.4)
Taxes other than income taxes	**(142.9)**	(139.1)	(140.2)
Income from Operations	**$ 219.8**	$ 91.2	$ 251.6
Net Income	**$ 79.1**	$ 11.1	$ 107.9
Net Income attributable to common stock	**$ 68.9**	$ 1.1	$ 97.9
Other Items Included in Operations (after-tax):			
Residential customer rate credit	**$ (56.7)**	$ —	$ —
Maryland settlement credit	**—**	(110.5)	—
Workforce reduction costs	**—**	(2.8)	—
Total Other Items	**$ (56.7)**	$ (113.3)	$ —

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income attributable to common stock from the regulated electric business increased $67.8 million in 2009 compared to 2008, mostly due to a $53.8 million after-tax decrease in credits provided to customers.

Net income attributable to common stock from the regulated electric business decreased $96.8 million in 2008 compared to 2007, primarily due to the impact of the Maryland settlement credit of $110.5 million after-tax.

Electric Revenues

The changes in electric revenues in 2009 and 2008 compared to the respective prior year were caused by:

	2009 vs. 2008	2008 vs. 2007
	(In millions)	
Distribution volumes	**$ (6.3)**	$ (15.0)
Residential customer rate credit	**(95.0)**	—
Nuclear decommissioning charges	**18.7**	—
Smart Energy Savers Program℠ surcharges	**29.3**	—
Maryland settlement credit	**189.1**	(189.1)
Revenue decoupling	**22.7**	12.5
Standard offer service	**(33.2)**	79.4
Rate stabilization credits	**—**	287.3
Rate stabilization recovery	**(2.7)**	43.1
Financing credits	**3.4**	(9.1)
Senate Bill 1 credits	**6.9**	3.3
Total change in electric revenues from electric system sales	**132.9**	212.4
Other	**8.1**	11.6
Total change in electric revenues	**$141.0**	$ 224.0

Distribution Volumes

Distribution volumes are the amount of electricity that BGE delivers to customers in its service territory.

The percentage changes in our electric system distribution volumes, by type of customer, in 2009 and 2008 compared to the respective prior year were:

	2009	2008
Residential	**(1.3)%**	(2.6)%
Commercial	**—**	(3.6)
Industrial	**(6.7)**	(6.3)

In 2009, we distributed less electricity to residential customers due to decreased usage per customer, partially offset by colder winter weather and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

In 2008, we distributed less electricity to residential and commercial customers due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers before the end of March 2010 totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential electric customers was $95.0 million pre-tax. This credit was accrued in the fourth quarter of 2009 and will be applied to BGE residential electric customer bills in the first quarter of 2010.

Nuclear Decommissioning Charges

Effective January 1, 2009, BGE and Calvert Cliffs Nuclear Power Plant Inc. (Calvert Cliffs) mutually agreed to terminate the decommissioning funds collection agent agreement, which was effective from July 1, 2000 to December 31, 2008. As a result, BGE ceased transferring funds to provide for the decommissioning of Calvert Cliffs Unit 1 and Unit 2. Calvert Cliffs retains the obligation to provide adequate assurances of funding pursuant to Nuclear Regulatory Commission requirements. Under the 2008 Maryland settlement agreement, BGE will continue to provide certain credits to residential customers and assess certain charges to all customers relating to decommissioning.

Smart Energy Savers Program℠ Surcharge

Beginning in 2009, the Maryland PSC approved customer surcharges through which BGE recovers costs associated with certain programs designed to help BGE manage peak demand and encourage customer energy conservation.

Maryland Settlement Credit

As discussed in more detail in *Note 2 to Consolidated Financial Statements*, BGE entered into a settlement agreement with the State of Maryland and other parties, which provided residential electric customers a credit totaling $170 per customer. The estimated settlement of $188.2 million was accrued in the second quarter of 2008 and a total of $189.1 million was credited to customers in the third and fourth quarters of 2008.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier. We discuss the provisions of Maryland's Senate Bill 1 related to residential electric rates in the *Business Environment—Regulation—Maryland—Senate Bills 1 and 400* section.

Standard offer service revenues decreased in 2009 compared to 2008 mostly due to lower standard offer service volumes, partially offset by higher standard offer service rates.

Standard offer service revenues increased in 2008 compared to 2007 mostly due to higher standard offer service rates, partially offset by lower standard offer service volumes.

Rate Stabilization Credits

As a result of Senate Bill 1, we were required to defer from July 1, 2006 until May 31, 2007 a portion of the full market rate increase resulting from the expiration of the residential rate freeze. In addition, we offered a plan also required under Senate Bill 1 allowing residential customers the option to defer the transition to market rates from June 1, 2007 until January 1, 2008.

Revenues in 2008 increased compared to 2007 as a result of the expiration of the rate stabilization plans.

Rate Stabilization Recovery

In late June 2007, BGE began recovering amounts deferred during the first rate deferral period that ended on May 31, 2007. The recovery of the first rate stabilization plan will occur over approximately ten years. In April 2008, BGE began recovering amounts deferred during the second rate deferral period that ended on December 31, 2007. The recovery of the second rate deferral occurred over a 21-month period that began April 1, 2008 and ended on December 31, 2009.

Financing Credits

Concurrent with the recovery of the deferred amounts related to the first rate deferral period, we are providing credits to residential customers to compensate them primarily for income tax benefits associated with the financing of the deferred amounts with rate stabilization bonds.

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of our Calvert Cliffs Nuclear Power Plant and to suspend collection of the residential return component of the administrative charge collected through residential SOS rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of the administrative charge. Under the 2008 Maryland settlement agreement, which is discussed in more detail in *Note 2 to Consolidated Financial Statements*, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers.

The increase in revenues during 2009 compared to 2008 is primarily due to the absence of the credit for the residential return component of the administrative charge which was suspended under the Maryland settlement agreement, partially offset by lower distribution volumes.

The increase in revenues during 2008 compared to 2007 is primarily due to the absence of the credit for the residential return component of the administrative charge which was suspended under the Maryland settlement agreement, partially offset by lower distribution volumes.

Electricity Purchased for Resale Expenses

Electricity purchased for resale expenses include the cost of electricity purchased for resale to our standard offer service customers. These costs do not include the cost of electricity purchased by delivery service only customers. The following table summarizes our regulated electricity purchased for resale expenses:

	2009	2008	2007
		(In millions)	
Actual costs	**$1,781.9**	$1,821.1	$1,759.2
Deferral under rate stabilization plan	**—**	—	(287.3)
Recovery under rate stabilization plans	**59.0**	59.0	28.5
Electricity purchased for resale expenses	**$1,840.9**	$1,880.1	$1,500.4

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $39.2 million for 2009 compared to 2008, primarily due to lower standard offer service volumes, partially offset by higher standard offer service rates.

BGE's actual costs for electricity purchased for resale increased $61.9 million for 2008 compared to 2007, primarily due to higher contract prices to purchase electricity for our customers, partially offset by lower volumes.

Deferral under Rate Stabilization Plan

The deferral of the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under Senate Bill 1 ended on December 31, 2007. In 2007, we deferred $287.3 million in electricity purchased for resale expenses. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Business Environment—Regulation—Maryland—Senate Bills 1 and 400* section.

Recovery under Rate Stabilization Plans

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $59.0 million per year in 2009 and 2008 in deferred electricity purchased for resale expenses. These collections secure the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $18.5 million in 2009 compared to 2008, primarily due to increased uncollectible accounts receivable expense of $5.1 million and the impact of inflation on other costs of $8.0 million.

Regulated electric operations and maintenance expenses increased $4.4 million in 2008 compared to 2007 mostly due to increased uncollectible accounts receivable expense of $14.2 million, partially offset by $9.0 million of lower labor and benefit costs.

Workforce Reduction Costs

During the fourth quarter of 2008, we executed a restructuring of the workforce. We recognized a $4.6 million pre-tax charge in 2008 related to this reduction in force.

We incurred no workforce reduction costs in 2009 or 2007.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense increased $33.9 million during 2009, compared to 2008, primarily due to $43.3 million in increased amortization expense associated with the Smart Energy Savers Program[SM] and additional property placed in service in 2009, partially offset by $18.7 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement.

Regulated electric depreciation and amortization expense decreased $3.2 million in 2008 compared to 2007, primarily due to $10.0 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement. The Maryland settlement agreement is discussed in more detail in *Note 2 to Consolidated Financial Statements*. This decrease was partially offset by additional property placed in service in 2008.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $3.8 million during 2009 compared to 2008, primarily due to the impact of $94.1 million pre-tax in lower customer credits on franchise taxes.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business—Gas Business* section.

Results

	2009	2008	2007
	(In millions)		
Revenues	**$ 758.3**	$1,024.0	$ 962.8
Gas purchased for resale expenses	**(449.9)**	(694.5)	(639.8)
Operations and maintenance expenses	**(160.9)**	(157.3)	(157.5)
Workforce reduction costs	**—**	(1.8)	—
Depreciation and amortization	**(44.0)**	(43.7)	(46.8)
Taxes other than income taxes	**(34.9)**	(35.4)	(36.1)
Income from Operations	**$ 68.6**	$ 91.3	$ 82.6
Net Income	**$ 25.5**	$ 40.4	$ 32.0
Net Income attributable to common stock	**$ 22.5**	$ 37.2	$ 28.8
Other Items Included in Operations (after-tax):			
Residential customer rate credit	**$ (10.4)**	$ —	$ —
Workforce reduction costs	**—**	(1.0)	—
Total Other Items	**$ (10.4)**	$ (1.0)	$ —

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income attributable to common stock from the regulated gas business decreased $14.7 million in 2009 compared to 2008, primarily due to the accrual of a customer rate credit of $10.4 million after-tax and increased operations and maintenance expenses of $2.2 million after-tax.

Net income attributable to common stock from the regulated gas business increased $8.4 million in 2008 compared to 2007, primarily due to an increase in revenues less gas purchased for resale expenses of $4.0 million after-tax and reduced depreciation and amortization expense of $1.9 million after-tax.

Gas Revenues

The changes in gas revenues in 2009 and 2008 compared to the respective prior year were caused by:

	2009 vs. 2008	2008 vs. 2007
	(In millions)	
Distribution volumes	**$ 1.5**	$ (5.1)
Residential customer rate credit	**(17.4)**	—
Conservation surcharge	**1.0**	(0.1)
Revenue decoupling	**(1.8)**	6.2
Gas cost adjustments	**(130.0)**	20.3
Total change in gas revenues from gas system sales	**(146.7)**	21.3
Off-system sales	**(116.6)**	40.3
Other	**(2.4)**	(0.4)
Total change in gas revenues	**$(265.7)**	$61.2

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2009 and 2008 compared to the respective prior year were:

	2009	2008
Residential	0.9%	(3.9)%
Commercial	(10.6)	(3.1)
Industrial	12.5	2.8

In 2009, we distributed more gas to residential customers due to colder winter weather. We distributed less gas to commercial customers due to decreased usage per customer, partially offset by an increased number of customers and colder weather. We distributed more gas to industrial customers mostly due to increased usage per customer, partially offset by a decreased number of customers.

In 2008, we distributed less gas to residential customers and commercial customers due to decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer, partially offset by a decreased number of customers.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential gas customers was $17.4 million pre-tax. This credit was accrued in the fourth quarter of 2009 and will be applied to BGE residential gas customer bills in the first quarter of 2010.

Conservation Surcharge

Beginning February 2009, the Maryland PSC approved a customer surcharge through which BGE recovers costs associated with certain programs designed to help BGE encourage customer conservation.

Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1 to Consolidated Financial Statements*. However, under the market-based rates mechanism approved by the Maryland PSC, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Customers who do not purchase gas from BGE are not subject to the gas cost adjustment clauses because we are not selling gas to them. However, these customers are charged base rates to recover the costs BGE incurs to deliver their gas through our distribution system, and are included in the gas distribution volume revenues.

Gas cost adjustment revenues decreased in 2009 compared to 2008 because we sold less gas at lower prices.

Gas cost adjustment revenues increased in 2008 compared to 2007 because we sold gas at higher prices, partially offset by less gas sold.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Off-system gas sales, which occur after BGE has satisfied its customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders). Changes in off-system sales do not significantly impact earnings.

Revenues from off-system gas sales decreased in 2009 compared to 2008 because we sold less gas at lower prices.

Revenues from off-system gas sales increased in 2008 compared to 2007 because we sold gas at higher prices, partially offset by less gas sold.

Gas Purchased For Resale Expenses

Gas purchased for resale expenses include the cost of gas purchased for resale to our customers and for off-system sales. These costs do not include the cost of gas purchased by delivery service only customers.

Gas costs decreased $244.6 million in 2009 compared to 2008 because we purchased less gas at lower prices.

Gas costs increased $54.7 million in 2008 compared to 2007 because we purchased gas at higher prices, partially offset by lower volumes.

Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses increased $3.6 million during 2009 compared to 2008, primarily due to increased uncollectible accounts receivable expense of $2.0 million.

Gas Workforce Reduction Costs

During the fourth quarter of 2008, we executed a restructuring of the workforce at our operations. We recognized a $1.8 million pre-tax charge in 2008 related to this reduction in force.

We incurred no workforce reduction costs in 2009 or 2007.

Gas Depreciation and Amortization

Regulated gas depreciation and amortization expense decreased $3.1 million in 2008 compared to 2007, primarily due to $3.5 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement. The Maryland settlement agreement is discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Other Nonregulated Businesses

Results

	2009	2008	2007
		(In millions)	
Revenues	**$ 254.6**	$ 259.3	$ 249.8
Operating expenses	**(173.9)**	(178.2)	(173.5)
Impairment losses and other costs	**(26.6)**	—	—
Workforce reduction costs	**—**	(0.4)	—
Depreciation and amortization	**(76.8)**	(68.2)	(53.7)
Taxes other than income taxes	**(4.1)**	(3.0)	(2.4)
Equity (losses) earnings	**(24.8)**	(5.9)	—
Loss on divestitures	**(4.6)**	—	—
(Loss) Income from Operations	**$ (56.2)**	$ 3.6	$ 20.2
Net (Loss) Income	**$ (36.2)**	$ 4.7	$ 16.6
Net (Loss) Income attributable to common stock	**$ (29.0)**	$ 4.7	$ 16.5
Other Items Included In Operations (after-tax):			
Impairment losses and other costs	**$ (11.5)**	$ —	$ —
Loss on divestitures	**(2.9)**	—	—
Workforce reduction costs	**—**	(0.3)	—
Total Other Items	**$ (14.4)**	$ (0.3)	$ —

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net loss attributable to common stock for 2009 exceeded net income attributable to common stock for 2008 by $33.7 million primarily due to increased equity losses from UNE of $11.4 million after-tax, increased impairment losses and other costs due to an impairment of a district chilled water energy plant of $7.1 million after-tax and reduction for noncontrolling interest, a write-off of an uncollectible advance to an affiliate of $4.3 million after-tax, and higher depreciation and amortization expense of $5.2 million after-tax as a result of increased property additions during 2008. UNE will become part of our generation reportable segment in 2010.

Net income attributable to common stock decreased $11.8 million in 2008 compared to 2007 primarily because the first quarter of 2007 included a gain related to a sale of a leasing arrangement that did not occur in 2008 and due to increased depreciation and amortization of $8.7 million after-tax.

Consolidated Nonoperating Income and Expenses

Other (Expense) Income

In 2009, we had other expenses of $140.7 million and, in 2008, we had other expenses of $69.5 million. The $71.2 million increase in 2009 compared to 2008 is mostly due to higher credit facility costs, including amortization of amendment fees.

In 2008, we had other expenses of $69.5 million and, in 2007 we had other income of $157.4 million. The $226.9 million decrease in 2008 compared to 2007 is mostly due to lower interest and investment income of $75 million as a result of a lower average cash balance of approximately $850 million and an increase in other-than-temporary impairment charges related to our nuclear decommissioning trust fund assets of $156.5 million.

Other income at BGE decreased $4.2 million in 2009 compared to 2008 primarily due to decreases in both interest and investment income of $4.2 million.

Other income at BGE increased $2.7 million in 2008 compared to 2007 primarily due to an increase in equity funds capitalized on increased construction work in progress in 2008.

Fixed Charges

Fixed charges increased $56.7 million in 2008 compared to 2007 mostly due to a higher level of interest expense associated with the new debt issuances.

Fixed charges at BGE increased $14.6 million in 2008 compared to 2007 mostly due to a higher level of interest expense associated with the new debt issuances.

Income Taxes

Income tax expense increased $3,065.1 million during 2009 compared to 2008 mostly due to higher income before income taxes due to the recognition of the $7.4 billion pre-tax gain on closing the transaction to sell a 49.99% membership interest in CENG. Additionally, there was lower income before income taxes for 2008, primarily due to approximately $1.2 billion of non-tax deductible merger termination and strategic alternative costs. However, in 2009, certain of these costs became tax deductible as a result of closing the EDF transaction and we recorded a tax benefit for these items in 2009.

BGE's income tax expense increased $43.1 million during 2009, mostly due to higher pre-tax income. For 2008, BGE had a lower effective tax rate as a result of a reduction in its 2008 taxable income due to the impact of certain provisions of the 2008 Maryland settlement agreement, which increased the relative impact of the favorable permanent tax adjustments on its effective tax rate.

Our income tax expense decreased $506.6 million during 2008 compared to 2007 mostly due to a decrease in income before income taxes, which included approximately $1.2 billion of non-tax deductible merger termination and strategic alternatives costs, partially offset by the absence of synthetic fuel tax credits, which expired in 2007.

BGE's income tax expense decreased $75.3 million during 2008 compared to 2007 primarily due to lower pre-tax income as a result of the $189 million Maryland settlement credit recorded in 2008. We discuss the Maryland settlement agreement in more detail in *Note 2 to Consolidated Financial Statements.*

Defined Benefit Plans Funded Status

At December 31, 2009, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $411.7 million. At December 31, 2008, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $936.7 million. The $525.0 million improvement in the funded status of our pension plans in 2009 primarily reflects the following:

- the contribution of $319.4 million into our qualified pension plan trusts during 2009,
- $217.6 million in actual returns on qualified pension plan assets during 2009, and
- the November 6, 2009 separation of CENG pension plans resulting in the net transfer of $176.1 million of projected benefit obligations in excess of the fair value of plan assets.

These increases were partially offset by normal growth in the projected benefit obligations of our qualified and nonqualified pension plans.

At December 31, 2009, our accumulated post retirement benefit obligations totaled $322.3 million compared to $415.4 million at December 31, 2008. The $93.1 million reduction in obligations for these unfunded plans primarily reflects the November 6, 2009 separation of CENG postretirement benefit plans with accumulated post retirement benefit obligations totaling $98.6 million.

Our other postemployment benefit obligation declined $9.3 million from $59.9 million at December 31, 2008 to $50.6 million as of December 31, 2009, primarily due to the deconsolidation of CENG on November 6, 2009.

We discuss our defined benefit plans in further detail in *Note 7 to Consolidated Financial Statements*.

Allowance for Uncollectible Accounts Receivable

Our allowance for uncollectible accounts receivable decreased $80.0 million from $240.6 million at December 31, 2008 to $160.6 million at December 31, 2009, primarily related to a decrease of $93.3 million in our merchant energy business, partially offset by an increase of $13.0 million at our regulated electric and gas businesses.

The decrease in allowance for uncollectible accounts receivable from our merchant energy business is primarily driven by the write-off of the accounts receivable and related allowance for uncollectible accounts receivable balances for certain customers that were established primarily during 2008 when these counterparties encountered financial difficulties. There was no earnings impact associated with these write-offs in 2009.

The increase in allowance for uncollectible accounts receivable from our regulated electric and gas businesses is primarily driven by a Maryland PSC ruling in the second quarter of 2009 and the economic downturn which continues to cause a decreased ability of customers to pay their utility bills. The Maryland PSC ruling in the second quarter of 2009 delayed BGE's ability to terminate service to customers with arrearages and required BGE to offer those customers the option to enter into extended payment plans. BGE ceased entering into these extended plans on September 25, 2009.

If the current economic downturn continues on a prolonged basis, our and BGE's bad debt expense could materially increase in the future despite our efforts to mitigate those risks. We discuss our credit risk in more detail in the *Risk Management* section.

Financial Condition

Balance Sheet Effects of Transaction with EDF

The completion of the sale of a 49.99% membership interest in CENG to EDF on November 6, 2009 had the following significant effects on our Consolidated Balance Sheets:

- received cash proceeds of approximately $3.5 billion,
- increased current and noncurrent unamortized energy contract assets by a total of $0.8 billion,
- increased our accrued taxes by approximately $1.2 billion,
- decreased our long-term debt by approximately $1.0 billion as a result of retiring all of the shares of our Series B Preferred Stock issued to EDF as partial purchase price for their purchase of a 49.99% interest in CENG, and
- increased our retained earnings as a result of recording a $4.5 billion after-tax gain on the transaction.

Additionally, we deconsolidated CENG for financial reporting purposes. The deconsolidation had significant effects on our Consolidated Balance Sheets including the following:

- recorded an initial investment in CENG for approximately $5.2 billion as we treated our retained interest in CENG as an equity investment,
- removed the nuclear decommissioning trust fund assets of approximately $1.2 billion,
- decreased net property, plant and equipment by approximately $3.1 billion,
- decreased our defined benefits by approximately $0.3 billion as a result of the separation of benefit plans, and
- decreased asset retirement obligations by approximately $1 billion.

Cash Flows

The following table summarizes our 2009 cash flows by business segment, as well as our consolidated cash flows for 2009, 2008, and 2007.

	2009 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Holding Company and Other	2009	2008	2007
			(In millions)			
Operating Activities						
Net income (loss)	$ 4,435.0	$ 104.6	$ (36.2)	$ 4,503.4	$(1,318.4)	$ 833.5
Non-cash merger termination and strategic alternatives costs	128.2	—	—	128.2	541.8	—
Derivative contracts classified as financing activities (1)	1,138.3	—	—	1,138.3	(107.2)	32.2
Gain on sale of 49.99% membership interest in CENG	(7,445.6)	—	—	(7,445.6)	—	—
Loss (gain) on divestitures	464.2	—	4.6	468.8	(38.1)	—
Accrual of BGE residential customer credit	—	112.4	—	112.4	—	—
Impairment losses and other costs	98.1	—	26.6	124.7	741.8	20.2
Other non-cash adjustments to net (loss) income	2,071.2	525.0	164.8	2,761.0	602.9	493.0
Changes in working capital						
Derivative assets and liabilities, excluding collateral	419.4	(0.1)	6.0	425.3	(757.9)	(138.2)
Net collateral and margin	1,519.2	3.6	—	1,522.8	(960.3)	49.6
Other changes	803.2	20.9	(57.1)	767.0	93.6	(242.4)
Defined benefit obligations (2)	—	—	—	(287.2)	(20.8)	(53.6)
Other	(44.4)	48.1	168.0	171.7	(38.5)	(53.3)
Net cash provided by (used in) operating activities	3,586.8	814.5	276.7	4,390.8	(1,261.1)	941.0
Investing Activities						
Investments in property, plant and equipment	(1,118.7)	(372.4)	(38.6)	(1,529.7)	(1,934.1)	(1,295.7)
Asset acquisitions and business combinations, net of cash acquired	—	—	(41.1)	(41.1)	(315.3)	(347.5)
Contributions to nuclear decommissioning trust funds	(18.7)	—	—	(18.7)	(18.7)	(8.8)
Investments in joint ventures	(110.0)	—	(91.6)	(201.6)	—	—
Issuances of loans receivable	—	—	—	—	—	(19.0)
Proceeds from sale of 49.99% membership interest in CENG	3,528.7	—	—	3,528.7	—	—
Proceeds from sale of investments and other assets	50.0	—	38.3	88.3	446.3	13.9
Contract and portfolio acquisitions	(2,153.7)	—	—	(2,153.7)	—	(474.2)
(Increase) decrease in restricted funds (3)	(0.2)	(0.6)	1,004.1	1,003.3	(942.8)	(109.9)
Other investments	0.3	—	(0.2)	0.1	21.7	(45.3)
Net cash provided by (used in) investing activities	177.7	(373.0)	870.9	675.6	(2,742.9)	(2,286.5)
Cash flows from operating activities plus cash flows from investing activities	$ 3,764.5	$ 441.5	$1,147.6	5,066.4	(4,004.0)	(1,345.5)
Financing Activities (2)						
Net (repayment) issuance of debt				(2,660.4)	3,447.7	(33.1)
Debt and credit facility costs				(98.4)	(104.8)	—
Proceeds from issuance of common stock				33.9	17.6	65.1
Common stock dividends paid				(228.0)	(336.3)	(306.0)
BGE preference stock dividends paid				(13.2)	(13.2)	(13.2)
Reacquisition of common stock				—	(16.2)	(409.5)
Proceeds from contract and portfolio acquisitions				2,263.1	—	847.8
Derivative contracts classified as financing activities (1)				(1,138.3)	107.2	(32.2)
Other				12.7	8.3	33.4
Net cash (used in) provided by financing activities				(1,828.6)	3,110.3	152.3
Net increase (decrease) in cash and cash equivalents				$ 3,237.8	$ (893.7)	$(1,193.2)

(1) *All ongoing cash flows from derivative contracts deemed to contain a financing element at inception must be reclassified from operating activities to financing activities.*

(2) *Items are not allocated to the business segments because they are managed for the company as a whole.*

(3) *The (increase) decrease in restricted funds at our Holding Company and Other is primarily related to $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF. These funds were held at the holding company and were restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.*

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Cash Flows from Operating Activities

Cash provided by operating activities was $4.4 billion in 2009 compared to cash used in operating activities of $1.3 billion in 2008. This $5.7 billion increase in cash flows was primarily due to:

- $1.2 billion as a result of ongoing cash outflows from derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities. We discuss the impact on cash flows from financing activities below.
- $1.2 billion related to changes in net derivative assets and liabilities. Changes in derivative assets and liabilities are driven by fluctuations in commodity prices and the realization of contracts at settlement within our merchant energy business.
- $0.5 billion of improved operating cash flows from our regulated businesses.
- $2.5 billion more in net collateral and margin returned in 2009 as compared to 2008 as follows:

	December 31, 2009	December 31, 2008
	(In millions)	
Net collateral and margin posted, beginning of year	$(1,445.6)	$ (485.3)
Return of collateral held associated with nonderivative contracts	(17.0)	(26.3)
Net return of (additional) collateral posted associated with nonderivative contracts	336.3	(330.5)
Return of (additional) initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	924.8	(94.0)
Return of (additional) fair value net cash collateral posted (netted against derivative assets/liabilities)*	278.7	(509.5)
Change in net collateral and margin posted	1,522.8	(960.3)
Net collateral and margin held, end of year	$ 77.2	$(1,445.6)

* *We discuss our netting of fair value collateral with our derivative assets/liabilities in more detail in Note 13 to Consolidated Financial Statements.*

The $1.5 billion decrease in net collateral and margin posted during 2009 primarily reflects the following:

- collateral returned/reduced as part of the divestiture of a majority of our international commodities operation and gas trading operation as well as the execution of a gas supply agreement with the buyer of the gas trading operation for the retail gas business,
- fewer contracts as a result of reducing the risk in our portfolio,
- the termination of in-the-money contracts, and
- changes in commodity prices and the level of our open positions.

Cash used in operating activities was $1.3 billion in 2008 compared to cash provided by operating activities of $0.9 billion in 2007. This $2.2 billion decrease in cash flows was primarily due to:

- a $1.0 billion increase in net collateral and margin posted,
- $0.7 billion use of cash, consisting of $0.2 billion paid to MidAmerican related to the termination of the merger, $0.4 billion paid to MidAmerican for settling a portion of the conversion of the Series A Preferred Stock in cash, and $0.1 billion paid to various parties for merger and other strategic alternatives costs,
- $0.2 billion of credits rebated to residential electric customers by BGE as a result of the Maryland settlement agreement, and
- $0.1 billion of additional interest paid.

Cash Flows from Investing Activities

Cash provided by investing activities was $0.7 billion in 2009 compared to cash used of $2.7 billion in 2008. The $3.4 billion increase in cash provided in 2009 compared to 2008 was primarily due to:

- $3.5 billion of net proceeds at the closing the sale of a 49.99% membership interest in CENG to EDF. We discuss this transaction in more detail in *Note 2 to the Consolidated Financial Statements*. There was no such activity in 2008,
- $1.9 billion decrease in restricted funds, primarily due to the receipt of funds in 2008 and the release of funds in 2009 for the repayment of the $1 billion of 14% Senior Notes to MidAmerican in January 2009, and
- $0.3 billion decrease in cash used for acquisitions. In 2009, $20.8 million was used for the acquisition of CLT Efficient Technologies Group, an energy services company that provides energy performance contracting and energy efficiency engineering services, and $20.3 million was used as a down payment for the pending acquisition of the Criterion wind project in Garrett County, Maryland. In 2008, $0.3 billion was used for the acquisition of the Hillabee Energy Center, a partially completed 740 MW gas-fired combined cycle power generation facility in Alabama; the West Valley Power Plant, a 200 MW gas-fired peaking plant; and a uranium market participant.

This increase was partially offset by:

- $2.2 billion of cash used for contract and portfolio acquisitions as a component of our strategic divestitures. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present investing cash flows for in-the-money contracts on a gross basis separate from financing cash inflows for out-of-the-money contracts executed simultaneously. We discuss our divestitures in more detail in *Note 2* to the *Notes to Consolidated Financial Statements*. There was no such activity in 2008.

- $0.2 billion of cash used for a working capital investment in CENG of $0.1 billion and a contribution to UNE of $0.1 billion.

Cash used in investing activities was $2.7 billion in 2008 compared to $2.3 billion in 2007. The $0.4 billion increase in cash used in 2008 compared to 2007 was primarily due to:

- the increase in restricted cash of $0.8 billion, primarily relating to the $1 billion proceeds received from the issuance of Series B Preferred Stock to EDF that is restricted to pay the 14% Senior Notes. The proceeds from the Series B Preferred Stock issuance, as discussed in the cash flows from financing section below, are the source of the funds for the increase in restricted cash. The 14% Senior Notes were subsequently paid in January 2009.
- the increase in investments in property, plant and equipment of $0.6 billion. This increase was primarily driven by environmental spending of $0.5 billion for our Brandon Shores coal-fired generating plant and $48 million in construction costs at our partially completed gas-fired combined cycle power generating facility in Alabama.

These increased uses of cash in investing activities are partially offset by the absence in 2008 of $0.5 billion of cash used in 2007 for contract and portfolio acquisitions, which we discuss in more detail below, and approximately $0.4 billion of higher proceeds received from sales of investments in 2008 compared to 2007. The proceeds in 2008 include $150 million of cash received from EDF that was recorded as additional proceeds for EDF's purchase of 49.99% membership interest in CENG in 2009.

Cash Flows from Financing Activities

Cash used in financing activities was $1.8 billion in 2009 compared to cash provided of $3.1 billion in 2008. The increase in cash used for financing activities of $4.9 billion was primarily due to:

- $3.0 billion net increase in cash used to repay short-term borrowings and long-term debt primarily due to the repayment of the $1 billion 14% Senior Notes to MidAmerican in January 2009, $1.6 billion in net repayments of short-term credit facilities, $0.5 billion repayment of a 6.125% fixed rate note, and a $0.3 billion repayment of Zero Coupon Senior Notes,
- $3.1 billion net decrease in cash received from the issuance of long-term debt, and
- $1.2 billion in cash outflows related to derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities. These contracts primarily relate to transactions associated with the divestiture of our international commodities operation, Houston-based gas trading operation and certain other trading operations. During 2009, we executed derivatives as part of these divestiture transactions at prices that differed from then-current market prices. As a result, cash flows associated with the out-of-the money derivative transactions are deemed to contain a financing element, and we must record the ongoing cash flows related to these contracts as financing cash flows. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements.*

This increase in cash used for financing activities was partially offset by $2.3 billion of cash provided from contract and portfolio acquisitions as a component of our strategic divestitures. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present financing cash inflows for out-of-the-money contracts on a gross basis separate from investing cash outflows for in-the-money contracts executed simultaneously. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements.* There was no such activity in 2008.

Cash provided by financing activities was $3.1 billion in 2008 compared to $0.2 billion in 2007. The increase of $2.9 billion was primarily due to the issuance of:

- $1 billion of mandatorily redeemable Series B Preferred Stock to EDF, the proceeds of which are reflected in the increase in restricted cash, as discussed in the cash flows from investing activities above,
- $1 billion of mandatorily redeemable convertible Series A Preferred Stock to MidAmerican, which was converted, in part, in December 2008 into $1 billion of 14% Senior Notes, which were repaid in full in January 2009,
- $250.0 million of Zero Coupon Notes,
- $450.0 million of 8.625% Series A Junior Subordinated Debentures, and
- $400.0 million of 6.125% Notes by BGE.

Contract and Portfolio Acquisitions

During 2009 and 2007, our merchant energy business acquired several pre-existing energy purchase and sale agreements, which generated significant cash flows at the inception of the contracts. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contract. We received net cash of $109.4 million in 2009 due to the execution of total return swaps to assist in the execution of our divestitures of our international commodities and Houston-based gas trading operations and $373.6 million in 2007 for various contract and portfolio acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year ended December 31,	**2009**	2008	2007
	(In millions)		
Financing activities—proceeds from contract and portfolio acquisitions	**$ 2,263.1**	$—	$ 847.8
Investing activities—contract and portfolio acquisitions	**(2,153.7)**	—	(474.2)
Cash flows from contract and portfolio acquisitions	**$ 109.4**	$—	$ 373.6

We record the proceeds we receive to acquire energy purchase and sale agreements as a financing cash inflow because it constitutes a prepayment for a portion of the market price of energy, which we will buy or sell over the term of the agreements and does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract with the counterparties as financing cash inflows. For those acquired contracts that are not derivatives, we record the ongoing cash flows related to the contract as operating cash flows.

We discuss certain of these contract and portfolio acquisitions in more detail in *Note 2 to Consolidated Financial Statements.*

Cash Flow Impacts—CENG Joint Venture

Prior to November 6, 2009, we recorded 100% of the revenues, expenses, and cash flows from CENG and the nuclear plants it owns because we wholly owned this entity. On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, for the period from November 6, 2009 through December 31, 2009, we ceased recording CENG's cash flows and began to record cash flows from our PPA and other transactions with CENG. In the future, we will record cash flows from any distributions received from CENG based on our 50.01% ownership interest, and we may be required to make capital contributions to help fund CENG's capital program.

As a result of deconsolidation, we expect that our future merchant energy cash flows will differ from historical cash flows primarily due to the following factors:

- We will sell between 85-90% of the output of CENG's plants, excluding output sold by CENG directly to third parties, rather than 100% of the plants' total output including volumes contracted to third parties.
- Fuel and purchased energy expenses will reflect our purchase of 85-90% of the output of CENG's plants, excluding output sold directly to third parties, as provided under the terms of the PPA with CENG.
- Operating expenses will no longer include CENG's plant operating costs or general and administrative expenses.
- We will no longer incur cash flows for 100% of CENG's capital expenditures or the acquisition of nuclear fuel, but we may be required to make capital contributions to help CENG fund these expenditures.
- We will record cash distributions from CENG if and when such distributions are declared.

In addition, we entered into a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and will recognize average annual revenue of approximately $16 million.

The ASA is a one year agreement that is renewable annually under which we will provide administrative support services to CENG for a fee of approximately $66 million for 2010. The level of fees for administrative support services will be subject to change in future years based on the level of services provided. The charges under these agreements are intended to represent the actual cost of the services provided to CENG from us.

Security Ratings

Independent credit rating agencies rate Constellation Energy's and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities and, in certain cases, the company's ability to access the markets to sell securities. Generally, the better the rating, the lower the cost of the securities to each company when they sell them. A reduction in our credit ratings could have an adverse effect on our access to liquidity sources, increase our cost of funds, trigger additional collateral requirements, and/or decrease the number of investors and counterparties willing to transact with us.

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, stock price volatility, political, legislative and regulatory risk, interest charges relative to operating cash flow, and the level of debt relative to operating cash flows and to total capitalization.

At the date of this report, our credit ratings were as follows:

	Standard & Poors Rating Group	Moody's Investors Service	Fitch Ratings
Constellation Energy			
Senior Unsecured Debt	BBB-	Baa3	BBB-
Commercial Paper	A-3	P-3	F3
Junior Subordinated Debentures	BB	Ba1	BB**
BGE			
Senior Unsecured Debt	BBB+	Baa2	BBB+
Commercial Paper	A-2	P-2	F2
Rate Stabilization Bonds*	AAA	Aaa	AAA
Trust Preferred Securities	BBB-	Baa3	BBB-**
Preference Stock	BBB-	Ba1	BBB-**

* *Bonds issued by RSB BondCo LLC, a subsidiary of BGE*

** *As a result of changes in guidelines at Fitch Ratings affecting all issuers, in January 2010 the ratings of our Junior Subordinated Debentures and BGE's Trust Preferred Securities and Preference Stock were downgraded one level.*

All Constellation Energy and BGE ratings in the above table reflect stable outlooks by all the credit rating agencies.

As a condition to the October 2009 Maryland PSC order approving our transaction with EDF, Constellation Energy and BGE were required to implement "ring fencing" measures to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. We completed the implementation of these measures in February 2010.

We remain committed to maintaining a stable investment grade credit profile and to meeting our liquidity requirements. We discuss our available sources of funding in more detail below.

We discuss the potential effect of a ratings downgrade in the *Collateral* section.

Available Sources of Funding

In addition to cash generated from operations, we rely upon access to capital for our capital expenditure programs and for the liquidity required to operate and support our commercial businesses. Our liquidity requirements are funded by credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, many of which support direct cash borrowings and the issuance of commercial paper. We also use our credit facilities to support the issuance of letters of credit, primarily for our merchant energy business.

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our Customer Supply business in both power and gas. As part of our strategic initiatives, we have modified the structure of certain transactions and terminated others in order to reduce these collateral requirements. Significant changes in the prices of commodities, depending on hedging strategies we have employed, could require us to post additional letters of credit, and thereby reduce the overall amount available under our credit facilities or to post additional cash, and thereby reduce our available cash balance.

We discuss our, and BGE's, credit facilities in detail in *Note 8 to the Consolidated Financial Statements*.

Net Available Liquidity

The following tables provide a summary of our net available liquidity at December 31, 2009 and 2008.

As of December 31, 2009	Constellation Energy	BGE	Total Consolidated
		(In billions)	
Credit facilities (1)	$ 3.5	$0.6	$ 4.1
Less: Letters of credit issued	(1.7)	—	(1.7)
Less: Cash drawn on credit facilities	—	—	—
Undrawn facilities	1.8	0.6	2.4
Less: Commercial paper outstanding	—	—	—
Net available facilities	1.8	0.6	2.4
Add: Cash	3.4	—	3.4
Less: Reserved cash (2)	(1.3)	—	(1.3)
Cash and facility liquidity	3.9	0.6	4.5
Add: EDF put arrangement	1.1	—	1.1
Net available liquidity	$ 5.0	$0.6	$ 5.6

(1) *Excludes $0.5 billion commodity-linked credit facility due to its contingent nature. We discuss this credit facility in more detail in Note 8 to Consolidated Financial Statements.*

(2) *Represents management's expectation of income tax payments to be made for the EDF transaction and remaining bond repurchases in the first quarter of 2010. We discuss our bond repurchases in more detail in Note 9 to Consolidated Financial Statements.*

As of December 31, 2008	Constellation Energy	BGE	Total Consolidated
		(In billions)	
Credit facilities	$ 6.2	$ 0.4	$ 6.6
Less: Letters of credit issued	(3.6)	—	(3.6)
Less: Cash drawn on credit facilities	(0.5)	(0.4)	(0.9)
Undrawn facilities	2.1	—	2.1
Less: Commercial paper outstanding	—	—	—
Net available facilities	2.1	—	2.1
Add: Cash	0.2	—	0.2
Net available liquidity	$ 2.3	$ —	$ 2.3

During 2009, net available liquidity increased $3.3 billion due to the following:

	(In billions)	
Expiration of EDF interim backstop liquidity facility	$(0.6)	
Credit facility reductions triggered by completion of CENG joint venture (1)	(3.3)	
New credit facilities added	1.4	
Net reduction in credit facilities		$(2.5)
Decrease in letters of credit issued		1.9
Repayment of cash drawn on facilities		0.9
Increase in cash		3.2
Less: cash reserved for tax payments and debt reductions		(1.3)
EDF put arrangement, after-tax		1.1
Increase in net available liquidity		$ 3.3

(1) *Includes $1.23 billion facility that was set to expire in November 2009.*

Through our efforts to reduce risk and more actively manage our liquidity, we significantly improved our net available liquidity during 2009. Specifically, we executed on our planned divestitures, significantly reduced the activities of our Global Commodities operation, and restructured and terminated existing transactions and amended certain agreements, all of which have led to lower collateral requirements. Through December 31, 2009, we received substantially all of the $1 billion of total net collateral expected to be returned upon the completion of our divestitures. In addition, we added new credit facilities during 2009 that are discussed in more detail in *Note 8 to Consolidated Financial Statements.*

During 2009, our cash balance increased $3.2 billion. The increase is largely a result of the proceeds from the EDF transaction and strong cash flows in our core businesses, partially offset by bond repayments and the retirement of debt prior to maturity. We discuss our cash flows in more detail earlier in the *Cash Flows* section and the EDF transaction in the *Significant Events* section. We intend to use the funds from the EDF transaction to pay the taxes owed on the transaction, to fulfill our $1.0 billion voluntary debt reduction commitment, to fund strategic growth initiatives, and for other general corporate purposes. We discuss our voluntary debt reduction in more detail in *Note 9 to Consolidated Financial Statements.*

In connection with its approval of the EDF transaction, we were required by the Maryland PSC to implement "ring fencing" measures designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. We discuss the Maryland PSC order in more detail in the *Regulation-Maryland* section. These ring fencing measures were implemented in 2010, and as a result BGE no longer participates in the Constellation Energy cash pool.

In December 2009, Constellation Energy contributed approximately $316 million of equity ($250.0 million capital contribution and $65.9 million for a residential customer rate credit) to BGE as required by the Maryland PSC order approving the EDF transaction. As a result of BGE terminating participation in the Constellation Energy cash pool, this equity contribution will be reflected in the cash balance of BGE beginning in January 2010.

Our liquidity needs vary as commodity prices change. We regularly evaluate the effects of changing price levels on our liquidity needs by estimating the impacts of volatile power, gas, and coal prices on our price sensitive sources and uses of liquidity. For example, energy contracts settling in the current year may impact our cash flows and changing price levels may impact our collateral requirements. Additionally, we consider the impact of other sources and uses of liquidity, including planned business divestitures, anticipated new business, capital expenditures, operating expenses and credit charges.

We believe that the actions that we have taken and our current net available liquidity will be sufficient to support our ongoing liquidity requirements. Our liquidity projections include assumptions for commodity price changes, which are subject to significant volatility, and we are exposed to certain operational risks that could have a significant impact on our liquidity. We discuss items that could negatively impact our liquidity in the *Item 1A. Risk Factors* section.

Collateral

Constellation Energy's collateral requirements generally arise from its merchant energy business' need to participate in certain organized markets, such as Independent System Operators (ISOs) or financial exchanges, as well as from our margining on over-the-counter (OTC) contracts.

To support wholesale and retail power Customer Supply obligations and our limited trading activities, Constellation Energy posts collateral to ISOs. Forward hedging of our Generation and Customer Supply obligations, as well as our Global Commodities trading activities, creates the need to transact with exchanges such as New York Mercantile Exchange and Intercontinental Exchange. We post initial margin based on exchange rules, as well as variation margin related to the change in value of the net open position with the exchange. Constellation Energy's initial margin requirements increased during the third quarter of 2008 as a result of changes in exchange rules and decreased during the fourth quarter of 2008 as a result of portfolio risk reduction and downsizing activities.

During 2009, our initial margin requirements continued to decrease. In March 2009 and April 2009, we closed-out our exchange positions related to our international commodities operation and Houston-based gas trading operation, respectively, which reduced our margin posted with each exchange with which we transact.

In addition to the collateral posted to ISOs and exchanges, we post collateral with certain OTC counterparties. These collateral amounts may be fixed or may vary with price levels.

There are certain inherent asymmetries relating to the use of collateral that create liquidity requirements for our merchant energy businesses. These asymmetries arise from our actions to be economically hedged, as well as market conditions or conventions for conducting business that result in some transactions being collateralized while others are not, including:

- In our Customer Supply operation, we generally do not receive collateral under contractual obligations to supply power or gas to our customers but our Global Commodities operation hedges these transactions through purchases of power and gas that generally require us to post collateral. By entering into a gas supply agreement with the buyer of our gas trading operation, we have reduced our collateral requirements to support our retail gas operation. We discuss this gas supply agreement in more detail in *Note 4* of the *Notes to Consolidated Financial Statements*. We also intend to further align our load obligations by buying generation assets in regions where we do not have a significant generation presence and entering into longer-tenor agreements with merchant generators, further reducing our dependence on exchange-traded products, thereby lowering our collateral requirements.
- In our Generation operation, we may have to post collateral on our power sale or fuel purchase contracts.

Finally, collateral types may asymmetrically impact our liquidity. For example, in margining with over-the-counter counterparties, we may post letter of credit (LC) collateral for an out-of-the money counterparty. However, we may receive LC collateral when we are in-the-money with a counterparty. Posting LCs reduces our liquidity while the receipt of LC collateral does not increase our liquidity.

Customers of our merchant energy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at December 31, 2009, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to (1)	Level Below Current Rating	Additional Obligations (2)
	(In billions)	
Below investment grade	1	$1.1

(1) *If there are split ratings among the independent credit-rating agencies, the lowest credit rating is used to determine our incremental collateral obligations.*

(2) *Includes $0.2 billion related to derivative contracts as discussed in Note 13 to Consolidated Financial Statements.*

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post additional collateral in an amount that could exceed the obligation amounts specified above, which could be material. We discuss our credit facilities in the *Available Sources of Funding* section.

Capital Resources

Our actual consolidated capital requirements for the years 2007 through 2009, along with the estimated annual amount for 2010, are shown in the following table.

We will continue to have cash requirements for:

- working capital needs,
- payments of interest, distributions, and dividends,
- capital expenditures, and
- the retirement of debt.

Capital requirements for 2010 and 2011 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of market conditions on those projects,
- the cost and availability of capital,
- potential capital contributions to CENG and UNE,
- the availability of cash from operations, and
- business decisions to invest in capital projects.

Our estimates are also subject to additional factors.

Please see the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

	2007	**2008**	**2009**	**2010 (Estimate)**
		(In billions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Generation plants (1)	$0.2	$0.6	$0.4	$0.2
Environmental controls	0.2	0.5	0.3	0.1
Portfolio acquisitions/ investments	0.5	0.2	0.1	0.1
Technology/other	0.2	0.1	0.1	—
Nuclear fuel (1)	0.1	0.2	0.2	—
Total merchant energy capital requirements	1.2	1.6	1.1	0.4
Other nonregulated capital requirements	0.1	0.1	0.1	0.1
Total nonregulated capital requirements	1.3	1.7	1.2	0.5
Regulated Capital Requirements:				
Regulated electric	0.3	0.4	0.3	0.5
Regulated gas	0.1	0.1	0.1	0.1
Total regulated capital requirements	0.4	0.5	0.4	0.6
Total capital requirements	$1.7	$2.2	$1.6	$1.1

(1) *Reflects the closing of the transaction with EDF on November 6, 2009 and the deconsolidation of our nuclear generation and operation business. As a result, the table above includes ten months of nuclear plant related and nuclear fuel capital requirements for 2009 and none effective in 2010.*

As of the date of this report, we estimate our 2011 capital requirements will be approximately $1.0 billion.

Capital Requirements

Merchant Energy Business

Our merchant energy business' capital requirements consist of its continuing requirements, including expenditures for:

- improvements to generating plants,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

In addition, in December 2009, we were selected by the State of Maryland to construct, own, operate and maintain a 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. We expect this project to cost us approximately $60 million and be completed by December 2012. Renewable electricity produced by the system will be purchased by the State of Maryland at the site of Mount St. Mary's University under a 20-year solar power purchase agreement.

In 2009, we signed an agreement to acquire the 70 MW Criterion wind project in Garrett County, Maryland. The completed cost of this project is expected to be approximately $140 million. We expect to close this transaction, subject to certain conditions, in the first quarter of 2010 and expect commercial operation of the facility in the fall of 2010.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability and support demand response and conservation initiatives.

In July 2009, BGE filed with the Maryland PSC a proposal for a comprehensive smart grid initiative. The proposal includes the planned installation of 2 million residential and commercial electric and gas smart meters. We expect the total cost of the program to be approximately $480 million. In October 2009, the United States Department of Energy selected BGE as a recipient of $200 million in federal funding for our smart grid initiative. This grant allows BGE to be reimbursed for smart grid expenditures up to $200 million, substantially reducing the total cost of this initiative. However, the United States Department of Energy may withhold funding until approval is obtained from the Maryland PSC. The Maryland PSC held hearings on this proposed program in late 2009 and expects to issue an order in the first quarter of 2010. If BGE's proposal is approved by the Maryland PSC, BGE plans to proceed with this program as soon as practical.

Funding for Capital Requirements

Merchant Energy Business

We expect to fund the capital requirements of our merchant energy business with internally generated cash and other available sources. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the money markets, capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities.

The projects that our merchant energy business develops typically require substantial capital investment. Many of the qualifying facilities and independent power projects that we have an interest in as well as our upstream properties are financed primarily with non-recourse debt that is repaid from the project's cash flows. This debt is collateralized by interests in the physical assets, major project contracts and agreements, cash accounts and, in some cases, the ownership interest in that project.

Regulated Electric and Gas

We expect to fund capital expenditures associated with our regulated electric and gas businesses through a combination of internally and externally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the short-term and long-term capital markets (including trust preferred securities or preference stock), subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities. BGE may also receive equity contributions from time to time from Constellation Energy. In December 2009, BGE received a $250 million capital contribution from Constellation Energy as required by the October 2009 order from the Maryland PSC approving our transaction with EDF. At that time, Constellation Energy also funded the after-tax cost of $66 million of the residential customer credits required by the same order.

Other Nonregulated Businesses

We expect to fund the capital requirements of our other nonregulated businesses with internally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the short-term and long-term capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from drawdowns on credit facilities. We may also consider sales of securities and assets, and/or from time to time equity contributions from Constellation Energy.

Contractual Payment Obligations and Committed Amounts

We enter into various agreements that result in contractual payment obligations in connection with our business activities. These obligations primarily relate to our financing arrangements (such as long-term debt, preference stock, and operating leases), purchases of capacity and energy to support the growth in our merchant energy business activities, and purchases of fuel and transportation to satisfy the fuel requirements of our power generating facilities.

We detail our contractual payment obligations as of December 31, 2009 in the following table:

	Payments				
	2010	2011-2012	2013-2014	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt: (1)					
Nonregulated					
Principal	$ 0.4	$ 751.4	$ 20.0	$ 1,903.0	$ 2,674.8
Interest	152.1	299.6	241.9	2,904.3	3,597.9
Total	152.5	1,051.0	261.9	4,807.3	6,272.7
BGE					
Principal	56.5	254.2	537.0	1,352.4	2,200.1
Interest	130.5	247.2	194.9	1,253.4	1,826.0
Total	187.0	501.4	731.9	2,605.8	4,026.1
BGE preference stock	—	—	—	190.0	190.0
Operating leases (2)					
Operating leases, gross	226.0	435.1	375.0	396.4	1,432.5
Sublease rentals	(56.5)	(102.1)	(56.3)	(114.8)	(329.7)
Operating leases, net	169.5	333.0	318.7	281.6	1,102.8
Purchase obligations: (3)					
Purchased capacity and energy (4)	160.9	303.5	107.7	208.7	780.8
Purchased energy from CENG	534.7	1,513.3	2,249.8	—	4,297.8
Fuel and transportation	540.5	437.5	94.3	217.9	1,290.2
Other	77.9	39.3	6.6	6.7	130.5
Other noncurrent liabilities:					
Uncertain tax positions liability	—	143.8	67.7	18.3	229.8
Pension benefits (5)	45.8	217.5	203.7	—	467.0
Postretirement and post employment benefits (6)	32.3	72.9	82.8	185.0	373.0
Total contractual payment obligations	$1,901.1	$4,613.2	$4,125.1	$ 8,521.3	$19,160.7

(1) Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $207 million early through remarketing features. Interest on variable rate debt is included based on forward curve for interest rates.

(2) Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11 to Consolidated Financial Statements.

(3) Contracts to purchase goods or services that specify all significant terms. Amounts related to certain purchase obligations are based on future purchase expectations which may differ from actual purchases.

(4) Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements.

(5) Amounts related to pension benefits reflect our current 5-year forecast for contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 to Consolidated Financial Statements for more detail on our pension plans.

(6) Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded in our Consolidated Balance Sheets as discussed in Note 7 to Consolidated Financial Statements.

Off-Balance Sheet Arrangements

For financing and other business purposes, we utilize certain off-balance sheet arrangements that are not reflected in our Consolidated Balance Sheets. Such arrangements do not represent a significant part of our activities or a significant ongoing source of financing.

We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2009, we have no material off-balance sheet arrangements, including:

- guarantees with third parties that are subject to initial recognition and measurement requirements,
- retained interests in assets transferred to unconsolidated entities or similar arrangement that serves as credit, liquidity or market risk support to such entity for such asset,
- derivative instruments indexed to our common stock, and classified as equity, or
- variable interests in unconsolidated entities that provide financing, liquidity, market risk, or credit risk support, or engage in leasing, hedging or research and development services.

At December 31, 2009, Constellation Energy had a total face amount of $10.4 billion in guarantees outstanding, of which $9.4 billion related to our merchant energy business. These amounts generally do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $2 billion at December 31, 2009, which represents the total amount the parent company could be required to fund based on December 31, 2009 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in *Note 12 to Consolidated Financial Statements* and our significant variable interests in *Note 4 to Consolidated Financial Statements*.

Risk Management

Introduction

Constellation Energy is exposed to market, credit, operational, and business risks that are fundamental to our business of providing products and services across the energy value chain.

In general, the risks in our businesses can be classified as one of the following:

- Market Risk—risk related to changes in energy commodity prices, volatilities, market price correlations, interest rates, and currencies as well as volume uncertainty, load requirements, physical location and supply, and market rules,
- Credit Risk—risk related to a customer's or supplier's inability to fulfill its contractual obligations due to financial distress,
- Operational Risk—risk associated with human error or a failure of process and systems, or external factors, as well as the risk of operating owned and contractually-controlled generating assets, and electric transmission and gas transportation systems,
- Business Risk—risk of unsuccessful business performance due to changing economic conditions, competition, regulatory environment, legislation, and economic conditions, and
- Funding Liquidity Risk—risk that we may be unable to fund our obligations in some future period.

These risks exist in our business with varying levels of exposure, and are interrelated and cannot be managed in isolation.

Each of the five risk classifications noted above can be affected by numerous internal and external forces, including:

- economic conditions,
- market liquidity,
- competition,
- country or sovereign issues,
- systems or process failure, and
- fiscal and monetary policies.

As a result of the extent and diversity of the risks the Company faces in its business operations, we analyze risk and risk concentration at transaction, portfolio, business, and enterprise-wide levels to ensure that material risks are identified and managed effectively. We utilize numerous methods to evaluate and measure risks. In general, we evaluate risks in terms of the impact on our economic value, earnings, liquidity, strategic objectives, credit rating, reputation, and values. We identify and evaluate risks based not only on their probability of occurring and magnitude of impact on the financial statements, but also with respect to the potential for significant or unexpected shifts in market conditions or rules.

We recognize the importance of managing risk as a key differentiator in the energy business and view the active and effective management of the risks in our businesses to be of paramount importance. To foster a culture of risk awareness and management, we employ a risk management framework to identify, assess, monitor, manage, and report risks. Our risk management program is based on established policies and procedures to manage risks, combined with an extensive system of internal controls. Nevertheless, no system of risk management can cost-effectively eliminate all risks to which an entity is exposed. Thus, in particular environments, the Company may not be able to mitigate risk exposures to the level desired and may have exposures to certain risk factors that cannot be mitigated.

In this section, we will review the Company's risk in terms of our:

- risk governance,
- risk controls, and
- risk exposures.

Risk Governance

The Audit Committee of the Board of Directors periodically reviews compliance with our risk parameters, limits, and trading guidelines and our Board of Directors has established a VaR limit. As discussed below, senior management is responsible for monitoring the key risks, facilitated by a Risk Management Group (RMG). Our RMG is responsible for enforcing compliance with risk management policies and risk limits, as well as managing credit risk. The RMG reports to the Chief Risk Officer, who provides regular risk management updates to the Audit Committee and the Board of Directors.

We also have a Risk Management Committee (RMC) that is responsible for establishing risk management policies, reviewing procedures for the identification, assessment, measurement, and management of risks, and monitoring and reporting risk exposures. The RMC meets on a regular basis and is chaired by our Chief Executive Officer, and consists of our Chief Risk Officer, Chief Financial Officer, Vice Chairman, General Counsel, Chief Human Resources Officer, head of Corporate Strategy and Development, head of Corporate Affairs, Public, and Environmental Policy and business unit leaders. In addition, the Chief Risk Officer coordinates with the risk management committees at the business units that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

In an effort to manage market and credit risks, Constellation Energy has established a series of limits that reflect the Company's risk tolerances in the context of the market environment and our business strategy. In setting limits, the Company takes into consideration factors such as market volatility, product liquidity, business trends, and management experience. The Company maintains different limits at the corporate and business unit levels. Business units are responsible for adhering to established limits, against which exposures are monitored and reported. Limit breaches are reported in a timely manner to senior management, who consults with the business unit on an appropriate course of action.

Risk Controls

Risk controls are applied at the level of individual exposures and portfolios of exposures in each business and to risk in aggregate, across all businesses and major risk types, relative to the Company's risk capacity.

Constellation Energy's RMG is an independent function tasked with providing an independent quantification and assessment of key business risks, as well as providing an evaluation of individual risk components that contribute to the Company's consolidated risk profile. The RMG is also responsible for establishing risk policies, maintaining appropriate risk controls, ensuring compliance with policies and procedures, and monitoring methods according to the risk parameters established by the Board of Directors.

The RMG consists of six divisions that focus on a specialized area of risk.

Credit Risk Management

Credit Risk Management is responsible for managing the risk of loss inherent in the business units stemming from counterparty or customer failures and adverse market events that effect counterparty creditworthiness. This group supports the business units by establishing credit relationships with various wholesale counterparties and retail customers and facilitating market liquidity with credit limits and appropriate contractual credit terms and conditions. Credit risk managers are responsible for managing credit risk associated with our business activities, including establishing limits and contractual structures, as well as establishing and enforcing credit policies.

Market Risk Management

Market Risk Management is responsible for effectively identifying, quantifying, monitoring, and reporting on impacts of market risk, to include price volatility, correlations, volume uncertainty, market liquidity, interest rate and currency exposure on company businesses. The market risk group also enforces the

Market Risk policies and ensures compliance with these policies, including the monitoring, analyzing, and escalating of market risk controls. This group also develops market risk measurement tools, such as stress and scenario tests, gross margin-at-risk, and assists the businesses in implementing market strategies with the highest benefits.

Collateral Risk Management
Collateral Risk Management is responsible for providing an integrated view on credit, market, and company liquidity risks to facilitate Treasury's management of the Company's collateral and overall liquidity position. This group's responsibilities include measuring and monitoring collateral flows, downgrade collateral needs, and collateral use across the Company. Additionally, this group forecasts expected collateral requirements as well as estimates potential collateral requirements due to market shifts, hedging strategies, and adjustments to the Company's credit ratings. Finally, Collateral Risk Management assists the businesses in determining the strategic use of collateral and the appropriate cost of collateral for transactions. The group also works closely with the Treasury function to plan for expected and contingent liquidity needs based on the Company's long-term business plan.

Operational Risk Management
Each business area maintains responsibility for operational risk management. A corporate staff oversees implementation of a common framework for defining, measuring, monitoring, and reporting operational risks.

Corporate Audit
Corporate Audit assists in ensuring that controls put in place by management to mitigate the risks of the business are adequate and functioning appropriately. This group supports the risk assessment process including the analysis of inherent and residual risk, performs risk-based audits as approved by the Audit Committee of the Board of Directors, and supports the improvement of the effectiveness and efficiency of key business processes.

Risk Infrastructure
Risk Infrastructure supports the risk management divisions and consolidates risk exposures across the businesses and disciplines. This group's responsibilities include risk and credit systems design and maintenance, risk metric development and calculation, controls structure and enforcement, and risk reporting. In addition, the Risk Infrastructure Group provides analytical support to the risk functions, validates company models, and verifies liquid and illiquid forward price curves and volatilities. Finally, this group performs independent risk assessments, due diligence, and risk adjusted valuations of transactions, mergers and acquisitions, and large capital projects.

Risk Exposures
We manage risks across our merchant energy, regulated electric, and regulated gas businesses. We summarize below the risks we manage within each of our businesses.

Merchant Energy Business
Our merchant energy business is exposed to various risks in the competitive marketplace that may materially impact our financial results and affect our earnings. These risks include changes in commodity prices, potential imbalances in supply and demand, credit risk and operational risk.

Regulated Electric Business
BGE does not own or operate any electric generating facilities. Therefore, BGE's regulated electric business is exposed to market price risk. To mitigate this, BGE obtains energy and capacity to provide SOS through a competitive bidding process approved by the Maryland PSC. We discuss SOS and the impact on base rates in more detail in *Item 1. Business—Baltimore Gas and Electric Company—Electric Business* section. As a result of this process, BGE's exposure to market price risk is limited, and at December 31, 2009, our exposure to commodity price risk for our regulated electric business was not material. However, BGE may enter into electric futures, options, and swaps to hedge its market price risk if appropriate. We discuss this further in *Note 13 to Consolidated Financial Statements*.

BGE's regulated electric business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

Regulated Gas Business
BGE acquires all of its natural gas for delivery to customers from third party suppliers. Therefore, BGE's regulated gas business is exposed to market price risk. However, BGE recovers the costs of purchased gas under the market-based rates incentive mechanism approved by the Maryland PSC. Additionally, BGE may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program as appropriate. We discuss this further in *Note 13 to Consolidated Financial Statements*. At December 31, 2009, our exposure to commodity price risk for our regulated gas business was not material.

BGE's regulated gas business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

Risk Exposure Categories
The various categories of risk exposures that we manage include, but are not limited to, market risk, which includes interest rate risk, security price risk, and foreign currency risk; credit risk, which includes wholesale and retail; operational risk and funding liquidity risk. As previously noted, these risks may be common to more than one of our businesses. We discuss each of these primary risk exposure categories separately below.

Market Risk
We are exposed to the impact of market fluctuations in the price and transportation costs of power, natural gas, coal, and other related commodities. These risks arise from our ownership and

operation of power plants, our customer supply operations, and our origination, risk management, and trading activities. These commodity price risks arise from:

- the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other related commodities,
- changes in market volatilities or correlations, and
- changes in interest and foreign exchange rates.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and products in our merchant energy business, and if we do not hedge the associated financial exposure, this commodity price volatility could adversely affect our economic value or earnings. These factors include:

- seasonal, daily, and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- procedures used to maintain the integrity of the physical power system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- geopolitical concerns affecting global supply of coal, oil, and natural gas.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary as a result of regional differences in:

- weather conditions,
- market liquidity,
- capability and reliability of the physical power and gas systems, and
- the nature and extent of power market restructuring.

Additionally, we have fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Our power generation facilities purchase fuel under contracts or in the spot market. Fuel prices may be volatile, and the price that can be obtained from electricity sales may not change at the same rate or in the same direction as changes in fuel costs. This could have a material adverse impact on our financial results.

As part of our overall portfolio, we manage the market risk of our merchant energy business, including electricity sales, fuel and energy purchases, emission credits, interest rate, foreign currency, weather, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales and purchases of energy, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future,
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date,
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity, and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers,
- managing our collateral requirements, and
- managing our exposure to interest rate and foreign currency exchange risks.

The portion of forecasted transactions hedged may vary based upon management's assessment of market conditions, weather, operational, and other factors.

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, historical price relationships, and credit exposure. However, it is likely that future market prices could vary from those used in recording derivative assets and liabilities subject to mark-to-market accounting, and such variations could be material.

Power, gas, coal, and other related commodity trading risks involve the potential decline in net income or financial condition due to adverse changes in market prices, whether arising from customer activities, generating plants, or proprietary positions taken by the Company. We assess and monitor market risk with a variety of tools, including EVaR, VaR, scenario analysis, and stress testing.

EVaR:
EVaR measures the potential pre-tax loss in the fair value of the merchant energy business due to changes in market risk factors. EVaR is a one-day value-at-risk measure calculated at a 95% confidence level assuming a standard normal distribution of prices over the most recent rolling 3-month period. EVaR includes all positions over a forward rolling 60-month time horizon that expose us to market price risk, regardless of accounting treatment and business line.

Positions included in EVaR are comprised of all positions, regardless of accounting treatment, that create market risk including:

- derivative and nonderivative commodity contracts associated with our Generation, Customer Supply, and Global Commodities operations,
- physical assets, such as our owned and contractually-controlled generating plants, and
- our share of investments in generating plants.

We include the positions related to physical assets to provide a more complete presentation of our commodity market risk exposures. EVaR includes illiquid products and positions for which there is limited price discovery. Modeling the positions in our Generation and Customer Supply operations involves a number of assumptions, and includes projections of generation, emission rates and costs, customer load growth, load response to weather, and customer response to competitive supply. Changes in our forecast or management estimates will affect the fair value of these positions in a manner not captured by EVaR.

EVaR reflects the risk of loss due to market prices under normal market conditions. An inherent limitation of our value-at-risk measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from the past. We use stress tests and scenario analysis to better understand extreme events as a complement to EVaR. This includes exposure to unlikely but plausible events in abnormal markets, sensitivity to changes in management projections of customer demand or forecasted generation output, and price sensitivity to illiquid points and regional basis spreads.

EVaR is monitored daily and is subject to regional and overall guidelines for the Customer Supply operations. We place guidelines on the risk associated with illiquid delivery locations and regional basis within our Customer Supply operation. Additionally, we monitor generation plant hedge ratios relative to guidelines specified by management. Stress tests and scenario analysis are conducted regularly and the results, trends, and explanations are reviewed by senior management and risk committees.

The EVaR amounts below represent the potential pre-tax change in the fair values of our merchant energy business positions over a one-day holding period.

EVaR

For the year ended December 31,	**2009**	2008
	(In millions)	
95% Confidence Level, One-Day Holding Period		
Year end	**$73.0**	$135.6
Average	**92.8**	N/A
High	**122.8**	N/A
Low	**64.1**	N/A

N/A—Average, high, and low amounts for 2008 are not available as we did not begin computing those categories of EVaR until the fourth quarter of 2008.

At December 31, 2009, our EVaR was approximately $73 million, which represents a 46% decline from its level of $136 million on December 31, 2008, mainly due to de-risking activities and the closing of the EDF transaction in the last quarter of the year.

VaR:
VaR measures the potential pre-tax loss in the fair value of mark-to-market energy contracts due to changes in market risk factors. VaR is a one-day value-at-risk measure calculated at a 95% confidence level assuming a standard normal distribution of prices over the most recent rolling 3-month period. VaR includes all positions subject to mark-to-market accounting, including contracts that hedge the economics of Customer Supply nonderivative power and fuel contracts, but which do not receive hedge accounting treatment, but also contracts designated for trading. Thus, the positions for which we monitor VaR are included within, and are not incremental, to the positions subject to EVaR.

VaR and EVaR have similar limitations. VaR may include some products and positions for which there is limited price discovery or market depth. The modeling of option positions included in VaR involves a number of assumptions and approximations. An inherent limitation of our VaR measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from that of the past.

The VaR amounts below represent the potential pre-tax loss in the fair value of our merchant energy business positions subject to mark-to-market accounting, including both trading and non-trading activities, over one and ten-day holding periods.

During 2009, 99% Confidence Level, One-Day Holding Period mark-to-market VaR represented in the table below ranged between a high of $55.5 million in the beginning of the year and a low of $5.0 million towards the end of the year. Despite the wide range of values during 2009, mark-to-market VaR has been declining steadily throughout the year, consistent with our de-risking efforts. While de-risking activities were the main contributor to the declining level of mark-to-market VaR, this metric will continue to be impacted by the volatility of commodity prices and by the size of mark-to-market positions of our non-trading activities.

Total Mark-to-Market VaR *For the year ended December 31,*	**2009**	2008
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 8.0**	$19.7
Average	**18.1**	26.1
High	**55.5**	38.0
Low	**5.0**	19.7
95% Confidence Level, One-Day Holding Period		
Year end	**$ 6.1**	$15.0
Average	**13.8**	19.9
High	**42.2**	28.9
Low	**3.8**	15.0
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 19.2**	$47.5
Average	**43.7**	62.8
High	**133.6**	91.5
Low	**12.0**	47.5

Constellation Energy's proprietary trading activities are substantially reduced from previous years and are now immaterial. These activities continue to be managed with daily VaR limits, stop loss limits and position limits.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt and certain related interest rate swaps. We may use derivative instruments to manage our interest rate risks.

In July 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps relating to $450.0 million of our long-term debt. These fair value hedges effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three month London Inter-Bank Offered Rate. In July 2009, we terminated an interest rate swap relating to $50 million of the $450 million of fixed-rate debt. Including the $400.0 million in interest rate swaps, approximately 13% of our long-term debt is floating-rate.

We discuss our use of derivative instruments to manage our interest rate risk in more detail in *Note 13 to Consolidated Financial Statements*.

The following table provides information about our debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2010	2011	2012	2013	2014	Thereafter	Total	Fair value at December 31, 2009
				(Dollars in millions)				
Long-term debt								
Variable-rate debt	$ —	$ —	$ 246.9	$ —	$ —	$ 403.0	$ 649.9	$ 649.9
Average interest rate (A)	—%	—%	3.16%	—%	—%	1.22%	1.96%	
Fixed-rate debt	$ 56.9	$81.8	$ 676.9	$466.6	$ 90.4	$2,852.4	$4,225.0	$4,433.1
Average interest rate	5.68%	5.95%	6.84%	6.06%	5.33%	6.61%	6.53%	

(A) Interest on variable rate debt is included based on the forward curve for interest rates at December 31, 2009.

Security Price Risk

We are exposed to price fluctuations in financial markets primarily through our pension plan assets. In 2009, our actual gain on pension plan assets was $217.6 million. We describe our pension funding requirements in more detail in *Note 7 to Consolidated Financial Statements*.

Foreign Currency Risk

Our merchant energy business is exposed to the impact of foreign exchange rate fluctuations. This foreign currency risk arises from our activities in countries where we transact in currencies other than the U.S. dollar. In 2009, our exposure to foreign currency risk was not material. We manage our exposure to foreign currency exchange rate risk using a foreign currency hedging program. We will continue to have limited exposure to the Canadian dollar due to our Canadian gas and power operations.

Credit Risk

We are exposed to credit risk through our merchant energy business and BGE's operations. Credit risk is the loss that may result from counterparties' nonperformance and retail customer accounts receivable and forward value payment risk arising from contracted power and gas supply agreements. We evaluate our credit risk as discussed below.

Wholesale Credit Risk

We measure wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff. We monitor and manage the credit risk of our Global Commodities operation through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral, or prepayment arrangements, and the use of master netting agreements.

As of December 31, 2009 and 2008, counterparties in the credit portfolio of our Global Commodities operation had the following public credit ratings:

At December 31,	**2009**	2008
Rating		
Investment Grade (1)	**43%**	52%
Non-Investment Grade	**2**	15
Not Rated	**55**	33

(1) *Includes counterparties with an investment grade rating by at least one of the major credit rating agencies. If split rating exists, the lower rating is used.*

Our exposure to "Not Rated" counterparties was $1.5 billion at December 31, 2009 and December 31, 2008.

Many of our not rated counterparties are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $1.2 billion or 81% of the exposure to unrated counterparties was rated investment grade equivalent at December 31, 2009 and approximately $0.9 billion or 60% was rated investment grade equivalent at December 31, 2008. The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

At December 31,	**2009**	2008
Investment Grade Equivalent	**88%**	74%
Non-Investment Grade Equivalent	**12**	26

Our total exposure, net of collateral, to counterparties across our entire wholesale portfolio is $2.8 billion as of December 31, 2009. The top ten counterparties account for approximately 52% of our total exposure with approximately 5% of that exposure being non-investment grade.

If a counterparty were to default on its contractual obligations and we were to liquidate transactions with that entity, our potential credit loss would include all forward and settlement exposure plus any additional costs related to termination and replacement of the positions. This would include contracts accounted for using the mark-to-market, hedge, and accrual accounting methods, the amount owed or due from settled transactions, less any collateral held from the counterparty. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact on our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. To reduce our credit risk with counterparties, we attempt to enter into agreements that allow us to obtain collateral on a contingent basis, seek third party guarantees of the counterparty's obligation, and enter into netting agreements that allow us to offset receivables and payables with forward exposure across many transactions.

As of December 31, 2009, our total exposure of $2.8 billion, net of collateral, includes accrual positions and derivatives. This total exposure has declined significantly from the $4.5 billion as of December 31, 2008, as a result of our de-risking activities and divestitures and changes in commodity prices. Of our $2.8 billion total exposure at December 31, 2009, less than $1 billion is recorded on our Consolidated Balance Sheets.

Immediately preceding the EDF transaction, our Global Commodities operation entered into long term PPA agreements with CENG, creating a counterparty exposure (net of payables owed) exceeding 10% of our total credit exposure. We discuss our counterparty credit risk in more detail in *Note 1 to Consolidated Financial Statements*. Other than the exposure to CENG, no single counterparty concentration comprises more than 10% of the total exposures recorded on our Consolidated Balance Sheets as of December 31, 2009.

Due to volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the power our Global Commodities operation had contracted for), we could incur a loss that could have a material impact on our financial results.

If a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of derivative contracts recorded at fair value, the amount owed for settled transactions, and additional payments, if any, that we would have to make to settle unrealized losses on accrual contracts. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact in our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. These potential losses would be limited to the extent that the in-the-money amount exceeded any credit mitigants such as cash, letters of credit, or parental guarantees supporting the counterparty obligation.

We also enter into various wholesale transactions through ISOs. These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These ISOs have established credit policies and practices to mitigate the exposure of counterparty credit risks. As a market participant, we continuously assess our exposure to the credit risks of each ISO.

BGE is exposed to wholesale credit risk of its suppliers for electricity and gas to serve its retail customers. BGE may receive performance assurance collateral to mitigate electricity suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a full-requirements service agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates.

Retail Credit Risk

We are exposed to retail credit risk through our competitive electricity and natural gas supply activities, which serve commercial and industrial companies and governmental entities, and through BGE's electricity and natural gas distribution operations. Retail credit risk results when customers default on their contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers of our nonregulated retail businesses.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures, and the use of credit mitigation measures such as letters of credit or prepayment arrangements. In addition, we have taken steps to augment our credit staff in response to current economic conditions.

Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted.

Our retail credit portfolio is diversified with no significant company, geographic, or industry concentrations. In 2008, reserve levels had been increased across our retail businesses due to indicators of deteriorating credit quality and macroeconomic slowdown. In the first half of 2009, the overall incidence of customer bankruptcies increased, but had moderated to more historic levels by year end. Sectors most susceptible to financial stress were concentrated in consumer cyclical industries and commercial real estate. As a result, we have increased our reserve levels accordingly. We have also augmented our credit risk organization with a dedicated credit workout function.

BGE is subject to retail credit risk associated with both the delivery portion of a customer's bill as well as on the uncollectible expense or credit risk from the gas and/or electric commodity portion of the bills of those customers to whom BGE sells the gas and electric commodity. Although both BGE's delivery and commodity rates include some level of costs for uncollectible customer accounts receivable expenses, full recovery is contingent on amounts approved by the Maryland PSC in customer rates and, therefore is not guaranteed and BGE is exposed to these potential losses and related carrying costs.

Operational Risk

Operational risk is the risk associated with human error or a failure of our processes and systems, or external factors. We are exposed to many types of operational risks, including the risk of fraud by employees or outsiders, clerical and record-keeping errors, and computer systems malfunctions. In addition, we may also be subject to disruptions in our operating systems arising from events that are wholly or partially beyond our control, such as natural disasters, acts of terrorism, and computer viruses, which may give rise to losses in service to customers and/or monetary losses to us.

We own, have direct and indirect ownership interests in, and/or operate a number of power generation facilities, which utilize a diverse mix of fuel sources to include coal, gas, oil, hydro, biomass, and nuclear. We are exposed to risk resulting from generating plants not being available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sales commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices. We purchase electricity from generating facilities we do not own. If one or more of those generating facilities were unable to produce electricity due to operational factors, we may be forced to purchase electricity in the wholesale market at higher prices. This could have a material adverse impact on our financial results.

CENG, an entity in which we own a 50.01% membership interest, owns nuclear plants. These nuclear plants produce electricity at a relatively low marginal cost. Nine Mile Point Unit 2 and the Ginna facility sell approximately 90% of their respective output under unit-contingent power purchase agreements (CENG has no obligation to provide power if the units are not available) to the previous owners. However, if an unplanned outage were to occur at Calvert Cliffs during periods when demand was high, CENG may have to purchase replacement power at potentially higher prices to meet their obligations, which could have a material adverse impact on CENG's and our financial results.

We are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us to purchase additional energy at higher prices. Alternatively, during periods of low demand, our electricity supplies may exceed our customers' needs and could result in us selling that excess energy at lower prices. Either of those circumstances could have a negative impact on our financial results.

We are also exposed to variations in the prices and required volumes of natural gas, oil, and coal we burn at our power plants to generate electricity. Therefore, high commodity prices increase the impact of generator outages and variable load, but as long as the electricity and fuel prices move in tandem, we have limited exposure to changing commodity prices. During periods of high demand on our generation assets, our fuel supplies may be insufficient and could require us to procure additional fuel at higher prices. Alternatively, during periods of low demand on our generation assets, our fuel supplies may exceed our needs, and could result in us selling the excess fuels at lower prices. Either of these circumstances will have a negative impact on our financial results.

Funding Liquidity Risk

Funding liquidity risk relates to the ability to fund current and future obligations of the company given variability in collateral requirements as well as variability around working capital requirements and other cash flows that may affect our liquidity. To assess funding liquidity risk, we distinguish between sources and uses of liquidity. Sources of liquidity include projected net available cash, the unused capacity available from our credit facilities, and any availability under the EDF put arrangement through December 31, 2010. Uses include expected and contingent collateral requirements as well as any unexpected variation of cash flows from projected levels. We define contingent requirements to be any incremental or decremental requirements to expected requirement levels.

To manage liquidity risk, we quantify sources of liquidity and the expected and contingent uses of liquidity both over a short-term and long-term horizon. Contingent uses of liquidity are determined by stress-testing our portfolio using a simulation of extreme, adverse price stresses and measuring their combined impact on collateral needs and on cash flows related to losses due to market and credit risk. Liquidity stresses related to operational risks (weather, plant outages) and other business risks not directly linked to price moves are assessed on a regular basis using scenario analysis. Results of the liquidity assessment are shared regularly with senior management.

Liquidity risk assessment has been integrated into our strategic planning process. Expected and contingent funding needs implied by the business plans of our various business units are first aggregated and compared to available liquidity sources over the planning horizon. Capital and liquidity sources are then allocated to business units based on their business plans, taking into account the cost of providing liquidity. We believe that this integrated view on sources and uses of liquidity allows us to ensure proper funding of the business in accordance with our business plan.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item with respect to market risk is set forth in *Item 7* of Part II of this Form 10-K under the heading *Risk Management*.

REPORTS OF MANAGEMENT

Financial Statements

The management of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company (the "Companies") is responsible for the information and representations in the Companies' financial statements. The Companies prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the financial statements and expressed their opinion on them. They performed their audit in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Audit Committee of the Board of Directors, which consists of four independent Directors, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

Management's Report on Internal Control Over Financial Reporting—Constellation Energy Group, Inc.

The management of Constellation Energy Group, Inc. (Constellation Energy), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Constellation Energy's system of internal control over financial reporting is designed to provide reasonable assurance to Constellation Energy's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of Constellation Energy conducted an evaluation of the effectiveness of Constellation Energy's internal control over financial reporting using the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that Constellation Energy's internal control over financial reporting was effective as of December 31, 2009.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of Constellation Energy's internal control over financial reporting as of December 31, 2009, as stated in their report on the next page.

Mayo A. Shattuck III	Jonathan W. Thayer
Chairman of the Board, President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

Management's Report on Internal Control Over Financial Reporting—Baltimore Gas and Electric Company

The management of Baltimore Gas and Electric Company (BGE), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

BGE's system of internal control over financial reporting is designed to provide reasonable assurance to BGE's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of BGE conducted an evaluation of the effectiveness of BGE's internal control over financial reporting using the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that BGE's internal control over financial reporting was effective as of December 31, 2009.

This annual report does not include an attestation report of BGE's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by BGE's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit BGE, as a non-accelerated filer, to provide only management's report in this annual report.

Kenneth W. DeFontes, Jr.	Kevin W. Hadlock
President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

To the Board of Directors and Shareholders of
Constellation Energy Group, Inc.

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and its subsidiaries (the Company) at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in *Note 1* to the consolidated financial statements, in 2009 the Company changed its method of presenting noncontrolling interests. As discussed in *Note 13* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value and classifying certain collateral balances. As discussed in *Note 1* to the consolidated financial statements, in 2007 the Company changed its method of accounting for uncertain tax positions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with 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 (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.

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.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Constellation Energy Group, Inc. and its subsidiaries as of December 31, 2007, 2006 and 2005, and the related consolidated statements of income (loss), cash flows, and common shareholders' equity and comprehensive income (loss) for the years ended December 31, 2006 and 2005 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. and its subsidiaries included in the Selected Financial Data appearing under Item 6 for each of the five years in the period ended December 31, 2009, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 26, 2010

To Board of Directors and Shareholder of Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries (the Company) at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements 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 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in *Note 1* to the consolidated financial statements, in 2009 the Company changed its method of presenting noncontrolling interests. As discussed in *Note 13* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value. As discussed in *Note 1* to the consolidated financial statements, in 2007 the Company changed its method of accounting for uncertain tax positions.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Baltimore Gas and Electric Company and its subsidiaries as of December 31, 2007, 2006 and 2005, and the related consolidated statements of income and cash flows for the years ended December 31, 2006 and 2005 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company and its subsidiaries included in the Selected Financial Data appearing under Item 6 for each of the five years in the period ended December 31, 2009, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 26, 2010

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CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2009**	2008	2007
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$12,024.3**	$16,057.6	$17,786.5
Regulated electric revenues	**2,820.7**	2,679.5	2,455.6
Regulated gas revenues	**753.8**	1,004.8	943.0
Total revenues	**15,598.8**	19,741.9	21,185.1
Expenses			
Fuel and purchased energy expenses	**11,135.6**	15,521.3	16,473.9
Operating expenses	**2,228.0**	2,378.8	2,447.4
Merger termination and strategic alternatives costs	**145.8**	1,204.4	—
Impairment losses and other costs	**124.7**	741.8	20.2
Workforce reduction costs	**12.6**	22.2	2.3
Depreciation, depletion, and amortization	**589.1**	583.2	557.8
Accretion of asset retirement obligations	**62.3**	68.4	68.3
Taxes other than income taxes	**290.4**	301.8	288.9
Total expenses	**14,588.5**	20,821.9	19,858.8
Equity Investment (Losses) Earnings	**(6.1)**	76.4	8.1
Gain on Sale of Interest in CENG	**7,445.6**	—	—
Net (Loss) Gain on Divestitures	**(468.8)**	25.5	—
Income (Loss) from Operations	**7,981.0**	(978.1)	1,334.4
Gain on Sales of CEP LLC Equity	**—**	—	63.3
Other (Expense) Income	**(140.7)**	(69.5)	157.4
Fixed Charges			
Interest expense	**437.2**	399.1	311.8
Interest capitalized and allowance for borrowed funds used during construction	**(87.1)**	(50.0)	(19.4)
Total fixed charges	**350.1**	349.1	292.4
Income (Loss) from Continuing Operations Before Income Taxes	**7,490.2**	(1,396.7)	1,262.7
Income Tax Expense (Benefit)	**2,986.8**	(78.3)	428.3
Income (Loss) from Continuing Operations	**4,503.4**	(1,318.4)	834.4
Loss from discontinued operations, net of income taxes of $1.5	**—**	—	(0.9)
Net Income (Loss)	**4,503.4**	(1,318.4)	833.5
Net Income (Loss) Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**60.0**	(4.0)	12.0
Net Income (Loss) Attributable to Common Stock	**$ 4,443.4**	$ (1,314.4)	$ 821.5
Average Shares of Common Stock Outstanding—Basic	**199.3**	179.1	180.2
Average Shares of Common Stock Outstanding—Diluted	**200.3**	179.1	182.5
Earnings (Loss) Per Common Share from Continuing Operations—Basic	**$ 22.29**	$ (7.34)	$ 4.56
Loss from discontinued operations	**—**	—	(0.01)
Earnings (Loss) Per Common Share—Basic	**$ 22.29**	$ (7.34)	$ 4.55
Earnings (Loss) Per Common Share from Continuing Operations—Diluted	**$ 22.19**	$ (7.34)	$ 4.51
Loss from discontinued operations	**—**	—	(0.01)
Earnings (Loss) Per Common Share—Diluted	**$ 22.19**	$ (7.34)	$ 4.50
Dividends Declared Per Common Share	**$ 0.96**	$ 1.91	$ 1.74

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2009**	2008
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 3,440.0**	$ 202.2
Accounts receivable (net of allowance for uncollectibles of **$160.6** and $240.6, respectively)	**2,137.6**	3,389.9
Fuel stocks	**314.9**	717.9
Materials and supplies	**93.3**	224.5
Derivative assets	**639.1**	1,465.0
Unamortized energy contract assets (includes $371.3 million related to CENG)	**436.5**	81.3
Restricted cash	**27.0**	1,030.5
Deferred income taxes	**127.9**	268.0
Other	**244.4**	815.5
Total current assets	**7,460.7**	8,194.8
Investments and Other Noncurrent Assets		
Nuclear decommissioning trust funds	**—**	1,006.3
Investment in CENG	**5,222.9**	—
Other investments	**424.3**	421.0
Regulatory assets (net)	**414.4**	494.7
Goodwill	**25.5**	4.6
Derivative assets	**633.9**	851.8
Unamortized energy contract assets (includes $400.9 million related to CENG)	**604.7**	173.1
Other	**304.2**	421.3
Total investments and other noncurrent assets	**7,629.9**	3,372.8
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**5,784.6**	8,866.2
Regulated property, plant and equipment	**6,749.9**	6,419.4
Nuclear fuel (net of amortization)	**—**	443.0
Accumulated depreciation	**(4,080.7)**	(5,012.1)
Net property, plant and equipment	**8,453.8**	10,716.5
Total Assets	**$23,544.4**	$22,284.1

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

At December 31,	**2009**	2008
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 46.0**	$ 855.7
Current portion of long-term debt	**56.9**	2,591.5
Accounts payable and accrued liabilities	**1,262.4**	2,370.1
Customer deposits and collateral	**103.3**	120.3
Derivative liabilities	**632.6**	1,241.8
Unamortized energy contract liabilities	**390.1**	393.5
Accrued taxes	**877.3**	51.1
Accrued expenses	**297.9**	322.0
Other	**374.2**	514.2
Total current liabilities	**4,040.7**	8,460.2
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**3,205.5**	677.0
Asset retirement obligations	**29.3**	987.3
Derivative liabilities	**674.1**	1,115.0
Unamortized energy contract liabilities	**653.7**	906.4
Defined benefit obligations	**743.9**	1,354.3
Deferred investment tax credits	**32.0**	44.1
Other	**388.8**	249.6
Total deferred credits and other noncurrent liabilities	**5,727.3**	5,333.7
Long-term Debt, Net of Current Portion	**4,814.0**	5,098.7
Equity		
Common shareholders' equity	**8,697.1**	3,181.4
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**75.3**	20.1
Total equity	**8,962.4**	3,391.5
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$23,544.4**	$22,284.1

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Cash Flows From Operating Activities			
Net income (loss)	**$ 4,503.4**	$(1,318.4)	$ 833.5
Adjustments to reconcile to net cash provided by operating activities			
Depreciation, depletion, and amortization	**589.1**	583.2	557.8
Amortization of nuclear fuel	**117.9**	123.9	114.3
Amortization of energy contracts and derivatives designated as hedges	**(138.4)**	(256.3)	(222.9)
All other amortization	**135.7**	40.5	11.2
Accretion of asset retirement obligations	**62.3**	68.4	68.3
Deferred income taxes	**1,846.9**	(122.8)	226.2
Investment tax credit adjustments	**(12.1)**	(6.4)	(6.7)
Deferred fuel costs	**68.9**	52.0	(248.0)
Defined benefit obligation expense	**85.3**	99.6	111.8
Defined benefit obligation payments	**(372.5)**	(120.4)	(165.4)
Merger termination and strategic alternatives costs	**128.2**	541.8	—
Workforce reduction costs	**12.6**	22.2	2.3
Impairment losses and other costs	**124.7**	741.8	20.2
Impairment losses on nuclear decommissioning trust assets	**62.6**	165.0	8.5
Gain on sale of 49.99% membership interest in CENG	**(7,445.6)**	—	—
Gains on sale of CEP LLC equity	**—**	—	(63.3)
Loss (gain) on divestitures	**468.8**	(38.1)	—
Gains on termination of contracts	**—**	(73.1)	—
Accrual of BGE residential customer credit	**112.4**	—	—
Equity in earnings of affiliates less than dividends received	**15.5**	6.3	45.3
Derivative contracts classified as financing activities	**1,138.3**	(107.2)	32.2
Changes in working capital			
Accounts receivable, excluding margin	**543.3**	606.7	(664.2)
Derivative assets and liabilities, excluding collateral	**425.3**	(757.9)	(138.2)
Net collateral and margin	**1,522.8**	(960.3)	49.6
Materials, supplies, and fuel stocks	**220.6**	(33.5)	(66.4)
Other current assets	**217.2**	(95.4)	(18.5)
Accounts payable and accrued liabilities	**(1,105.0)**	(225.8)	448.8
Liability for unrecognized tax benefits	**102.1**	79.7	71.9
Other current liabilities	**788.8**	(238.1)	(14.0)
Other	**171.7**	(38.5)	(53.3)
Net cash provided by (used in) operating activities	**4,390.8**	(1,261.1)	941.0
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(1,529.7)**	(1,934.1)	(1,295.7)
Asset acquisitions and business combinations, net of cash acquired	**(41.1)**	(315.3)	(347.5)
Investments in nuclear decommissioning trust fund securities	**(385.2)**	(440.6)	(659.5)
Proceeds from nuclear decommissioning trust fund securities	**366.5**	421.9	650.7
Investments in joint ventures	**(201.6)**	—	—
Issuances of loans receivable	**—**	—	(19.0)
Proceeds from sale of 49.99% membership interest in CENG	**3,528.7**	—	—
Proceeds from sales of investments and other assets	**88.3**	446.3	13.9
Contract and portfolio acquisitions	**(2,153.7)**	—	(474.2)
Decrease (increase) in restricted funds	**1,003.3**	(942.8)	(109.9)
Other	**0.1**	21.7	(45.3)
Net cash provided by (used in) investing activities	**675.6**	(2,742.9)	(2,286.5)
Cash Flows From Financing Activities			
Net (maturity) issuance of short-term borrowings	**(809.7)**	813.7	14.0
Proceeds from issuance of common stock	**33.9**	17.6	65.1
Proceeds from issuance of long-term debt	**136.1**	3,211.4	698.2
Common stock dividends paid	**(228.0)**	(336.3)	(306.0)
Reacquisition of common stock	**—**	(16.2)	(409.5)
BGE preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Proceeds from contract and portfolio acquisitions	**2,263.1**	—	847.8
Repayment of long-term debt	**(1,986.8)**	(577.4)	(745.3)
Derivative contracts classified as financing activities	**(1,138.3)**	107.2	(32.2)
Debt and credit facility costs	**(98.4)**	(104.8)	—
Other	**12.7**	8.3	33.4
Net cash (used in) provided by financing activities	**(1,828.6)**	3,110.3	152.3
Net Increase (Decrease) in Cash and Cash Equivalents	**3,237.8**	(893.7)	(1,193.2)
Cash and Cash Equivalents at Beginning of Year	**202.2**	1,095.9	2,289.1
Cash and Cash Equivalents at End of Year	**$ 3,440.0**	$ 202.2	$ 1,095.9
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 369.5**	$ 341.4	$ 291.8
Income taxes	**$ 57.1**	$ 119.2	$ 282.4

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Years Ended December 31, 2009, 2008, and 2007	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2006	180,519	$2,738.6	$ 3,474.3	$(1,603.6)	$284.5	$ 4,893.8
Decrease in noncontrolling interests from deconsolidation					(74.1)	(74.1)
Comprehensive Income						
Net income			821.5		12.0	833.5
Other comprehensive income						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(682.3)				1,124.8		1,124.8
Net unrealized loss on hedging instruments, net of taxes of $408.2				(671.1)		(671.1)
Available-for-sale securities:						
Reclassification of net gains on securities from OCI to net income, net of taxes of $1.0				(1.6)		(1.6)
Net unrealized gain on securities, net of taxes of $(25.5)				26.5		26.5
Defined benefit plans:						
Net gain arising during period, net of taxes of $(7.8)				11.6		11.6
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(15.9)				24.6		24.6
Net unrealized gain on foreign currency translation, net of taxes of $(1.8)				7.0		7.0
Other				(10.8)		(10.8)
Total Comprehensive Income			821.5	511.0	12.0	1,344.5
Effect of adoption of uncertain tax position accounting standard			(7.3)			(7.3)
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($1.74 per share)			(368.4)			(368.4)
Common stock issued and share-based awards	1,789	184.2				184.2
Common stock purchased	(1,847)	(159.5)				(159.5)
Common stock purchased and retired	(2,024)	(250.0)				(250.0)
Other			(0.6)			(0.6)
Balance at December 31, 2007	178,437	2,513.3	3,919.5	(1,092.6)	209.2	5,549.4
Increase in noncontrolling interests from consolidation of a VIE					18.1	18.1
Comprehensive Loss						
Net loss			(1,314.4)		(4.0)	(1,318.4)
Other comprehensive loss						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(120.2)				200.6		200.6
Net unrealized loss on hedging instruments, net of taxes of $561.6				(875.3)		(875.3)
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(79.1)				81.7		81.7
Net unrealized losses on securities, net of taxes of 189.8				(197.5)		(197.5)
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $4.9				(7.2)		(7.2)
Net loss arising during period, net of taxes of $229.2				(339.9)		(339.9)
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(14.9)				21.3		21.3
Net unrealized loss on foreign currency translation, net of taxes of $0.1				(3.1)		(3.1)
Other				0.2		0.2
Total Comprehensive Loss			(1,314.4)	(1,119.2)	(4.0)	(2,437.6)
Effect of adoption of fair value measurement accounting standard			0.9			0.9
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($1.91 per share)			(341.3)			(341.3)
Common stock issued and share-based awards *	21,406	667.3	(35.8)			631.5
Common stock purchased	(200)	(16.1)				(16.1)
Common stock purchased and retired	(514)	—				—
Other			(0.2)			(0.2)
Balance at December 31, 2008	199,129	3,164.5	2,228.7	(2,211.8)	210.1	3,391.5

* *Includes 19,897.3 million shares issued to MidAmerican Energy Holdings Company.*

Certain prior-period amounts have been reclassified to conform with the current period's presentation.
See Notes to Consolidated Financial Statements.

continued on next page

Years Ended December 31, 2009, 2008, and 2007	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2008	199,129	$3,164.5	$ 2,228.7	$(2,211.8)	$210.1	$ 3,391.5
Contribution from noncontrolling interest					**8.0**	**8.0**
Other noncontrolling interest activity					**0.4**	**0.4**
Comprehensive Income						
Net income			**4,443.4**		**60.0**	**4,503.4**
Other comprehensive income						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(898.5)				**1,499.4**		**1,499.4**
Net unrealized loss on hedging instruments, net of taxes of $251.2				**(474.7)**		**(474.7)**
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(24.6)				**25.4**		**25.4**
Net unrealized gains on securities, net of taxes of $(78.2)				**77.7**		**77.7**
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $1.0				**(1.5)**		**(1.5)**
Net gains arising during period, net of taxes of $(23.9)				**26.9**		**26.9**
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)				**30.3**		**30.3**
Deconsolidation of CENG joint venture:						
Net unrealized gains on nuclear decommissioning trust funds, net of taxes of $125.3				**(125.3)**		**(125.3)**
Net unrealized losses on defined benefit plans, net of taxes of $(94.6)				**138.0**		**138.0**
Net unrealized gains on foreign currency translation, net of taxes of $(2.7)				**7.1**		**7.1**
Other comprehensive income—equity investment in CENG, net of taxes of $(11.7)				**12.9**		**12.9**
Other comprehensive income related to other equity method investees, net of taxes of $(1.3)				**2.1**		**2.1**
Total Comprehensive Income			**4,443.4**	**1,218.3**	**60.0**	**5,721.7**
BGE preference stock dividends					**(13.2)**	**(13.2)**
Common stock dividend declared ($0.96 per share)			**(192.2)**			**(192.2)**
Common stock issued and share-based awards	**1,856**	**65.1**	**(18.9)**			**46.2**
Balance at December 31, 2009	**200,985**	**$3,229.6**	**$ 6,461.0**	**$ (993.5)**	**$265.3**	**$ 8,962.4**

Certain prior-period amounts have been reclassified to conform with the current period's presentation.
See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Revenues			
Electric revenues	**$2,820.7**	$2,679.7	$2,455.7
Gas revenues	**758.3**	1,024.0	962.8
Total revenues	**3,579.0**	3,703.7	3,418.5
Expenses			
Operating expenses			
Electricity purchased for resale	**1,217.4**	1,078.1	360.8
Electricity purchased for resale from affiliate	**623.5**	802.0	1,139.6
Gas purchased for resale	**449.9**	694.5	639.8
Operations and maintenance	**433.7**	428.2	405.0
Operations and maintenance from affiliate	**126.2**	109.6	128.6
Impairment losses and other costs	**20.0**	—	—
Workforce reduction costs	**—**	6.4	—
Depreciation and amortization	**262.1**	227.9	234.2
Taxes other than income taxes	**177.8**	174.5	176.2
Total expenses	**3,310.6**	3,521.2	3,084.2
Income from Operations	**268.4**	182.5	334.3
Other Income	**25.4**	29.6	26.9
Fixed Charges			
Interest expense	**143.6**	144.2	127.9
Allowance for borrowed funds used during construction	**(4.3)**	(4.3)	(2.6)
Total fixed charges	**139.3**	139.9	125.3
Income Before Income Taxes	**154.5**	72.2	235.9
Income Taxes			
Current	**(119.8)**	(18.2)	(2.4)
Deferred	**184.7**	40.2	100.0
Investment tax credit adjustments	**(1.1)**	(1.3)	(1.6)
Total income taxes	**63.8**	20.7	96.0
Net Income	**90.7**	51.5	139.9
Preference Stock Dividends	**13.2**	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**$ 77.5**	$ 38.3	$ 126.7
Net Loss (Income) Attributable to Noncontrolling Interests	**7.3**	—	(0.1)
Net Income Attributable to Common Stock	**$ 84.8**	$ 38.3	$ 126.6

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2009**	2008
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 13.6**	$ 10.7
Accounts receivable (net of allowance for uncollectibles of **$46.2** and $33.3, respectively)	**311.7**	327.0
Accounts receivable, unbilled (net of allowance for uncollectibles of **$1.0** and $0.9, respectively)	**252.7**	232.3
Investment in cash pool, affiliated company	**314.7**	148.8
Accounts receivable, affiliated companies	**15.4**	4.3
Fuel stocks	**73.8**	143.7
Materials and supplies	**31.9**	38.4
Prepaid taxes other than income taxes	**49.5**	51.0
Regulatory assets (net)	**72.5**	79.7
Restricted cash	**24.3**	23.7
Deferred income taxes	**11.2**	—
Other	**11.3**	10.8
Total current assets	**1,182.6**	1,070.4
Investments and Other Assets		
Regulatory assets (net)	**414.4**	494.7
Receivable, affiliated company	**326.2**	161.1
Other	**98.2**	131.6
Total investments and other assets	**838.8**	787.4
Utility Plant		
Plant in service		
Electric	**4,772.4**	4,493.7
Gas	**1,260.6**	1,221.1
Common	**499.0**	476.3
Total plant in service	**6,532.0**	6,191.1
Accumulated depreciation	**(2,318.2)**	(2,191.0)
Net plant in service	**4,213.8**	4,000.1
Construction work in progress	**215.5**	225.7
Plant held for future use	**2.4**	2.6
Net utility plant	**4,431.7**	4,228.4
Total Assets	**$ 6,453.1**	$ 6,086.2

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2009**	2008
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 46.0**	$ 370.0
Current portion of long-term debt	**56.5**	90.0
Accounts payable and accrued liabilities	**166.0**	231.0
Accounts payable and accrued liabilities, affiliated companies	**98.3**	97.0
Customer deposits	**76.0**	72.3
Deferred income taxes	**—**	40.2
Accrued taxes	**80.2**	18.8
Residential customer rate credit	**112.4**	—
Accrued expenses and other	**96.1**	98.4
Total current liabilities	**731.5**	1,017.7
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,087.6**	843.3
Payable, affiliated company	**243.4**	243.2
Deferred investment tax credits	**9.5**	10.6
Liability for uncertain tax positions	**73.3**	5.5
Other	**20.0**	23.1
Total deferred credits and other liabilities	**1,433.8**	1,125.7
Long-term Debt		
Rate stabilization bonds	**510.9**	564.4
Other long-term debt of BGE	**1,431.5**	1,443.0
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated business	**—**	25.0
Unamortized discount and premium	**(2.2)**	(2.4)
Current portion of long-term debt	**(56.5)**	(90.0)
Total long-term debt	**2,141.4**	2,197.7
Equity		
Common shareholder's equity:		
Common stock	**912.2**	912.2
Retained earnings	**1,026.0**	625.4
Accumulated other comprehensive income	**0.6**	0.6
Total common shareholder's equity	**1,938.8**	1,538.2
Preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interest	**17.6**	16.9
Total equity	**2,146.4**	1,745.1
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$6,453.1**	$6,086.2

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 90.7**	$ 51.5	$ 139.9
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**262.1**	227.9	234.2
Other amortization	**9.2**	13.2	12.5
Deferred income taxes	**184.7**	40.2	100.0
Investment tax credit adjustments	**(1.1)**	(1.3)	(1.6)
Deferred fuel costs	**68.9**	52.0	(248.0)
Defined benefit plan expenses	**32.7**	30.6	39.8
Allowance for equity funds used during construction	**(8.2)**	(8.0)	(4.9)
Accrual of residential customer rate credit	**112.4**	—	—
Impairment losses and other costs	**20.0**	—	—
Workforce reduction costs	**—**	6.4	—
Changes in:			
Accounts receivable	**(5.1)**	(33.1)	(181.5)
Receivables, affiliated companies	**(11.1)**	(0.1)	(1.7)
Materials, supplies, and fuel stocks	**76.4**	(40.6)	9.6
Other current assets	**(10.2)**	(4.5)	25.9
Accounts payable and accrued liabilities	**(65.0)**	48.6	(4.9)
Accounts payable and accrued liabilities, affiliated companies	**1.3**	(67.5)	1.1
Other current liabilities	**(44.4)**	(11.4)	29.6
Long-term receivables and payables, affiliated companies	**(197.8)**	(45.7)	(42.0)
Other	**130.3**	(29.1)	(44.8)
Net cash provided by operating activities	**645.8**	229.1	63.2
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(372.6)**	(426.4)	(376.4)
Change in cash pool at parent	**(165.9)**	(70.4)	(17.8)
Sales of investments and other assets	**—**	12.9	0.8
(Increase) decrease in restricted funds	**(0.6)**	15.5	(42.3)
Net cash used in investing activities	**(539.1)**	(468.4)	(435.7)
Cash Flows From Financing Activities			
Net (repayment) issuance of short-term borrowings	**(324.0)**	370.0	—
Proceeds from issuance of long-term debt	**—**	400.0	623.2
Repayment of long-term debt	**(90.0)**	(350.0)	(124.8)
Debt issuance costs	**(0.5)**	(2.7)	—
Contribution from noncontrolling interest	**8.0**	—	—
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Contribution from (distribution to) parent	**315.9**	(171.7)	(106.0)
Net cash (used in) provided by financing activities	**(103.8)**	232.4	379.2
Net Increase (Decrease) in Cash and Cash Equivalents	**2.9**	(6.9)	6.7
Cash and Cash Equivalents at Beginning of Year	**10.7**	17.6	10.9
Cash and Cash Equivalents at End of Year	**$ 13.6**	$ 10.7	$ 17.6
Other Cash Flow Information:			
Cash paid (received) during the year for:			
Interest (net of amounts capitalized)	**$ 136.9**	$ 126.6	$ 126.3
Income taxes	**$(250.9)**	$ (5.1)	$ (37.6)

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). Our merchant energy business is a competitive provider of energy solutions for a variety of customers. BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries. References in this report to the "regulated business(es)" are to BGE.

Subsequent Event Policy

We evaluated events or transactions that occurred after December 31, 2009 for inclusion in these financial statements through February 26, 2010, the date these financial statements were issued.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation for two types of entities:

- subsidiaries in which we own a majority of the voting stock and exercise control over the operations and policies of the company, and
- variable interest entities (VIEs) for which we are the primary beneficiary, which means that we have a controlling financial interest in a VIE. We discuss our investments in VIEs in more detail in *Note 4*.

Consolidation means that we combine the accounts of these entities with our accounts. Therefore, our consolidated financial statements include our accounts, the accounts of our majority-owned subsidiaries that are not VIEs, and the accounts of VIEs for which we are the primary beneficiary. We have consolidated three VIEs for which we are the primary beneficiary. We eliminate all intercompany balances and transactions when we consolidate these accounts.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies where we hold approximately a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income (Loss). If our carrying value of the investment differs from our share of the investee's equity, we recognize this basis difference as an adjustment of our share of the investee's earnings.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. We recognize income only to the extent that we receive dividends or distributions. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Sale of Subsidiary Ownership Interests

We may sell portions of our ownership interests in a subsidiary's stock. Through 2008, we recorded any gains or losses in our Consolidated Statements of Income (Loss), as a component of non-operating income. Beginning in 2009, we treat sales of subsidiary stock as an equity transaction and do not recognize any gains or losses on the transaction as long as we retain a controlling financial interest.

When we sell ownership interests in our subsidiaries such that we do not retain a controlling financial interest, we deconsolidate that subsidiary. Upon deconsolidation, we recognize a gain or loss for the difference between the sum of the fair value of any consideration received and the fair value of our retained investment and the carrying amount of the former subsidiary's assets and liabilities.

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our nuclear generation and operation business, to EDF Group and affiliates (EDF). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG at that time. We account for our retained interest in CENG using the equity method. See *Note 2* for the gain recognized on our sale of a 49.99% interest in CENG to EDF.

Regulation of Electric and Gas Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we follow the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or the FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers.

When this happens, we and BGE must defer (include as an asset or liability in the Consolidated Balance Sheets and exclude from Consolidated Statements of Income (Loss)) certain regulated business expenses and income as regulatory assets and liabilities. We and BGE have recorded these regulatory assets and liabilities in the Consolidated Balance Sheets.

We summarize and discuss regulatory assets and liabilities further in *Note 6*.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- our revenues and expenses in our Consolidated Statements of Income (Loss) during the reporting periods,
- our assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements, and
- our disclosure of contingent assets and liabilities at the dates of the financial statements.

These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual amounts could materially differ from these estimates.

Reclassifications

In accordance with the requirements for the reporting of noncontrolling interests, which were effective on January 1, 2009 (see *Accounting Standards Adopted* section later in this note), we have separately presented:

- "Net income (loss) attributable to noncontrolling interests" on our, and BGE's, Consolidated Statements of Income (Loss),
- "Noncontrolling interests" and "BGE Preference Stock Not Subject to Mandatory Redemption" as noncontrolling interests on our Consolidated Balance Sheets,
- "Comprehensive income attributable to noncontrolling interests, net of taxes" in our Statements of Comprehensive Income (Loss), and
- "BGE preference stock dividends paid" in the financing section of our Consolidated Statements of Cash Flows.

We have also made the following reclassifications of prior year amounts for comparative purposes:

- We have separately presented "Equity investment (losses) earnings" that were previously reported within "Nonregulated revenues" on our Consolidated Statements of Income (Loss).
- We have separately presented "Accrued taxes" that was previously reported within "Accrued expenses" on our Consolidated Balance Sheets.
- We have separately presented "Liability for uncertain tax positions" that was previously reported within "Other long-term liabilities" on BGE's Consolidated Balance Sheets.
- We have separately presented "Electricity purchased for resale from affiliate" that was previously reported within "Electricity purchased for resale" on BGE's Consolidated Statements of Income.
- We have separately presented "Operations and maintenance from affiliate" that was previously reported within "Operations and maintenance" on BGE's Consolidated Statements of Income.

Revenues

<u>Sources of Revenue</u>

We earn revenues from the following primary business activities:

- sale of energy and energy-related products, including electricity, natural gas, and other commodities, in nonregulated markets;
- providing standard offer service and delivering electricity and natural gas to customers of BGE;
- trading energy and energy-related commodities; and,
- providing other energy-related nonregulated products and services.

We report BGE's revenues from standard offer service and delivery of electricity and natural gas to its customers as "Regulated electric revenues" and "Regulated gas revenues" in our Consolidated Statements of Income (Loss). We report all other revenues as "Nonregulated revenues."

Revenues from nonregulated activities result from contracts or other sales that generally reflect market prices in effect at the time that we executed the contract or the sale occurred. BGE's revenues from regulated activities reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's revenues below.

<u>Regulated Electric</u>

BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers standard offer service (SOS) rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Pursuant to Senate Bill 1, the energy legislation enacted in Maryland in June 2006, BGE suspended collection of the shareholder return component of the administrative fee for residential SOS service beginning January 1, 2007 for a 10-year period. However, under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, BGE reinstated collection of the residential return component of the SOS administration charge and began providing all residential electric customers a credit for the return component of the administrative charge. As part of the 2008 Maryland settlement agreement, which is discussed in more detail in *Note 2*, BGE resumed collection of the shareholder return portion of the residential standard offer service administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. BGE will cease collecting the residential shareholder return component again from June 1, 2010 through December 31, 2016. Senate Bill 1 imposed a 15% rate cap for

BGE residential electric customers from July 1, 2006 until May 31, 2007 and gave customers the option to further delay paying full market rates until January 1, 2008.

As part of the October 30, 2009 order from the Maryland PSC approving our transaction with EDF, BGE may file an electric distribution case at any time beginning in January 2010 and may not file a subsequent electric distribution rate case until January 2011. Any rate increase in the first electric distribution rate case will be capped at 5%.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." Under these clauses, BGE defers the difference between certain of its actual costs related to the gas commodity and what it collects from customers under the commodity charge in a given period for evaluation under a market-based rates incentive mechanism. For each period subject to that mechanism, BGE compares its actual cost of gas to a market index (a measure of the market price of gas for that period) and shares the difference equally between shareholders and customers through an adjustment to the price of gas service in future periods. This sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. As a condition to the October 30, 2009 order from the Maryland PSC approving our transaction with EDF, BGE may file a gas distribution case at any time beginning in January 2010 and may not file a subsequent gas distribution rate case until January 2011.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for recognizing revenues based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report revenues in our results of operations:

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record revenues in the period when we deliver energy commodities or products, render services, or settle contracts. We generally use accrual accounting to recognize revenues for our sales of electricity, gas, coal, and other commodities as part of our physical delivery activities. We enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to BGE's customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

However, we also use mark-to-market accounting rather than accrual accounting for recognizing revenue on our nonregulated retail gas customer supply activities and other physical commodity derivatives if we have not designated those contracts as NPNS.

We record accrual revenues from sales of products or services on a gross basis at the contract, tariff, or spot price because we are a principal to the transaction. Accrual revenues also include certain other gains and losses that relate to these activities or for which accrual accounting is required.

We include in accrual revenues the effects of hedge accounting for derivative contracts that qualify as hedges of our sales of products or services. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in revenues during the same period in which we record the revenues from the hedged transaction. We record any hedge ineffectiveness in revenues when it occurs. We discuss our hedge accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power sale agreements for which the contract price differs from current market prices. We also may designate a derivative as NPNS after its inception. We recognize the value of these derivatives in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into revenues based on the present value of the underlying cash flows provided by the contracts.

The following table summarizes the primary components of accrual revenues:

	Activity		
Component of Accrual Revenues	Nonregulated Physical Energy Delivery	Regulated Electricity and Gas Sales	Other Nonregulated Products and Services
Gross amounts receivable for sales of products or services based on contract, tariff, or spot price	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		
Amortization of acquired energy contract assets or liabilities	X		
Recovery or refund of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X	

Mark-to-Market Accounting
We record revenues using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting. These mark-to-market transactions primarily relate to our risk management and trading activities, our nonregulated retail gas customer supply activities, and economic hedges of other accrual activities. Mark-to-market revenues include:

- origination gains or losses on new transactions,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

Fuel and Purchased Energy Expenses

Sources of Fuel and Purchased Energy Expenses
We incur fuel and purchased energy costs for:

- the fuel we use to generate electricity at our power plants,
- purchases of electricity from others, and
- purchases of natural gas, coal, and other fuel types that we resell.

We report these costs in "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We also include certain fuel-related direct costs, such as ancillary services purchased from independent system operators, transmission costs, brokerage fees, and freight costs in the same category in our Consolidated Statements of Income (Loss).

Fuel and purchased energy costs from nonregulated activities result from contracts or other purchases that generally reflect market prices in effect at the time that we executed the contract or the purchase occurred. BGE's costs of electricity and gas for resale under regulated activities reflect actual costs of purchases, adjusted to reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's fuel and purchased energy expense below.

Regulated Electric
BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers SOS rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE's fuel and purchased energy expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual costs adjusted for the effects of the regulatory deferral mechanism.

Regulated Gas
BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." These clauses include a market-based rates incentive mechanism that requires BGE to compare its actual cost of gas to a market index (a measure of the market price of gas for that period) and share the difference equally between shareholders and customers. This sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period.

BGE defers the difference between the portion of its actual gas commodity costs subject to the market-based rates incentive mechanism and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the portion of this difference to which they are entitled through an adjustment to the price of gas service in future periods and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE's fuel and purchased energy expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual gas costs adjusted for the effects of the regulatory deferral mechanism.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for fuel and purchased energy costs based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report these costs in our Consolidated Statements of Income (Loss):

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record fuel and purchased energy expenses in the period when we consume the fuel or purchase the electricity or other commodity for resale. We use accrual accounting to recognize substantially all of our fuel and purchased energy expenses as part of our physical delivery activities. We make these purchases using a variety of instruments, including non-derivative transactions, derivatives that qualify for and are designated as NPNS, and spot-market purchases, including settlements with independent system operators. These transactions also include power purchase agreements that qualify as operating leases, for which fuel and purchased energy consists of both fixed capacity payments and variable payments based on the actual output of the plants. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

In certain cases, we use mark-to-market accounting rather than accrual accounting for recognizing fuel and purchased energy expenses on physical commodity derivatives if we have not designated those contracts as NPNS.

We include in accrual fuel and purchased energy expenses the effects of hedge accounting for derivative contracts that qualify as hedges of our fuel and purchased energy costs. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in fuel and purchased energy expenses during the same period in which we record the costs from the hedged transaction. We record any hedge ineffectiveness in expense when it occurs. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power purchase agreements or other contracts for which the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into fuel and purchased energy expenses based on the present value of the underlying cash flows provided by the contracts.

The following table summarizes the primary components of accrual purchased fuel and energy expense:

	Activity		
Component of Accrual Fuel and Purchased Energy Expense	**Nonregulated Physical Energy Delivery**	**Regulated Electricity and Gas Sales**	**Other Nonregulated Products and Services**
Actual costs of fuel and purchased energy	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		
Amortization of acquired energy contract assets or liabilities	X		
Deferral or amortization of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X	

Mark-to-Market Accounting

We record fuel and purchased energy expenses using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting in order to match the earnings impacts of those activities to the greatest extent permissible. These mark-to-market transactions primarily relate to our physical international coal purchase contracts. Mark-to-market costs include:

- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in "Fuel and purchased energy expense" in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

Derivatives and Hedging Activities

We engage in electricity, natural gas, coal, emission allowances, and other commodity marketing and risk management activities as part of our merchant energy business. In order to manage our exposure to commodity price fluctuations, we enter into energy and energy-related derivative contracts traded in the over-the-counter markets or on exchanges. These contracts include:

- forward physical purchase and sales contracts,
- futures contracts,
- financial swaps, and
- option contracts.

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances, to manage our exposure to fluctuations in interest rates on variable rate debt, and to optimize the mix of fixed and floating-rate debt. We use foreign currency swaps to manage our exposure to foreign currency exchange rate fluctuations.

Selection of Accounting Treatment

We account for derivative instruments and hedging activities in accordance with several possible accounting treatments for derivatives that meet all of the requirements of the accounting standard. Mark-to-market is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

The following are permissible accounting treatments for derivatives:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- NPNS.

Each of the accounting treatments for derivatives affects our financial statements in substantially different ways as summarized below:

Accounting Treatment	Recognition and Measurement	
	Balance Sheet	**Income Statement**
Mark-to-market	◆ Derivative asset or liability recorded at fair value	◆ Changes in fair value recognized in earnings
Cash flow hedge	◆ Derivative asset or liability recorded at fair value ◆ Effective changes in fair value recognized in accumulated other comprehensive income	◆ Ineffective changes in fair value recognized in earnings ◆ Amounts in accumulated other comprehensive income reclassified to earnings when the hedged forecasted transaction affects earnings or becomes probable of not occurring
Fair value hedge	◆ Derivative asset or liability recorded at fair value ◆ Book value of hedged asset or liability adjusted for changes in its fair value	◆ Changes in fair value recognized in earnings ◆ Changes in fair value of hedged asset or liability recognized in earnings
NPNS (accrual)	◆ Fair value not recorded ◆ Accounts receivable or accounts payable recorded when derivative settles	◆ Changes in fair value not recognized in earnings ◆ Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Mark-to-Market

We generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for derivatives related to the following physical energy delivery activities:

- our nonregulated retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges, in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

We may record origination gains associated with derivatives subject to mark-to-market accounting. Origination gains represent the initial fair value of certain structured transactions that our portfolio management and trading operation executes to meet the risk management needs of our customers. Historically, transactions that result in origination gains have been unique and resulted in individually significant gains from a single transaction. We generally recognize origination gains when we are able to obtain observable market data to validate that the initial fair value of the contract differs from the contract price.

Cash Flow Hedge

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery (generation and customer supply) activities because accrual accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. We only use fair value hedge accounting on a limited basis.

We use regression analysis to determine whether we expect a derivative to be highly effective as a cash flow hedge prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges have been effective. We perform these effectiveness tests prior to designation for all new hedges and on a daily basis for all existing hedges. We calculate the actual amount of ineffectiveness on our cash flow hedges using the "dollar offset" method, which compares changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge.

We discontinue hedge accounting when our effectiveness tests indicate that a derivative is no longer highly effective as a hedge; when the derivative expires or is sold, terminated or exercised; when the hedged item matures, is sold or repaid; or when we determine that the occurrence of the hedged forecasted transaction is not probable. When we discontinue hedge accounting but continue to hold the derivative, we begin to apply mark-to-market accounting at that time.

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we do not subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting. However, if we were to determine that a transaction designated as NPNS no longer qualified for the NPNS election, we would have to record the fair value of that contract on the balance sheet at that time and immediately recognize that amount in earnings.

Fair Value

We record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. As a result, often we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

The valuation adjustments we record include the following:

- Close-out adjustment—the estimated cost to close out or sell to a third party open mark-to-market positions. This valuation adjustment has the effect of valuing purchase contracts at the bid price and sale contracts at the offer price.
- Unobservable input valuation adjustment—necessary when we determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information.
- Credit spread adjustment—necessary to reflect the credit-worthiness of each customer (counterparty).

We discuss derivatives and hedging activities as well as how we determine fair value in detail in *Note 13*.

Balance Sheet Netting

We often transact with counterparties under master agreements and other arrangements that provide us with a right of setoff of amounts due to us and from us in the event of bankruptcy or default by the counterparty. We report these transactions on a net basis in our Consolidated Balance Sheets.

We apply balance sheet netting separately for current and noncurrent derivatives. Current derivatives represent the portion of derivative contract cash flows expected to occur within 12 months, and noncurrent derivatives represent the portion of those cash flows expected to occur beyond 12 months. Within each of these categories, we net all amounts due to and from each counterparty under master agreements into a single net asset or liability. We include fair value cash collateral amounts received and posted in determining this net asset and liability amount.

Unamortized Energy Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of non-derivative energy contracts that we acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as NPNS that we had previously recorded as "Derivative assets or liabilities." The initial amount recorded represents the fair value of the contract at the time of acquisition or designation, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. The amortization of these values is discussed in the *Revenues* and *Fuel and Purchased Energy Expenses* sections of this Note.

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our merchant energy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, daily monitoring of counterparty limits, employing credit mitigation measures such as margin, collateral (cash or letters of credit) or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, less any unrealized losses where we have a legally enforceable right of setoff.

Electric and gas utilities, municipalities, cooperatives, generation owners, coal producers, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling \$95.2 million as of December 31, 2009 and \$258.3 million as of December 31, 2008. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of our total credit exposure. As of December 31, 2009, we only had one significant counterparty concentration, CENG, which comprised 25% of our total credit exposure. This exposure is primarily related to the power purchase agreement that we executed with CENG which has a value of \$0.8 billion, which is recorded on our balance sheet in "Unamortized energy contract assets." However, no collection of counterparties based in a single country other than the United States comprised more than 10% of the total exposure of our total credit exposure.

Equity Investment Earnings

We include equity in earnings from our investments in qualifying facilities and power projects, joint ventures, and Constellation Energy Partners LLC (CEP) in "Equity Investment (Losses) Earnings" in our Consolidated Statements of Income (Loss) in the period they are earned. "Equity Investment (Losses) Earnings" also includes any adjustments to amortize the difference, if any, except for goodwill, between our cost in an equity method investment and our underlying equity in net assets of the investee at the date of investment.

We consider our investments in generation-related qualifying facilities, power projects, and joint ventures to be integral to our operations.

Taxes

We summarize our income taxes in *Note 10*. BGE and our other subsidiaries record their allocated share of our consolidated federal income tax liability using the percentage complementary method specified in U.S. income tax regulations. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

We have two categories of income tax expense—current and deferred. We describe each of these below:

- current income tax expense consists solely of regular tax less applicable tax credits, and
- deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to accumulated other comprehensive income. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described below) during the year.

Tax Credits

We defer the investment tax credits associated with our regulated business, assets previously held by our regulated business, and any investment tax credits that are convertible to cash grants in our Consolidated Balance Sheets. The investment tax credits are amortized evenly to income over the life of each property. We reduce current income tax expense in our Consolidated Statements of Income (Loss) for the investment tax credits that are not convertible to cash grants and other tax credits associated with our nonregulated businesses.

Through December 31, 2007, we held certain investments in facilities that manufactured solid synthetic fuel produced from coal as defined under the Internal Revenue Code for which we claimed tax credits on our Federal income tax return. Because the federal tax credit for synthetic fuel produced from coal expired on December 31, 2007, these facilities ceased fuel production on that date. We recognized the tax benefit of these credits in our Consolidated Statements of Income (Loss) when we believed it was highly probable that the credits will be sustained.

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than for income tax return purposes. The tax effects of the temporary differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in *Note 6*.

State and Local Taxes

State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income (Loss).

Taxes Other Than Income Taxes

Taxes other than income taxes primarily include property and gross receipts taxes along with franchise taxes and other non-income taxes, surcharges, and fees.

BGE and our Customer Supply operations collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer and others are imposed on BGE and our Customer Supply operations. Where these taxes, such as sales taxes, are imposed on the customer, we account for these taxes on a net basis with no impact to our Consolidated Statements of Income (Loss). However, where these taxes, such as gross receipts taxes or other surcharges or fees, are imposed on BGE or our Customer Supply operations, we account for these taxes on a gross basis. Accordingly, we recognize revenues for these taxes collected from customers along with an offsetting tax expense, which are both included in our Consolidated Statements of Income (Loss). The taxes, surcharges, or fees that are included in revenues were as follows:

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Constellation Energy (including BGE)	**$106.8**	$111.7	$113.4
BGE	**76.8**	73.2	77.0

Unrecognized Tax Benefits

We adopted guidance related to the accounting for uncertainty in income taxes on January 1, 2007.

We recognize in our financial statements the effects of uncertain tax positions if these positions meet a "more-likely-than-not" threshold. For those uncertain tax positions that we have recognized in our financial statements, we establish liabilities to reflect the portion of those positions we cannot conclude are "more-likely-than-not" to be realized upon ultimate settlement. These are referred to as liabilities for unrecognized tax benefits. We recognize interest and penalties related to unrecognized tax benefits in "Income tax expense" in our Consolidated Statements of Income (Loss).

We discuss our unrecognized tax benefits in more detail in *Note 10*.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing net income (loss) attributable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares primarily consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Non-dilutive stock options	**5.1**	2.6	—
Dilutive common stock equivalent shares	**1.0**	5.5	2.3

As a result of the Company incurring a loss for the year ended December 31, 2008, diluted common stock equivalent shares were not included in calculating diluted EPS.

We issued to MidAmerican Energy Holdings Company (MidAmerican) 19,897,322 shares of Constellation Energy's common stock upon the conversion of the Series A Preferred Stock, which occurred upon the termination of the merger agreement with MidAmerican on December 17, 2008. These additional shares impacted our earnings per share for 2009.

Stock-Based Compensation

Under our long-term incentive plans, we have granted stock options, performance-based units, service-based units, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss these awards in more detail in *Note 14*.

We recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments. We recognize compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption based on historical experience to estimate the number of awards that are expected to vest during the service period, and ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model and we remeasure the fair value of liability awards each reporting period. We do not capitalize any portion of our stock-based compensation.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Accounts Receivable and Allowance for Uncollectibles

Accounts receivable, which includes cash collateral posted in our margin account with third party brokers, are stated at the historical carrying amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on our expected exposure to the credit risk of customers based on a variety of factors.

Materials, Supplies, and Fuel Stocks

We record our fuel stocks, emissions credits, renewable energy credits, coal held for resale, and materials and supplies at the lower of cost or market. We determine cost using the average cost method for our entire inventory.

Restricted Cash

At December 31, 2009, our restricted cash primarily includes cash at one of our consolidated variable interest entities, proceeds from financing for the acquisition, construction, installation and equipping of certain sewage and solid waste disposal facilities at our Brandon Shores coal-fired generating plant in Maryland and BGE's funds restricted for the repayment of the rate stabilization bonds. At December 31, 2008, restricted cash also included the proceeds that we received on December 17, 2008 from issuance of the Series B Preferred Stock to EDF. These proceeds were restricted for payment of the 14% Senior Note that was held by MidAmerican. We used these proceeds to repay the 14% Senior Note in January 2009.

As of December 31, 2009 and 2008, BGE's restricted cash primarily represented funds restricted for the repayment of the rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Financial Investments

In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

We report our debt and equity securities at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses.

Available-for-Sale Securities

We classify our investments in trust assets securing certain executive benefits that are classified as available-for-sale securities.

We include any unrealized gains (losses) on our available-for-sale securities in "Accumulated other comprehensive loss" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

Long-Lived Assets

We evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. We test our long-lived assets and proved gas properties for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable.

We determine if long-lived assets and proved gas properties are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We record an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. Cash flows for long-lived assets are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Proven gas properties' cash flows are determined at the field level. Undiscounted expected future cash flows include risk-adjusted probable and possible reserves. We are also required to evaluate our equity-method and cost-method investments (for example, CENG and partnerships that own power projects) for impairment. The standard for determining whether an impairment must be recorded is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline.

We evaluate unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, legislative initiatives, and operating costs. However, actual future market prices and project costs could vary from those used in our impairment evaluations, and the impact of such variations could be material.

Investments

We evaluate our equity-method and cost-method investments (for example, CENG, UniStar Nuclear Energy, LLC (UNE), CEP and partnerships that own power projects) to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

Additionally, if the projects in which we hold these investments recognize an impairment, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity-method investments that own geothermal, coal, hydroelectric, fuel processing projects, as well as our equity investments in our nuclear joint ventures and CEP. These issues include environmental and legislative initiatives as well as events that will impact the viability of new nuclear development.

Debt and Equity Securities

We determine whether a decline in fair value of a debt or equity investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, we write-down the cost basis of the investment to fair value as a new cost basis.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We do not amortize goodwill. We evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. We amortize intangible assets with finite lives. We discuss the changes in our goodwill and intangible assets in more detail in *Note 5*.

Property, Plant and Equipment, Depreciation, Depletion, Amortization, and Accretion of Asset Retirement Obligations

We report our property, plant and equipment at its original cost, unless impaired.

Original cost includes:

- material and labor,
- contractor costs, and
- construction overhead costs, financing costs, and costs for asset retirement obligations (where applicable).

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the Conemaugh substation and transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $339.6 million at December 31, 2009 and $285.1 million at December 31, 2008. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income (Loss). Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $685.1 million at December 31, 2009 and $1,230.8 million at December 31, 2008.

When we retire or dispose of property, plant and equipment, we remove the asset's cost from our Consolidated Balance Sheets. We charge this cost to accumulated depreciation for assets that were depreciated under the group, straight-line method. This includes regulated property, plant and equipment and nonregulated generating assets. For all other assets, we remove the accumulated depreciation and amortization amounts from our Consolidated Balance Sheets and record any gain or loss in our Consolidated Statements of Income (Loss).

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income (Loss) as incurred.

Our oil and gas exploration and production activities consist of working interests in gas producing fields. We account for these activities under the successful efforts method of accounting. Acquisition, development, and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Depreciation and Depletion Expense

We compute depreciation for our generating, electric transmission and distribution, and gas distribution facilities. We compute depletion for our oil and gas exploitation and production activities. Depreciation and depletion are determined using the following methods:

- the group straight-line method using rates averaging approximately 2.3% per year for our generating assets,
- the group straight-line method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.2% per year for our regulated business, or
- the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Other assets are depreciated primarily using the straight-line method and the following estimated useful lives:

Asset	Estimated Useful Lives
Building and improvements	5 - 50 years
Office equipment and furniture	3 - 20 years
Transportation equipment	5 - 15 years
Computer software	3 - 10 years

Amortization Expense

Amortization is an accounting process of reducing an asset amount in our Consolidated Balance Sheets over a period of time that approximates the useful life of the related item. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income (Loss). We discuss the types of assets that we amortize and the periods over which we amortize them in more detail in *Note 5*.

Accretion Expense

We recognize an estimated liability for legal obligations and legal obligations conditional upon a future event associated with the retirement of tangible long-lived assets. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities.

Prior to November 6, 2009, substantially all of our total asset retirement obligation was associated with the decommissioning of our nuclear power plants—Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), Nine Mile Point Nuclear Station (Nine Mile Point) and R. E. Ginna Nuclear Power Plant (Ginna). Upon the close of the transaction with EDF on November 6, 2009, we deconsolidated CENG and removed the asset retirement obligations associated with these nuclear power plants from our Consolidated Balance Sheets. Our remaining asset retirement obligations are associated with our other generating facilities and certain other long-lived assets.

From time to time, we will perform studies to update our asset retirement obligations. We record a liability when we are able to reasonably estimate the fair value of any future legal obligations associated with retirement that have been incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets.

The increase in the capitalized cost is included in determining depreciation expense over the estimated useful lives of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income (Loss) until the settlement of the liability. We record a gain or loss when the liability is settled after retirement for any difference between the accrued liability and actual costs. The change in our "Asset retirement obligations" liability during 2009 was as follows:

	(In millions)
Liability at January 1, 2009	$ 987.3
Accretion expense	62.3
Liabilities incurred	0.2
Liabilities settled	(1.0)
Revisions to cash flows	5.8
Deconsolidation of CENG	(1,025.2)
Other	(0.1)
Liability at December 31, 2009	$ 29.3

Nuclear Fuel

Through November 6, 2009, we amortized the cost of nuclear fuel, including the quarterly fees we pay to the Department of Energy (DOE) for the future disposal of spent nuclear fuel, based on the energy produced over the life of the fuel. These fees were based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss).

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)
BGE finances its construction projects with borrowed funds and equity funds. BGE is allowed by the Maryland PSC and the FERC to record the costs of these funds as part of the cost of construction projects in its Consolidated Balance Sheets. BGE does this through the AFC, which it calculates using rates authorized by the Maryland PSC and the FERC. BGE bills its customers for the AFC plus a return after the utility property is placed in service.

The AFC rates are 9.4% for electric distribution plant, 8.8% for electric transmission plant, 8.5% for gas plant, and 9.1% for common plant. BGE compounds AFC annually.

Long-Term Debt and Credit Facilities
We defer all costs related to the issuance of long-term debt and credit facilities. These costs include underwriters' commissions, discounts or premiums, other costs such as external legal, accounting, and regulatory fees, and printing costs. We amortize costs related to long-term debt into interest expense over the life of the debt. We amortize costs related to credit facilities to other income (expense) over the terms of the facilities.

In addition to the fees that are paid upfront for credit facilities, we also incur ongoing fees related to these facilities. We record the ongoing fees in other income (expense), and we record interest incurred on cash draws in interest expense.

When BGE incurs gains or losses on debt that it retires prior to maturity, it amortizes those gains or losses over the remaining original life of the debt in accordance with regulatory requirements.

Accounting Standards Issued
Accounting for Variable Interest Entities
In June 2009, the FASB amended the accounting, presentation, and disclosure guidance related to variable interest entities, effective for interim and annual reporting periods beginning after November 15, 2009. The amended standard includes the following significant provisions:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We are completing our evaluation of this standard. Based on our evaluation to date, we believe the primary impact will be increased VIE disclosures, and we do not believe the implementation of this standard will have a material impact on our, or BGE's, financial results.

Accounting Standards Adopted
Noncontrolling Interests in Consolidated Financial Statements
In December 2007, the FASB issued amended guidance related to the accounting and reporting of noncontrolling interests in consolidated financial statements. A noncontrolling interest in a subsidiary is now considered an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This presentation views the consolidated business as a single economic entity and considers minority ownership interests in consolidated subsidiaries as equity in the consolidated entity.

Under the amended guidance, companies are required to:

- present noncontrolling interests (formerly described as "minority interests") in the consolidated balance sheet as a separate line item within equity,
- separately present on the face of the income statement the amount of consolidated net income attributable to the parent and to the noncontrolling interest,
- account for changes in ownership interests that do not result in a change in control as equity transactions, and
- upon deconsolidation of a subsidiary due to a change in control, measure any retained interest at fair value and record a gain or loss for both the portion sold and the portion retained.

Effective January 1, 2009, we presented and disclosed noncontrolling interests in our Consolidated Financial Statements in accordance with the amended guidance, and we accounted for the sale of a 49.99% membership interest in CENG to EDF by deconsolidating CENG, measuring our retained interest at fair value, and recognizing a gain at closing. We discuss this transaction in more detail in *Note 2*.

Disclosures about Derivative Instruments and Hedging Activities
In March 2008, the FASB issued amended guidance requiring significantly expanded disclosures about derivative instruments and hedging activities, but did not change the accounting for derivatives. We adopted the new disclosure requirements on January 1, 2009 and provide these additional disclosures in *Note 13*.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions That Are Not Orderly
In April 2009, the FASB issued accounting guidance for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and for identifying transactions that are not orderly. The guidance provides for estimating fair value when the volume and level of activity for the asset or liability have decreased and assists in identifying circumstances that indicate a transaction is not orderly. Finally, the guidance expands the disclosure requirements for fair value measurements to include further disaggregation in the tabular disclosures. We adopted this guidance as of April 1, 2009 with no effect on our, or BGE's, financial results and provided the required disclosures about fair value measurements in *Note 13*. The adoption of this standard only impacted our disclosures.

2 Other Events

2009 Events

	Pre-Tax	After-Tax
	(In millions)	
Gain on sale of 49.99% membership interest in our nuclear generation and operation business (CENG) to EDF	**$7,445.6**	**$4,456.1**
Amortization of basis difference in CENG	**(29.6)**	**(17.8)**
Net loss on divestitures	**(468.8)**	**(293.2)**
Impairment losses and other costs (1)	**(124.7)**	**(96.2)**
Impairment of nuclear decommissioning trust assets through November 6, 2009	**(62.6)**	**(46.8)**
Loss on redemption of Zero Coupon Senior Notes	**(16.0)**	**(10.0)**
Maryland PSC order—BGE residential customer credits	**(112.4)**	**(67.1)**
Merger termination and strategic alternatives costs	**(145.8)**	**(13.8)**
Workforce reduction costs	**(12.6)**	**(9.3)**
Total other items	**$6,473.1**	**$3,901.9**

(1) After-tax amount net of noncontrolling interest.

Gain on Sale of 49.99% Membership Interest in CENG to EDF
On December 17, 2008, we entered into an Investment Agreement with EDF under which EDF would purchase from us a 49.99% membership interest in CENG for $4.5 billion (subject to certain adjustments).

In October 2009, the Maryland PSC issued an order approving our transaction with EDF subject to the following conditions:

- Constellation Energy is to fund a one-time per customer distribution rate credit for BGE residential customers, before the end of March 2010, totaling $110.5 million, or approximately $100 per customer, for which we recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating we would give residential customers a rate credit of exactly $100 per customer. As a result, we accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. Constellation made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.
- Constellation Energy is required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. We made this contribution in December 2009.
- BGE will not pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.
- BGE may file an electric distribution rate case at any time beginning in January 2010 and may not file a subsequent electric distribution rate case until January 2011. Any rate increase in the first electric distribution rate case will be capped at 5% as agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. The timing of any gas distribution rate filing will also occur no earlier than the electric case.
- Constellation Energy will be limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.
- Constellation Energy and BGE are required to implement "ring fencing" measures designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy (RF HoldCo) to hold all of the common equity interests in BGE. We completed the implementation of these measures in February 2010.

With the receipt of the Maryland PSC's order, Constellation Energy and EDF closed the transaction on November 6, 2009. Upon closing of the transaction, we sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

We recorded this transaction as follows:

- We received cash consideration of approximately $3.5 billion, plus certain adjustments, and redeemed the $1.0 billion Series B Preferred Stock held by EDF as additional purchase price resulting in net proceeds of approximately $4.7 billion.
- We removed the individual assets and liabilities of CENG from our balance sheet with a net asset value of approximately $2.4 billion.
- We recorded our retained investment in CENG at estimated fair value of approximately $5.1 billion.

- We recognized a pre-tax gain on sale of approximately $7.4 billion, calculated as follows:

	(In billions)
Fair value of the consideration received from EDF	$ 4.7
Estimated fair value of our retained interest in CENG	5.1
Carrying amount of CENG's assets and liabilities prior to deconsolidation	(2.4)
Pre-tax gain	$ 7.4

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in the merchant energy segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We estimated the fair value of CENG for purposes of recording our retained interest upon closing of the sale. Our estimate considered the replacement cost, discounted future cash flows, and comparable market transactions valuation approaches. After correlating the valuations under these three approaches, the ultimate fair value estimate reflects the discounted future expected cash flows of the business using various inputs that we believe are reflective of a market participant's perspective. The most significant inputs include our expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments, and a discounting factor reflective of an investor's required risk-adjusted return.

The fair value of our investment in CENG exceeded our share of CENG's equity because CENG's assets and liabilities retained their historical carrying value. This basis difference totaled approximately $3.9 billion, and we assigned it to the noncurrent assets of CENG based on fair value. We will amortize this difference as a reduction in our equity investment earnings in CENG as follows:

Difference	**Amortization Period**
Property, plant and equipment	Depreciable life
Power purchase agreements and revenue sharing agreements	Term of the agreement
Land and intangibles with indefinite lives	Upon sale by CENG

For the period November 6, 2009 through December 31, 2009, we recorded $29.6 million of basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Also, if we were to sell an additional portion of our investment, we would recognize a proportionate amount of the basis difference.

Divestitures

In 2009, we completed many of the strategic initiatives we identified in 2008 to improve liquidity and reduce our business risk.

The transactions to sell a majority of our international commodities, our Houston-based gas trading and other operations were structured in two parts:

- the assignment and transfer of a majority of the portfolio, and
- the execution of a Total Return Swap (TRS) mechanism for the remainder of the portfolio.

Under the TRS, we entered into offsetting trades with the buyers that matched the terms of the remaining third party contracts for which we were unable to complete assignment to the buyers as of the transaction dates. This structure transferred the risks associated with changes in commodity prices as of the transaction dates to the buyers in all instances. However, the trades under the TRS are newly executed transactions, and we remain the principal under both the unassigned third party trades and the matching trades with the buyers under the TRS with no right of either financial or legal offset. We continue to pursue the assignment of these remaining contracts to the buyers.

The matching contracts under the TRS include both derivatives and non-derivatives and were executed at prices that differed from market prices at closing, which resulted in a net cash payment to/from the buyers. We recorded the underlying contracts at fair value on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether the contract prices were above- or below-market prices at closing. As a result, the derivative contracts have been included in "Derivative Assets and Liabilities" and the nonderivative contracts have been included in "Unamortized Energy Contract Assets and Liabilities." The derivative contracts are subject to mark-to-market accounting until they are realized or assigned. The nonderivative contracts will be amortized into earnings as the underlying contracts are realized, or sooner if those contracts are assigned.

We record the cash proceeds we pay or receive at the inception of energy purchase and sale contracts based upon whether the contracts are in-the-money or out-of-the-money as follows:

In-the-money contracts—proceeds paid	Investing Outflow
Out-of-the-money contracts—proceeds received	Financing Inflow

After inception, we record the cash flows from all energy purchase and sale contracts as operating activities, except for out-of-the-money derivative contracts that were liabilities at inception. We record the ongoing cash flows from these out-of-the-money derivative contracts as financing activities, regardless of whether they are purchase or sale contracts.

International Commodities Operation
In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. We completed this transaction on March 23, 2009 and recognized the following impacts during 2009:

- a pre-tax loss of approximately $334.5 million representing net consideration paid to the buyer, the book value of net assets sold, and transaction costs,
- a reclassification of $165.7 million in losses on previously designated cash-flow hedge contracts, for which the forecasted transactions are now deemed probable of not occurring, from "Accumulated Other Comprehensive Loss" to "Nonregulated revenues" in the Consolidated Statements of Income (Loss),
- workforce reduction costs of $10.9 million, recorded as part of "Workforce reduction costs" in the Consolidated Statements of Income (Loss), and
- other costs of $17.6 million related to leasehold improvements, furniture and computer hardware and software, recorded as part of "Impairment losses and other costs" in the Consolidated Statements of Income (Loss).

We removed the contracts that were assigned from our balance sheet, paid the buyer approximately $90 million, and reflected the impact of this payment on our working capital in the operating activities section of our Consolidated Statements of Cash Flows.

The net cash payment to the buyer upon completion of the TRS was $2.5 million. As part of the consideration, we acquired matching nonderivative contracts that resulted in a net liability of approximately $75 million, which will be amortized into earnings as the underlying contracts are realized, or sooner if the original nonderivative contracts are assigned.

We have reflected the contracts under the TRS on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009	*(In millions)*
Investing activities—Contract and portfolio acquisitions	**$(866.3)**
Financing activities—Proceeds from contract and portfolio acquisitions	**863.8**
Net cash flows from contract and portfolio acquisitions	**$ (2.5)**

In addition to the March 23, 2009 transaction for a majority of our international commodities operation, on June 30, 2009 we completed the sale of a uranium market participant that we owned. We received cash proceeds of approximately $43 million and recorded a $27.2 million loss on this sale. This loss from our merchant energy segment is included in the "Net (loss) gain on divestitures" line in our Consolidated Statements of Income (Loss).

Houston-Based Gas and Other Trading Operations
On February 3, 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. We transferred control of this operation on April 1, 2009. In addition, in the second quarter of 2009 we also sold certain other trading operations. In total, we received proceeds of approximately $61 million, and recorded a $102.5 million net loss on these sales in 2009. The net loss on sale primarily relates to nonderivative accrual contracts, which were not recorded on our Consolidated Balance Sheet, the cost associated with disposing of an entire portfolio and not merely individual contracts, and the cost of capital, including contingent capital, to support the operation.

The matching derivative and nonderivative transactions under the TRS discussed above were executed at prices that differed from market prices at closing. As a result, we record the ongoing cash flows related to the out-of-the-money derivative contracts that were liabilities at inception as financing cash flows. This resulted in cash outflows related to financing activities of $858.5 million in our Consolidated Statements of Cash Flows for the year ended December 31, 2009 associated with derivative liabilities that were out-of-the-money.

The net cash receipt from the buyers upon completion of the TRS was $91.9 million in the second quarter of 2009. We have reflected these contracts on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009	*(In millions)*
Investing activities—Contract and portfolio acquisitions	**$(1,287.4)**
Financing activities—Proceeds from contract and portfolio acquisitions	**1,379.3**
Net cash flows from contract and portfolio acquisitions	**$ 91.9**

In addition, we incurred other costs of $7.0 million for 2009 related to leasehold improvements, furniture, computer hardware and software costs, which are recorded as part of "Impairment losses and other costs" on our Consolidated Statements of Income (Loss).

On April 1, 2009, we executed an agreement with the buyer of our Houston-based gas trading operation under which the buyer will provide us with the gas supply needed to support our retail gas customer supply business through March 31, 2011. This agreement was structured such that our requirements to post collateral are reduced. The supplier has liens on the assets of the retail gas supply business as well as our investment in the stock of these entities to secure our obligations under the gas supply agreement. In connection with this agreement, we posted approximately $160 million of collateral. This was subsequently reduced to $100 million. The initial $160 million posted represented approximately 25 percent of the previous collateral requirements to support this operation.

Shipping Joint Venture
We completed the sale of our equity investment in a shipping joint venture during the third quarter of 2009. No gain or loss was recognized on the sale. We discuss the sale of the shipping joint venture below.

Other Nonregulated Divestiture
During the fourth quarter of 2009, one of our nonregulated subsidiaries sold an energy project and recorded a net loss of $4.6 million.

Impairment Losses and Other Costs
Available for Sale Securities
We evaluated certain of our investments in equity securities during 2009. The investments we evaluated included our nuclear decommissioning trust fund assets (through November 6, 2009) and other marketable securities. We record an impairment charge if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary."

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and duration of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value is considered other than temporary and we write them down to fair value. We discuss our impairment policy in more detail in *Note 1*.

The fair values of certain of the securities held in our nuclear decommissioning trust fund held through November 6, 2009 and other marketable securities declined below book value. As a result, we recorded a $62.6 million pre-tax impairment charge for the year ended December 31, 2009 for our nuclear decommissioning trust fund assets in the "Other income (expense)" line in our Consolidated Statements of Income (Loss). We also recorded an impairment charge of $0.5 million for other marketable securities not included in our nuclear decommissioning trust funds for the year ended December 31, 2009.

The estimates we utilize in evaluating impairment of our available for sale securities require judgment and the evaluation of economic and other factors that are subject to variation, and the impact of such variations could be material.

Equity Method Investments
Shipping Joint Venture
We record an impairment if an equity method investment has experienced a decline in fair value to a level less than our carrying value and the decline is other than temporary. During the quarter ended June 30, 2009, we contemplated several potential courses of action together with our partner relating to the strategic direction of our shipping joint venture and our continuing involvement. This led to a decision to explore a plan to sell our 50% interest to a party related to our joint venture partner for negligible proceeds. We completed the sale of this investment in the third quarter of 2009. We have no further involvement in the activities of the joint venture.

As a result of the events that occurred during the second quarter of 2009, we concluded that the fair value of our investment had declined to a level below the carrying value at June 30, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $59.0 million associated with our equity investment in our shipping joint venture within the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and reported the charge in our merchant energy business results for 2009.

Constellation Energy Partners LLC
As of March 31, 2009, the fair value of our investment in Constellation Energy Partners LLC (CEP) based upon its closing unit price was $10.0 million, which was lower than its carrying value of $24.0 million.

The decline in fair value of our investment in CEP reflected a number of other factors, including:
- continuing difficulties in the financial and credit markets in the United States,
- decreases in the market price of natural gas and oil,
- the effect of these factors on market perceptions of gas exploration and production master limited partnerships, and
- factors related to Constellation Energy's financial condition and possible sale of its investment in CEP.

As a result of evaluating these factors, we determined that the decline in the value of our investment is other than temporary. Therefore, we recorded a $14.0 million pre-tax impairment charge at March 31, 2009 to write-down our investment to fair value. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). We did not record an impairment charge for the remainder of 2009.

District Chilled Water
During 2009, BGE entered into an agreement to sell its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. We completed this sale in January 2010. We have no further involvement in the activities of this entity.

As a result of these events, we concluded that the fair value of our investment in this subsidiary had declined to a level below carrying value at December 31, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $12.0 million, net of the noncontrolling interest impact of $8.0 million. The gross impairment charge of $20.0 million is recorded within the "Impairment losses and other costs" line in both our and BGE's Consolidated Statements of Income (Loss). The noncontrolling interest portion of $8.0 million is recorded within the "Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends" line in our Consolidated Statements of Income (Loss) and within the "Net Income Attributable to Noncontrolling Interests" line in BGE's Consolidated Statements of Income.

Other Costs

During 2009, we recorded $31.2 million pre-tax charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss) primarily related to:

- divested operations—long-lived assets no longer used and lease terminations, and
- the write-off of an uncollectible advance to an affiliate.

Loss on Redemption of Zero Coupon Senior Notes

In November 2009, we redeemed the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Merger Termination and Strategic Alternatives Costs

We incurred additional costs during 2009 related to the terminated merger agreement with MidAmerican, the transactions related to EDF, and other strategic alternatives costs. These costs totaled $145.8 million pre-tax for the year ended December 31, 2009, and primarily relate to fees incurred to complete the transactions with EDF and the first quarter of 2009 write-off of the unamortized debt discount associated with the 14% Senior Notes (Senior Notes) that were repaid in full to MidAmerican in January 2009. Upon the closing of the transaction with EDF on November 6, 2009, certain of the costs incurred in 2008 and 2009 became tax deductible. We reflected this impact in 2009.

Workforce Reduction Costs

We incurred workforce reduction costs during the fourth quarter of 2008, primarily related to workforce reduction efforts across all of our operations (Q4 2008 Program), and during the first quarter of 2009, primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization (Q1 2009 Program). For the Q1 2009 Program, we recognized a $12.6 million pre-tax charge during 2009 related to the elimination of approximately 180 positions. We expect both of these restructurings will be completed by the end of the first quarter of 2010.

The following table summarizes the status of the involuntary severance liabilities at December 31, 2009:

	Q1 2009 Program	Q4 2008 Program
	(In millions)	
Initial severance liability balance	$ 10.8	$ 19.7
Additional expenses recorded in 2009	1.8	—
Amounts recorded as pension and postretirement liabilities	—	(3.0)
Net cash severance liability	12.6	16.7
Cash severance payments	(12.0)	(15.8)
Severance liability balance at December 31, 2009	$ 0.6	$ 0.9

2008 Events

	Pre-Tax	After-Tax
	(In millions)	
Merger termination and strategic alternatives costs	**$(1,204.4)**	**$(1,204.4)**
Impairment losses and other costs	**(741.8)**	**(470.7)**
Workforce reduction costs	**(22.2)**	**(13.4)**
Emissions allowances write-down	**(46.7)**	**(28.7)**
Net gain on divestitures	**25.5**	**16.0**
Gain on sale of dry bulk vessel	**29.0**	**18.9**
Maryland settlement credit (after-tax amount reflects the effective tax rate impact on BGE)	**(189.1)**	**(110.5)**
Impairment of nuclear decommissioning trust assets	**(165.0)**	**(82.0)**
Total other items	**$(2,314.7)**	**$(1,874.8)**

Merger Termination and Strategic Alternatives Costs

We incurred costs during 2008 related to the terminated merger agreement with MidAmerican, the conversion of Series A Preferred Stock, the execution of the Investment Agreement and related agreements with EDF, and our pursuit of other strategic alternatives. These costs totaled $1.2 billion pre-tax. We did not record a tax benefit for any of these costs in our Consolidated Statement of Income (Loss) in 2008.

A significant portion of these costs was incurred pursuant to the termination of the merger agreement with MidAmerican and the conversion of the Series A Preferred Stock. Specifically, Constellation Energy incurred the following charges:

- $175 million merger termination fee,
- approximately $945 million for settling the conversion of the Series A Preferred Stock, which included a cash payment of $418 million and issuance of approximately 19.9 million shares of our common stock,

- approximately $15 million for the remaining unamortized portion of the premium paid as part of executing an agreement with MidAmerican in November 2008 that provided us the option to sell certain generating plants to MidAmerican for aggregate proceeds of $350 million. This agreement was terminated as part of the termination of our merger agreement with MidAmerican, and
- approximately $70 million in other costs associated with the MidAmerican transaction and other strategic alternatives explored consisting primarily of external legal, accounting and consulting fees.

The above amounts do not include $150 million of cash received from EDF in conjunction with the Investment Agreement entered into on December 17, 2008. We recorded this $150 million as additional purchase price at closing.

BGE recorded $16 million as its allocable portion of these costs through November 30, 2008 when the merger with MidAmerican was still pending. However, in light of the EDF transaction involving an investment in our nonregulated nuclear generation and operation business rather than a merger with Constellation Energy, BGE was not allocated any further costs effective in December 2008 and all of the previously allocated costs recorded by BGE were allocated to the merchant energy segment.

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method investments, and goodwill when triggering events occur that would indicate that the potential for an impairment exists. We perform an impairment evaluation for our nuclear decommissioning trust fund assets quarterly.

In addition, we evaluate goodwill for impairment on an annual basis regardless of whether any triggering events have occurred. Our accounting policy is to perform an annual goodwill impairment review in the third quarter of each year.

During the third quarter of 2008, the following triggering events resulted in the need for us to perform impairment analyses:

- we announced a strategic initiative to sell our upstream gas assets subject to market conditions,
- there was a significant decline in the availability of credit in the markets,
- there was a significant decline in the overall stock market and, in particular, our stock price,
- we signed a definitive merger agreement with MidAmerican, which was subsequently terminated, and
- commodity prices declined substantially.

As a result of these evaluations, we recorded impairments of our upstream gas properties, goodwill, and certain investments in debt and equity securities. Additionally, in the fourth quarter of 2008, there were continued declines in commodity prices and the overall stock market. This led to further impairment of our upstream gas properties, and certain investments in debt and equity securities. We describe the impairment evaluations we performed in the following sections.

Long-Lived Assets

We evaluate potential impairment of long-lived assets classified as held for use and recognize an impairment loss if the carrying amount of such assets is not recoverable. The carrying amount of an asset held for use is not recoverable if it exceeds the total undiscounted future cash flows expected to result from the use and eventual disposition of the asset.

This evaluation requires us to estimate uncertain future cash flows. In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. The assumptions we use are consistent with forecasts that we make for other purposes (for example, in preparing our other earnings forecasts) or have been adjusted to reflect relevant subsequent changes. If we are considering alternative courses of action (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the expected cash flows.

We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

Upstream Gas Properties

During 2008, we performed impairment analyses for our upstream gas properties as a result of the following triggering events:

- we announced our intent to sell our upstream gas assets, and
- there were significant decreases in natural gas prices and oil prices in both the third and fourth quarters of 2008.

We evaluated both proved and unproved property for impairments. Unproved property is impaired if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance. To the extent that unproved property is part of an asset that contains proved property, we applied the accounting guidance for proved property for evaluating impairment.

During the third quarter of 2008, we began the process necessary to sell our upstream gas properties, and, while we sold some of these properties by December 31, 2008, we had not yet obtained the formal approval of our Board of Directors for the sale of our other remaining properties. This approval was required to commit to a plan for sale. As a result, we continued to classify these properties as held for use as of December 31, 2008. Accordingly, our impairment evaluation consisted of estimating expected undiscounted cash flows under various scenarios as discussed below and comparing those amounts to the carrying value.

We evaluated our upstream gas portfolio for impairment at the individual property level, which is the lowest level of identifiable cash flows, since each property has separate financial statements identifying and capturing the related cash flows. We evaluated a combination of cash flows from operations scenarios for the remaining period for which we expected to hold these properties as well as estimates of proceeds from each property's ultimate disposal. The primary inputs to our estimates of cash flows from operations were reserve estimates and natural gas and oil prices based upon forward curves and modeled data for unobservable periods. The primary inputs to our estimate of proceeds from disposal were a combination of external market bids, internal models and reserve reports, and information from external advisors assisting in the sale of these assets. We maximized the use of market information to the extent it was available. We evaluated several possible courses of action and timing, and we probability-weighted the cash flows associated with each of these scenarios based upon our best estimates of the expected outcome and timing in order to arrive at each property's expected future cash flows.

Our evaluation indicated that estimated cash flows were less than the carrying value of three of our seven upstream gas properties at September 30, 2008. At December 31, 2008, our evaluation indicated that estimated cash flows were less than the carrying value for two additional properties and for one property in which that property's estimated cash flows were less than its post-impairment carrying value at September 30, 2008 as well. The primary factors leading to the declines in expected cash flows were the decrease in market prices for natural gas and oil during the third and fourth quarters of 2008 combined with our expectation that we would sell these properties rather than hold them for their full useful lives.

As a result, we recorded the following pre-tax impairment charges:

Asset Groups	At September 30, 2008	At December 31, 2008
	(In millions)	
Interest in proved and unproved natural gas and crude oil reserves in south Texas	**$ 62.6**	**$ —**
Interest in proved natural gas reserves in the Rocky Mountains	**73.2**	**—**
Interest in proved and unproved natural gas reserves in the Offshore-Gulf of Mexico	**7.1**	**3.8**
Interest in proved and unproved crude oil and natural gas reserves in eastern Oklahoma	**—**	**30.0**
Interest in proved and unproved natural gas reserves in central Oklahoma	**—**	**153.2**
Total impairment charges	**$142.9**	**$187.0**

We recorded these impairment charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and they are reported in our merchant energy business results.

Generating Plants

We evaluated the impact of the events that occurred in 2008 on the recoverability of our generating plants. Based upon our consideration of these events and the status of the generating plant's activities, we determined that our generating plants were not impaired as of September 30, 2008 and December 31, 2008.

Debt and Equity Securities and Investments

We evaluated certain of our investments in debt and equity securities (both equity-method and cost-method investments) in light of declines in market prices during the third and fourth quarters of 2008. The investments we evaluated included our investment in CEP, other marketable securities, our nuclear decommissioning trust fund assets, and our investment in UNE. We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is other than temporary. We do not record an impairment if the decline in value is temporary and we have the ability and intent to hold the investment until its value recovers.

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and length of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value for these securities is considered other than temporary and we write them down to fair value.

The fair value of our investment in CEP fell below carrying value at the end of August, and continued to decline through the end of 2008. As of September 30, 2008, the fair value of our investment in CEP based upon its closing unit price was $73 million, which was lower than its carrying value of $128 million. As of December 31, 2008, the fair value of our investment in CEP based upon its closing unit price was $17 million, which was lower than its carrying value at December 31, 2008 of $87 million.

While CEP's estimate of net asset value exceeded our carrying value, the decline in fair value of our investment in CEP reflects a number of other factors, including:

- turmoil and tightening in the financial and credit markets in the United States,
- substantial decreases in the market price of natural gas and oil,
- the effect of these factors on market perceptions of gas exploration and production master limited partnerships, and
- factors related to Constellation Energy's financial condition and possible sale of its investment in CEP.

As a result of evaluating these factors at both September 30, 2008 and December 31, 2008, we determined that the declines in the value of our investment at both dates were other than temporary. Therefore, we recorded a $54.7 million pre-tax impairment charge at September 30, 2008 and an additional $69.7 million pre-tax impairment charge at December 31, 2008 to write-down our investment to fair value. We recorded these charges in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the market price of our investment declines further in future quarters, we may record additional write-downs if we determine that those additional declines are other than temporary.

As a result of significant declines in the stock market during 2008, the fair values of certain of our marketable securities and many of the securities held in our nuclear decommissioning trust fund declined below book value. As a result, we recorded impairment charges of $31.0 million and $122.0 million pre-tax at September 30, 2008 and December 31, 2008, respectively, for our nuclear decommissioning trust fund investments in the "Other (expense) income" line in our Consolidated Statements of Income (Loss). We had previously recorded impairment charges for our nuclear decommissioning trust fund at both March 31, 2008 and June 30, 2008, totaling $12.0 million pre-tax. We also recorded an impairment charge of $7.0 million pre-tax for certain of our other marketable securities in the fourth quarter of 2008. In addition, we recorded other changes in the fair value of our nuclear decommissioning trust fund assets that are not impaired in other comprehensive income. We discuss the assets within our nuclear decommissioning trust funds in more detail in *Note 4*.

We also evaluated the impact of the events that occurred in 2008 on the recoverability of our investment in UNE. Based upon our consideration of these events and the status of UNE's activities, we determined that our investment in UNE was not impaired as of December 31, 2008.

The estimates we utilize in evaluating impairment of our debt and equity securities require judgment and the evaluation of economic and other factors that are subject to variation, and the impact of such variations could be material.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, in the third quarter of each year, we evaluate goodwill for impairment.

The primary judgment affecting our impairment evaluation is the requirement to estimate fair value of the reporting units to which the goodwill relates. We evaluate impairment at the reportable segment level, which is the lowest level in the organization that constitutes a business for which discreet financial information is available.

Prior to September 30, 2008, substantially all of our goodwill related to our merchant energy segment. The lack of observable market prices for the merchant energy segment required us to estimate fair value, which we determined on a preliminary basis using the income valuation approach by computing discounted cash flows, consistent with prior evaluations. Although our estimate of discounted cash flows exceeded the carrying value of the merchant energy segment, because our common stock continued to trade at a price less than carrying value for the entire company throughout the last half of September and all of October, we also estimated fair value for the merchant energy segment using current market price information.

The primary inputs and assumptions to our estimate of fair value based upon market information were as follows:

- the fair value of Constellation Energy based upon recent market prices of our common stock,
- the estimated fair value of BGE, and
- the estimated value of the agreements executed with MidAmerican.

Using this information, we deducted the estimated fair value of non-merchant energy segment businesses from the fair value of Constellation Energy as a whole in order to estimate the fair value of the merchant energy segment as of September 2008. Based upon this estimate, the fair value of the merchant energy segment was substantially less than its carrying value. The primary difference between this estimate and our modeled estimates using the discounted cash flow income approach is that the market price approach incorporated the market's valuation discount associated with our merchant energy segment due to its significant liquidity and collateral requirements. We believe that this was a more appropriate method for estimating fair value than the modeled valuation techniques because it incorporated observable market information to a greater extent, which reflects current market conditions, and because it required fewer and less subjective judgments and estimates than our modeled estimates.

As a final consideration during our September 2008 impairment evaluation, we also evaluated the circumstances surrounding MidAmerican's purchase of Constellation Energy and whether the current market price of our common stock should be considered to represent fair value for accounting purposes. While the transaction price for the purchase of Constellation Energy resulted from negotiations that occurred over an abbreviated period of time during which the Company was experiencing financial difficulty, ongoing trading of the stock at levels approximating the transaction price represented the market's present assessment of fair value in a liquid, active market. This is consistent with guidance issued by the Securities Exchange Commission Office of the Chief Accountant and FASB Staff on the determination of fair value in distressed markets.

Based on our evaluation of these alternative measures of fair value, we determined that the fair value of the merchant energy business segment was less than its carrying value. Therefore, in order to measure the potential impairment of goodwill, we estimated the fair value of the merchant energy segment's assets and liabilities. We determined that the fair value of its assets net of liabilities substantially exceeded the segment's total fair value, indicating that the merchant energy segment's goodwill was impaired as of September 30, 2008. Accordingly, we recorded a pre-tax charge of $266.5 million to write-off the entire balance of our merchant energy segment goodwill substantially all of which was recorded in the third quarter of 2008. This charge is recorded in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Other Costs
In September 2008, we entered into a non-binding agreement to settle a class action complaint that alleged a subsidiary's ash placement operations at a third party site damaged surrounding properties. In December 2008, the settlement was approved by the court. As a result of this agreement, we recorded a $14.0 million pre-tax charge net of an expected insurance recovery.

Workforce Reduction Costs
We incurred costs related to workforce reduction efforts initiated at our nuclear generating facilities in 2006 and 2007. We substantially completed both of these workforce reduction efforts during 2008.

In September 2008, our merchant energy business approved a restructuring of the workforce at our Customer Supply operations. We recognized a $2.5 million pre-tax charge during 2008 related to the elimination of approximately 100 positions associated with this restructuring. We substantially completed this workforce reduction during 2009.

During the fourth quarter of 2008, we approved a restructuring of the workforce across all of our operations. We recognized a $19.7 million pre-tax charge in 2008 related to the elimination of approximately 380 positions.

Emissions Allowances
The Clean Air Interstate Rule (CAIR) required states in the eastern United States to reduce emissions of sulfur dioxide (SO_2) and established a cap-and-trade program for annual nitrogen oxide (NO_x) emission allowances. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit (the "Court") issued an opinion vacating CAIR, subject to petitions for rehearing. The Environmental Protection Agency (EPA) filed a petition for rehearing. On December 23, 2008, the Court reversed its earlier decision to revoke CAIR and will allow CAIR to remain in effect until it is replaced by a revised rule issued by the EPA that would preserve the environmental rules established by CAIR. The Court did not propose a deadline by which the EPA must correct the flaws identified with CAIR but it did state that it will accept petitions if the EPA does not remedy the problems previously identified in its July 11, 2008 opinion.

As a result of the Court's December 2008 decision, the annual NO_x program became effective in 2009 as originally established by CAIR. In addition, since the December 2008 decision, market prices for 2009 NO_x allowances have increased significantly, with lesser increases shown in allowances for subsequent years. There was also an increase in trading volumes for annual NO_x. For the SO_2 program, the EPA will be required to issue a new rule that would replace the allowances issued under Title IV of the Clean Air Act with a new, reduced pool of allowances which would meet or exceed existing CAIR targets. Market prices for SO_2 allowances have also risen since the Court's decision.

We account for our emission allowance inventory at the lower of cost or market, which includes consideration of our expected requirements related to the future generation of electricity. The weighted-average cost of our 2008 SO_2 allowance inventory in excess of amounts needed to satisfy these requirements was greater than market value at June 30, 2008 and market prices decreased further for both SO_2 and annual NO_x emission allowances through September 30, 2008. After giving consideration to the Court's July 11, 2008 decision and the subsequent decline in the market price of these allowances, we recorded a write-down of our SO_2 allowance inventory totaling $22.1 million pre-tax to reflect the June 30, 2008 market prices. At September 30, 2008, we recorded an additional write-down of our SO_2 emission allowance inventory and recorded a write-down of our annual NO_x allowance inventory totaling $58.9 million to reflect the September 30, 2008 prices. These write-downs were recorded in the "Nonregulated revenues" line in our Consolidated Statements of Income (Loss). The third quarter 2008 write-down was partially offset by mark-to-market gains totaling $22.2 million pre-tax on derivative contracts for the forward sale of emission allowances. This gain reflects the impact of lower market prices on the value of those derivative contracts.

Due to the increases in SO_2 and NO_x emission allowance prices stemming from the December 23, 2008 Court ruling, we evaluated the value of our emissions allowances and determined that a partial reversal of prior interim period write-downs was appropriate. At December 31, 2008, we reversed $11.4 million of the second and third quarter of 2008 write-downs. The prices at December 31, 2008 create a new cost basis for SO_2 and annual NO_x emission allowances and cannot be further written-up in future periods. Our mark-to-market gains on derivative contracts for the forward sale of emission allowances were $0.7 million for the quarter ended December 31, 2008. We cannot predict the outcome of any further judicial, regulatory or legislative developments or their impact on the emission allowance markets.

Net Gain on Divestitures
On March 31, 2008, we sold our working interest in oil and natural gas producing properties in Oklahoma to CEP, a related party, and recognized a gain of $14.3 million, net of the minority interest gain of $0.7 million. We discuss this transaction in more detail in *Note 16*.

In addition, on June 30, 2008, our merchant energy business sold a portion of its working interests in proved natural gas reserves and unproved properties in Arkansas to an unrelated party for total proceeds of $145.4 million, which is subject to certain purchase price adjustments. Our merchant energy business recognized a $77.7 million pre-tax gain on this sale.

In December 2008, our merchant energy business sold working interests in proved natural gas reserves in Wyoming, and our equity investment in certain entities that own interests in proved natural gas reserves and unproved properties in Texas and Montana to unrelated parties for total proceeds of $55.7 million, subject to certain purchase price adjustments. Our merchant energy business recognized a $67.2 million pre-tax loss on these sales.

The net gain is included in "Net (Loss) Gains on Divestitures" line in our Consolidated Statements of Income (Loss).

Gain on Sale of Dry Bulk Vessel
On July 10, 2008, a shipping joint venture, in which our merchant energy business has a 50% ownership interest, sold one of the six dry bulk vessels it owns. Our merchant energy business recognized a $29.0 million pre-tax gain on this sale. The gain is included in "Nonregulated revenues" line in our Consolidated Statements of Income (Loss).

Maryland Settlement Agreement—Customer Rate Credit
In March 2008, Constellation Energy, BGE and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

- Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC will close ongoing proceedings relating to the 1999 settlement.
- BGE provided its residential electric customers $189.1 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.
- BGE customers are relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2, scheduled to occur no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Senate Bill 1, which had been enacted in June 2006.
- BGE resumed collection of the residential return portion of the SOS administrative charge, which had been eliminated under Senate Bill 1, on June 1, 2008 and will continue collection through May 31, 2010 without having to rebate it to all residential electric customers. This will total approximately $40 million over this period. This charge will be suspended from June 1, 2010 through December 31, 2016.
- Any electric distribution base rate case filed by BGE will not result in increased distribution rates prior to October 2009, and any increase in electric distribution revenue awarded will be capped at 5% with certain exceptions. Any subsequent electric distribution base rate case may not be filed prior to August 1, 2010. The agreement does not govern or affect BGE's ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases or increases associated with standard offer service power supply auctions.
- Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense approximately $14 million in 2008 without impacting rates charged to customers.
- Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.
- Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

2007 Events

	Pre-Tax	After-Tax
	(In millions)	
Impairment losses and other costs	**$(20.2)**	**$(12.2)**
Workforce reduction costs	**(2.3)**	**(1.4)**
Gain on sales of equity of CEP	**63.3**	**39.2**
Loss from discontinued operations		
High Desert	**(2.4)**	**(0.3)**
Puna	**—**	**(0.6)**
Total loss from discontinued operations	**(2.4)**	**(0.9)**
Total other items	**$ 38.4**	**$ 24.7**

Impairment Losses and Other Costs
In connection with the termination of the merger agreement with FPL Group, Inc. (FPL Group) in October 2006, we acquired certain rights relating to a wind development project in Western Maryland. In the second quarter of 2007, we elected not to make the additional investment that was required at that time to retain our rights in the project; therefore, we recorded a charge of $20.2 million pre-tax to write-off our investment in these development rights.

Workforce Reduction Costs
In June 2007, we approved a restructuring of the workforce at the Nine Mile Point nuclear facility related to the elimination of 23 positions. We recognized costs of $2.3 million pre-tax related to recording a liability for severance and other benefits under our existing benefit programs. We completed this workforce reduction in 2008.

Gain on Sales of Equity of CEP
In November 2006, CEP, a limited liability company formed by Constellation Energy completed an initial public offering of 5.2 million common units at $21 per unit. In April 2007, CEP acquired 100% ownership of certain coalbed methane properties located in the Cherokee Basin in Kansas and Oklahoma. This

acquisition was funded through CEP's sale of equity in which we did not participate.

As a result of the April 2007 equity issuance by CEP, our ownership percentage in CEP fell below 50 percent. Therefore, during the second quarter of 2007, we deconsolidated CEP and began accounting for our investment using the equity method. We discuss the equity method of accounting in more detail in *Note 1*.

In July and September 2007, CEP issued additional equity. In connection with our equity ownership in CEP, we recognize gains on CEP's equity issuances in the period that the equity is sold as common units or when converted to common units. The details of the 2007 CEP equity issuances, as well as the gains recognized by us, are summarized below:

	Units Issued	Price/ Unit	Proceeds to CEP	Pre-tax gain
	(In millions, except price/unit)			
April 2007 Sale				
Common units	2.2	$26.12	$ 58	$12.5
Class E units	0.1	25.84	2	0.4
July 2007 Sale				
Common units	2.7	35.25	94	20.0
Class F units	2.6	35.25	92	11.2
September 2007 Sale				
Common units	2.5	42.50	105	19.2

Discontinued operations

In the fourth quarter of 2006, we completed the sale of six natural gas-fired plants, including the High Desert facility, which was classified as discontinued operations. We recognized an after-tax loss of $0.3 million as a component of "Income (loss) from discontinued operations" for 2007 due to post-closing working capital and income tax adjustments. In addition, during 2007, we recognized an after-tax loss of $0.6 million relating to income tax adjustments arising from the June 2004 sale of a geothermal generating facility in Hawaii that was also previously classified as discontinued operations.

3 Information by Operating Segment

Our reportable operating segments are—Merchant Energy, Regulated Electric, and Regulated Gas:

- At December 31, 2009, our merchant energy business is nonregulated and includes:
  - fossil and renewable generating facilities, interests in nuclear and hydroelectric generating facilities, qualifying facilities, and power projects in the United States,
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - gas retail energy products and services to commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),
  - upstream (exploration and production) natural gas operations, and
  - generation operations and maintenance.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Central Maryland.

Our remaining nonregulated businesses:

- design, construct, and operate renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America,
- provide energy performance contracting and energy efficiency engineering services,
- provide home improvements, service electric and gas appliances, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas marketing to residential customers in Central Maryland, and
- develop and deploy new nuclear plants in North America.

Prior to June 30, 2009, our merchant energy business segment included additional activities that have been divested as part of our strategy to improve our liquidity and reduce our business risk. The divested activities include:

- our international commodities operation, which was divested in March 2009,
- our gas trading operation, which was divested on April 1, 2009,
- our ownership of a uranium market participant, which was divested on June 30, 2009, and
- our investment in a shipping joint venture, which was divested in the third quarter of 2009.

On November 6, 2009, we sold a 49.99% membership interest in CENG. As a result, we deconsolidated CENG and removed all of the assets and liabilities from this business from our merchant energy segment. We now account for our retained investment as an equity method investment. We discuss this transaction in more detail in *Note 2*.

As a result of the successful execution of these initiatives, as well as our other initiatives that we have undertaken to reduce risk in our merchant energy business, we have reduced our exposure to activities that require contingent capital support and improved our liquidity. In turn, the results for our merchant energy business segment will be materially different from prior periods.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technologies and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the following table.

	Reportable Segments			Holding Company and Other Nonregulated Businesses	Eliminations	Consolidated
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business			
				(In millions)		
2009						
Unaffiliated revenues	**$11,769.8**	**$2,820.7**	**$ 753.8**	**$ 254.5**	**$ —**	**$15,598.8**
Intersegment revenues	**663.7**	**—**	**4.5**	**0.1**	**(668.3)**	**—**
Total revenues	**12,433.5**	**2,820.7**	**758.3**	**254.6**	**(668.3)**	**15,598.8**
Depreciation, depletion, and amortization	**250.2**	**218.1**	**44.0**	**76.8**	**—**	**589.1**
Fixed charges	**207.5**	**113.3**	**26.0**	**0.5**	**2.8**	**350.1**
Income tax expense (benefit)	**2,938.2**	**50.9**	**17.1**	**(19.4)**	**—**	**2,986.8**
Net income (loss) (1)	**4,435.0**	**79.1**	**25.5**	**(36.2)**	**—**	**4,503.4**
Net income (loss) attributable to common stock	**4,381.0**	**68.9**	**22.5**	**(29.0)**	**—**	**4,443.4**
Segment assets	**13,535.6**	**4,994.5**	**1,413.4**	**4,781.7**	**(1,180.8)**	**23,544.4**
Capital expenditures	**1,119.0**	**373.0**	**66.0**	**37.0**	**—**	**1,595.0**
2008						
Unaffiliated revenues	$ 15,798.6	$ 2,679.5	$ 1,004.7	$ 259.1	$ —	$ 19,741.9
Intersegment revenues	891.9	0.2	19.3	0.2	(911.6)	—
Total revenues	16,690.5	2,679.7	1,024.0	259.3	(911.6)	19,741.9
Depreciation, depletion, and amortization	287.1	184.2	43.7	68.2	—	583.2
Fixed charges	191.4	113.5	26.3	1.7	16.2	349.1
Income tax (benefit) expense	(99.5)	(4.9)	25.5	0.6	—	(78.3)
Net (loss) income (2)	(1,374.6)	11.1	40.4	4.7	—	(1,318.4)
Net (loss) income attributable to common stock	(1,357.4)	1.1	37.2	4.7	—	(1,314.4)
Segment assets (3)	13,857.9	4,620.3	1,392.4	3,508.5	(1,095.0)	22,284.1
Capital expenditures	1,675.0	388.0	74.0	86.0	—	2,223.0
2007						
Unaffiliated revenues	$ 17,537.0	$ 2,455.6	$ 943.0	$ 249.5	$ —	$ 21,185.1
Intersegment revenues	1,199.4	0.1	19.8	0.3	(1,219.6)	—
Total revenues	18,736.4	2,455.7	962.8	249.8	(1,219.6)	21,185.1
Depreciation, depletion, and amortization	269.9	187.4	46.8	53.7	—	557.8
Fixed charges	86.9	97.6	27.7	8.6	71.6	292.4
Income tax expense	332.7	64.6	22.8	8.2	—	428.3
Income from discontinued operations	(0.9)	—	—	—	—	(0.9)
Net income (4)	677.0	107.9	32.0	16.6	—	833.5
Net income attributable to common stock	678.3	97.9	28.8	16.5	—	821.5
Segment assets	15,947.7	4,378.4	1,293.6	458.6	(336.0)	21,742.3
Capital expenditures	1,178.0	340.0	62.0	85.0	—	1,665.0

(1) Our merchant energy business recognized the following after-tax items: gain on sale of a 49.99% membership interest in CENG to EDF of $4,456.1 million, amortization of basis difference in investment in CENG of ($17.8) million, loss on the early extinguishment of zero coupon senior notes of $10.0 million, impairment losses and other costs of $84.7 million, workforce reduction costs of $9.3 million, merger termination and strategic alternatives costs of $13.8 million, losses on divestitures, which include losses on the sales of the international commodities and gas trading operations, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, earnings that are no longer part of our core business, of $371.9 million, and impairment charges of our nuclear decommissioning trust assets through November 6, 2009 of $46.8 million. Our regulated electric and gas businesses recognized after-tax charges of $56.7 million and $10.4 million, respectively, for the accrual of a residential customer credit. Our holding company and other nonregulated businesses recognized after-tax charges of $11.5 million for impairment losses and other costs and $2.9 million for losses on divestitures. We discuss these items in more detail in Note 2.

(2) Our merchant energy business recognized the following after-tax charges: impairment losses and other costs of $470.7 million, workforce reduction costs of $9.3 million, merger termination and strategic alternatives costs of $1,204.4 million, net emission allowance write-down of $28.7 million, a net gain on the sale of upstream gas properties of $16.0 million, a gain on sale of a dry bulk vessel of $18.9 million, and an impairment charge of our nuclear decommissioning trust assets of $82.0 million. Our regulated electric business recognized after-tax charges related to workforce reduction costs of $2.8 million and the Maryland settlement credit of $110.5 million. Our regulated gas business recognized an after-tax charge related to workforce reduction costs of $1.0 million. Our holding company and other nonregulated business recognized an after-tax charge related to workforce reduction costs of $0.3 million. We discuss these items in more detail in Note 2.

(3) At December 31, 2008, Holding Company and Other Nonregulated segment assets include approximately $1.6 billion of intercompany receivables from the merchant energy business, primarily relating to the allocation of merger termination costs of approximately $1.2 billion to these businesses, and $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF. These funds are held at the holding company and are restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.

(4) Our merchant energy business recognized an after-tax loss of $12.2 million related to a cancelled wind development project, an after-tax gain of $39.2 million on sales of CEP equity, and an after-tax charge of $1.4 million for workforce reduction costs as described in more detail in Note 2.

4 Investments

Investments in Joint Ventures, Qualifying Facilities and Power Projects, and CEP

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP consist of the following:

At December 31,	**2009**	2008
	(In millions)	
Joint Ventures:		
CENG	**$5,222.9**	$ —
UNE	**122.0**	51.0
Shipping JV	**—**	59.9
Qualifying facilities and domestic power projects:		
Coal	**119.7**	119.5
Hydroelectric	**55.2**	55.6
Geothermal	**40.0**	37.0
Biomass	**56.2**	58.2
Fuel Processing	**24.3**	15.0
Solar	**6.9**	6.9
CEP	**—**	17.7
Other	**—**	0.2
Total	**$5,647.2**	$421.0

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP were accounted for under the following methods:

At December 31,	**2009**	2008
	(In millions)	
Equity method	**$5,640.3**	$414.1
Cost method	**6.9**	6.9
Total	**$5,647.2**	$421.0

We are actively involved in our nuclear joint ventures, qualifying facilities and power projects. Our percentage voting interests in these investments accounted for under the equity method range from 20% to 50.01%. Equity in earnings of these investments is as follows:

Year ended December 31,	**2009**	2008	2007
		(In millions)	
CENG	**$ 33.9**	$ —	$ —
Amortization of basis difference in CENG (see *Note 2* for more detail)	**(29.6)**	—	—
Total equity investment earnings— CENG	**4.3**	—	—
UNE	**(24.7)**	(5.9)	1.9
Shipping JV	**(1.8)**	37.4	(0.6)
CEP	**(4.6)**	7.7	6.1
Qualifying facilities and domestic power projects	**20.7**	37.2	0.7
Total equity investment earnings	**$ (6.1)**	$76.4	$ 8.1

We describe each of these investments below.

Joint Ventures

CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG, our nuclear generation and operation business, to EDF. As a result of this transaction, we deconsolidated CENG and began to record our 50.01% investment in CENG under the equity method of accounting. Because the transaction occurred on November 6, 2009, we recorded $4.3 million of equity investment earnings in CENG, which represents our share of earnings from CENG from November 6, 2009 through December 31, 2009, net of the amortization of the basis difference in CENG. The basis difference is the difference between the fair value of our investment in CENG at closing and our share of the underlying equity in CENG, because the underlying assets and liabilities of CENG were retained at their carrying value. See *Note 2* for a more detailed discussion.

Summarized balance sheet information for CENG is as follows:

At December 31, 2009	
	(In millions)
Current assets	$ 513.0
Noncurrent assets	4,404.2
Current liabilities	556.9
Noncurrent liabilities	1,716.1

Summarized income statement information for CENG is as follows:

For the period from November 6, 2009 through December 31, 2009	
	(In millions)
Revenues	$217.6
Fuel and purchased energy expenses	29.8
Income from operations	64.6
Net income	68.5

In future periods, we may be eligible for distributions from CENG in excess of our 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. We would record these distributions, if realized, in earnings in the period received.

UNE
In August 2007, we formed a joint venture, UNE with EDF. We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. The agreement with EDF includes a phased-in investment of $625 million by EDF in UNE. We and EDF have contributed assets to UNE with the following carrying values:

	Investment by	
Year ended December 31,	Constellation Energy	EDF
	(In millions)	
2009 (1)	**$91.6**	$ 91.6
2008	**1.7**	175.0
2007	**48.7**	350.0

(1) Amounts contributed to fund UNE's capital requirements. EDF's contribution does not count toward its $625 million obligation.

EDF will contribute up to an additional $100 million to UNE, for a total of $625 million, upon reaching additional licensing milestones.

As of December 31, 2009, UNE's capitalized construction work in progress was approximately $510 million. Such amounts are being capitalized based on UNE's assessment that construction of new nuclear projects is probable. Should that expectation change, previously capitalized costs would be written-off by UNE and we would be required to recognize our proportionate share of such charges. In the event that our portion of any losses incurred by UNE exceed our investment, we will continue to record those losses in earnings unless it is determined that UNE will cease operations and subsequently be dissolved.

We also believe that UNE's construction of new nuclear projects is probable. Should that assessment change, we would be required to evaluate our investment in UNE for potential impairment.

Shipping JV
In December 2006, we formed a shipping joint venture in which our merchant energy business had a 50% ownership interest. We sold our interest in this joint venture during 2009 for negligible proceeds.

Qualifying Facilities and Power Projects
Our merchant energy business holds up to a 50% voting interest in 18 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 18 projects, 16 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policies Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

CEP
In November 2006, CEP, a limited liability company formed by our merchant energy business, completed an initial public offering. As of December 31, 2006, we owned approximately 54% of CEP and consolidated CEP. During the second quarter of 2007, CEP issued additional equity to the public and our ownership percentage fell below 50%. Therefore, we deconsolidated CEP and began accounting for our investment using the equity method. As of December 31, 2009, we hold a 28.5% voting interest in CEP.

Investments Classified as Available-for-Sale
We classify the following investments as available-for-sale:
- nuclear decommissioning trust funds (through November 6, 2009), and
- trust assets securing certain executive benefits.

This means we do not expect to hold these investments to maturity, and we do not consider them trading securities. We record these investments at fair value on our Consolidated Balance Sheets.

We show the fair values, gross unrealized gains and losses, and adjusted cost basis for all of our available-for-sale securities in the following tables. We use specific identification to determine cost in computing realized gains and losses.

At December 31, 2009	Adjusted Cost	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Money market funds	**$ 0.1**	**$ —**	**$—**	**$ 0.1**
Mutual funds	**16.1**	**2.8**	**—**	**18.9**
Totals	**$16.2**	**$2.8**	**$—**	**$19.0**

At December 31, 2008	Adjusted Cost	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Money market funds	$ 17.6	$ —	$ —	$ 17.6
Marketable equity securities	700.9	41.5	(2.1)	740.3
Corporate debt and U.S Treasuries	224.8	6.8	—	231.6
State municipal bonds	46.2	1.3	—	47.5
Totals	$989.5	$49.6	$(2.1)	$1,037.0

On November 6, 2009, we removed the nuclear decommissioning trust fund assets from our Consolidated Balance Sheets as part of the deconsolidation of CENG described in *Note 2*. Prior to November 6, 2009, the investments in our nuclear decommissioning trust funds were managed by third parties who have independent discretion over the purchases and sales of securities. We recognized impairments for any of these investments for which the fair value declines below our book value. We recognized $62.6 million and $165.0 million in pre-tax impairment losses on our nuclear decommissioning trust investments during 2009 and 2008, respectively. There were immaterial impairments in 2007. These impairments are included as part of gross realized losses in the following table.

Gross and net realized gains and losses on available-for-sale securities were as follows:

Year ended December 31,	**2009**	2008	2007
		(In millions)	
Gross realized gains	**$ 29.8**	$ 49.6	$ 33.5
Gross realized losses	**(86.9)**	(210.4)	(30.9)
Net realized (losses) gains	**$(57.1)**	$(160.8)	$ 2.6

Investments in Variable Interest Entities

As of December 31, 2009, we consolidated three variable interest entities (VIE) in which we were the primary beneficiary, and we had significant interests in six VIEs for which we did not have controlling financial interests and, accordingly, were not the primary beneficiary. See *Note 1* for estimated impacts of new accounting requirements for VIEs in 2010.

Consolidated Variable Interest Entities

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy-remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1.

BGE determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE, and we, consolidated BondCo.

The BondCo assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2009, 2008, and 2007, BGE remitted $85.8 million, $87.2 million, and $38.4 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2009. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

During the second quarter of 2009, our retail gas customer supply operation formed two new entities and combined them with our existing retail gas customer supply operation into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While we own 100% of these entities, we determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support we provide in the form of a letter of credit and a parental guarantee. We are the primary beneficiary of the retail gas entity group; accordingly, we consolidate the retail gas entity group as a VIE, including the existing retail gas customer supply operation, which we formerly consolidated as a voting interest entity.

The gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to us,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- We provided a $100 million parental guarantee and a $65 million letter of credit to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee and the letter of credit, we do not have any contractual or other obligations to provide additional financial support to the retail gas entity group. The retail gas entity group creditors do not have any recourse to our general credit. Finally, we did not provide any financial support to the retail gas entity group during 2009, other than the equity contributions, parental guarantee and the letter of credit.

We also consolidate a retail power supply VIE for which we became the primary beneficiary in 2008 as a result of a modification to its contractual arrangements that changed the allocation of the economic risks and rewards of the VIE among the variable interest holders. The consolidation of this VIE did not have a material impact on our financial results or financial condition.

The carrying amounts and classification of the above consolidated VIEs' assets and liabilities included in our consolidated financial statements at December 31, 2009 are as follows:

	(In millions)
Current assets	$608.9
Noncurrent assets	67.7
Total Assets	$676.6
Current liabilities	$509.9
Noncurrent liabilities	420.3
Total Liabilities	$930.2

All of the assets in the table above are restricted for settlement of the VIE obligations and all of the liabilities in the preceding table can only be settled using VIE resources.

During 2010, as part of the 2009 order from the Maryland PSC approving our transaction with EDF, we created RF HoldCo, a bankruptcy-remote special purpose subsidiary to hold all of the common equity interests in BGE. This subsidiary is not a VIE. However, due to our ownership structure, we will consolidate this subsidiary as a voting interest entity.

BGE and RF HoldCo are separate legal entities and are not liable for the debts of Constellation Energy. Accordingly, creditors of Constellation Energy may not satisfy their debts from the assets of BGE and RF HoldCo except as required by applicable law or regulation. Similarly, Constellation Energy is not liable for the debts of BGE or RF HoldCo. Accordingly, creditors of BGE and RF HoldCo may not satisfy their debts from the assets of Constellation Energy except as required by applicable law or regulation.

Unconsolidated Variable Interest Entities

As of December 31, 2009, we had significant interests in six VIEs for which we were not the primary beneficiary. We have not provided any material financial or other support to these entities during 2009.

The nature of these entities and our involvement with them are described in the following table:

VIE Category	Nature of Entity Financing	Nature of Constellation Energy Involvement	Obligations or Requirement to Provide Financial Support	Date of Involvement
Power contract monetization entities (2 entities)	Combination of debt and equity financing	Power sale agreements, loans, and guarantees	$34.7 million in letters of credit	March 2005
Power projects and fuel supply entities (4 entities)	Combination of debt and equity financing	Equity investments and guarantees	$2.0 million debt guarantee and working capital funding	Prior to 2003

For purposes of aggregating the various VIEs for disclosure, we evaluated the risk and reward characteristics for, and the significance of, each VIE. We discuss in greater detail the nature of our involvement with the power contract monetization VIEs in the *Power Contract Monetization VIEs* section below.

The following is summary information available as of December 31, 2009 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
	(In millions)		
Total assets	$568.3	$338.6	$906.9
Total liabilities	460.4	77.9	538.3
Our ownership interest	—	62.6	62.6
Other ownership interests	107.9	198.1	306.0
Our maximum exposure to loss	34.7	64.6	99.3
Carrying amount and location of variable interest on balance sheet:			
—Other investments	—	62.6	62.6

Our maximum exposure to loss is the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2009 consists of the following:

- outstanding receivables, loans, and letters of credit totaling $34.7 million,
- the carrying amount of our investment totaling $62.6 million, and
- debt and payment guarantees totaling $2.0 million.

We assess the risk of a loss equal to our maximum exposure to be remote and, accordingly have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of our variable interests in these variable interest entities.

Power Contract Monetization VIEs

In March 2005, our merchant energy business closed a transaction in which we assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, we sell power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013. In connection with this transaction, a third party acquired the equity of the VIEs and we loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to us in lieu of repaying the loan. In this event, we would have the right to seek recovery of our losses from the electric distribution utility.

5 Intangible Assets

Goodwill

Goodwill is the excess of the cost of an acquisition over the fair value of the net assets acquired. As of December 31, 2009, our goodwill balance was primarily related to our other nonregulated businesses. Prior to September 30, 2008, our goodwill balance was primarily related to our merchant energy business acquisitions. Goodwill is not amortized; rather, it is evaluated for impairment at least annually. We evaluated our goodwill in 2008 and recorded a $266.5 million impairment charge in 2008, which related solely to our merchant energy segment. We discuss this impairment charge in more detail in *Note 2.*

The changes in the gross amount of goodwill and the accumulated impairment losses for the years ended December 31, 2009 and 2008 are as follows:

At December 31,	**2009**	2008
	(In millions)	
Balance as of January 1,:		
Gross goodwill	**$ 271.1**	$ 261.3
Accumulated impairment losses	**(266.5)**	—
Net goodwill	**4.6**	261.3
Goodwill acquired	**18.6**	9.8
Impairment losses	**—**	(266.5)
Other purchase price adjustments	**2.3**	—
Balance as of December 31,		
Gross goodwill	**292.0**	271.1
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**$ 25.5**	$ 4.6

For tax purposes, $18.6 million of our goodwill balance at December 31, 2009 is deductible.

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	**2009**			2008		
	Gross Carrying Amount	**Accumul-ated Amortiz-ation**	**Net Asset**	Gross Carrying Amount	Accumul-ated Amortiz-ation	Net Asset
			(In millions)			
Software	**$580.5**	**$(347.3)**	**$233.2**	$554.9	$(291.5)	$263.4
Permits and licenses	**2.2**	**(0.8)**	**1.4**	64.9	(10.0)	54.9
Operating manuals and procedures	**—**	**—**	**—**	38.6	(8.6)	30.0
Other	**29.0**	**(13.9)**	**15.1**	43.9	(22.6)	21.3
Total	**$611.7**	**$(362.0)**	**$249.7**	$702.3	$(332.7)	$369.6

BGE had intangible assets with a gross carrying amount of $242.5 million and accumulated amortization of $148.8 million at December 31, 2009 and $217.0 million and accumulated amortization of $131.4 million at December 31, 2008 that are included in the table above. Substantially all of BGE's intangible assets relate to software.

We recognized amortization expense related to our intangible assets as follows:

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Nonregulated businesses	**$74.2**	$66.8	$51.9
BGE	**23.6**	20.1	20.2
Total Constellation Energy	**$97.8**	$86.9	$72.1

The following is our, and BGE's, estimated amortization expense related to our intangible assets for 2010 through 2014 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2009:

Year Ended December 31,	2010	2011	2012	2013	2014
			(In millions)		
Estimated amortization expense— Nonregulated businesses	$56.7	$45.1	$25.7	$ 9.9	$ 4.4
Estimated amortization expense—BGE	24.6	21.9	15.3	11.6	7.4
Total estimated amortization expense— Constellation Energy	$81.3	$67.0	$41.0	$21.5	$11.8

Unamortized Energy Contracts

As discussed in *Note 1*, unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as normal purchases and normal sales, which we previously recorded as derivative assets and liabilities. Unamortized energy contract assets also include the power purchase agreement entered into with CENG with a fair value of approximately $0.8 billion. See *Note 16* for more details on this power purchase agreement.

We present separately in our Consolidated Balance Sheets the net unamortized energy contract assets and liabilities for these contracts. The table below presents the gross and net carrying amount and accumulated amortization of the net liability that we have recorded in our Consolidated Balance Sheets:

At December 31	**2009**			2008		
	Carrying Amount	**Accumul-ated Amortiz-ation**	**Net Liability**	Carrying Amount	Accumul-ated Amortiz-ation	Net Liability
			(In millions)			
Unamortized energy contracts, net	**$(1,587.1)**	**$1,584.5**	**$ (2.6)**	$(2,332.3)	$1,286.8	$(1,045.5)

We recognized amortization expense of $353.1 million, $390.4 million, and $423.7 million related to these energy contract assets for the years ended December 31, 2009, 2008, and 2007 for our nonregulated businesses.

The table below presents the estimated amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	2010	2011	2012	2013	2014
			(In millions)		
Estimated amortization	$45.6	$295.1	$(89.8)	$(92.3)	$(72.1)

6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain regulated expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (Loss) (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,	**2009**	2008
	(In millions)	
Deferred fuel costs		
Rate stabilization deferral	**$ 477.5**	$ 536.3
Other	**14.3**	24.4
Electric generation-related regulatory asset	**102.5**	118.0
Net cost of removal	**(210.1)**	(198.0)
Income taxes recoverable through future rates (net)	**67.6**	63.2
Deferred smart energy savers program costs	**22.1**	15.6
Deferred postretirement and postemployment benefit costs	**9.6**	12.9
Deferred environmental costs	**6.5**	7.7
Workforce reduction costs	**1.5**	—
Other (net)	**(4.6)**	(5.7)
Total regulatory assets (net)	**486.9**	574.4
Less: Current portion of regulatory assets (net)	**72.5**	79.7
Long-term portion of regulatory assets (net)	**$ 414.4**	$ 494.7

Deferred Fuel Costs

Rate Stabilization Deferral

In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006 to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the Maryland PSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306.4 million of electricity purchased for resale expenses and certain applicable carrying charges as a regulatory asset related to the rate stabilization plans. During 2009 and 2008, BGE recovered $51.4 million and $57.1 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. Customers who participated in the deferral from June 1, 2007 to December 31, 2007 are repaying the deferred charges without interest over a 21-month period which began in April 2008 and ended in December 2009.

Other

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of purchased energy and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from our customers.

We exclude deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our fuel rates.

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities. BGE established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $62.8 million as of December 31, 2009 and $72.4 million as of December 31, 2008. We will continue to amortize this amount through 2017.

Net Cost of Removal

As discussed in *Note 1*, we use the group depreciation method for the regulated business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America and has been widely used in the energy, transportation, and telecommunication industries.

Historically, under the group depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, the recognition of expected net future costs of removal is shown as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the group depreciation method, including cost of removal, under regulatory accounting. For ratemaking purposes, net cost of removal is a component of depreciation expense and the related accumulated depreciation balance is included as a net reduction to BGE's rate base investment. For financial reporting purposes, BGE continues to accrue for the future cost of removal for its regulated gas and electric assets by increasing a regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Smart Energy Savers Program Costs

Deferred Smart Energy Savers Program costs are the costs incurred to implement demand response, conservation, and advanced metering programs. These programs are designed to help BGE manage peak demand, improve system reliability, reduce customer consumption, and improve service to customers by giving customers greater control over their energy use. Actual costs incurred in the demand response program, which began in January 2008, are being amortized over a 5-year period from the date incurred pursuant to an order by the Maryland PSC. Actual costs incurred in the conservation program, which began in February 2009, are being amortized as incurred pursuant to an order by the Maryland PSC.

Deferred Postretirement and Postemployment Benefit Costs

We record a regulatory asset for the deferred postretirement and postemployment benefit costs in excess of the costs we included in the rates we charged our customers through 1997. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We amortized $21.6 million of these costs (the amount we had incurred through October 1995) and are amortizing $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders. We applied for and received rate relief for an additional $5.4 million of clean-up costs incurred during the period from July 2000 through November 2005. These costs are being amortized over a 10-year period that began in January 2006.

Workforce Reduction Costs

The portion of the costs associated with our 2008 workforce reduction program that relate to BGE's gas business were deferred in 2009 as a regulatory asset in accordance with the Maryland PSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009.

Other (Net)

Other regulatory assets are comprised of a variety of current assets and liabilities that do not earn a regulatory rate of return due to their short-term nature.

7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point, owned by CENG, offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. In connection with the deconsolidation of CENG as a result of the investment in CENG by EDF on November 6, 2009, the Nine Mile Point plan is no longer included in our consolidated results. In addition, benefit plan assets and obligations relating to CENG employees that previously participated in our plans were transferred into new CENG plans that are no longer included in our consolidated results. Therefore, the tables below include the benefits for the CENG plans, including Nine Mile Point, only through November 6, 2009.

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans. The following table summarizes our defined benefit liabilities and their classification in our Consolidated Balance Sheets:

At December 31,	**2009**	2008
	(In millions)	
Pension benefits	**$411.7**	$ 936.7
Postretirement benefits	**322.3**	415.4
Postemployment benefits	**50.6**	59.9
Total defined benefit obligations	**784.6**	1,412.0
Less: Amount recorded in other current liabilities	**40.7**	57.7
Total noncurrent defined benefit obligations	**$743.9**	$1,354.3

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include basic qualified plans that most employees participate in and several non-qualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the qualified plans by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2009 and 2008 were mostly marketable equity and fixed income securities.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels or final base pay. We do not fund these plans. For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective in 2002, we amended our postretirement medical plans for all subsidiaries other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries concluded that prescription drug benefits available under our postretirement medical plan are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. This subsidy reduced our 2009 Accumulated Postretirement Benefit Obligation by $28.4 million and our 2009 postretirement medical payments by $2.8 million.

Liability Adjustments

At December 31, 2009 and 2008, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans		Non-Qualified	
At December 31, 2009	Nine Mile	Other	Plans	Total
		(In millions)		
Accumulated benefit obligation	**$—**	**$1,277.5**	**$84.1**	**$1,361.6**
Fair value of assets	**—**	**1,058.1**	**—**	**1,058.1**
Unfunded obligation	**$—**	**$ 219.4**	**$84.1**	**$ 303.5**

	Qualified Plans		Non-Qualified	
At December 31, 2008	Nine Mile	Other	Plans	Total
		(In millions)		
Accumulated benefit obligation	$123.7	$1,417.3	$99.8	$1,640.8
Fair value of assets	63.3	804.3	—	867.6
Unfunded obligation	$ 60.4	$ 613.0	$99.8	$ 773.2

We are required to reflect the funded status of our pension plans in terms of the projected benefit obligation, which is higher than the accumulated benefit obligation because it includes the impact of expected future compensation increases on the pension obligation. We reflect the funded status of our postretirement benefits in terms of the accumulated postretirement benefit obligation.

The following table summarizes the impacts of funded status adjustments recorded during 2009 and 2008:

	Pension Liability	Postretirement Benefit Liability	Accumulated Other Comprehensive Income (Loss) Pre-tax	After-tax
	(In millions)			
December 31, 2009	**$ (49.3)**	**$ 1.0**	**$ 48.3**	**$ 25.4**
November 6, 2009 (1)	$ (211.7)	$ (20.9)	$ 232.6	$ 138.0
December 31, 2008	$ 590.7	$ (9.5)	$ (581.2)	$ (347.1)

(1) We performed a remeasurement of our pension and postretirement obligations at November 6, 2009 in connection with the separation of a portion of those plans upon the deconsolidation of CENG.

Obligations and Assets

As a result of workforce reduction initiatives, pension and postretirement special termination benefits were recorded in 2009, 2008 and 2007. We discuss the workforce reduction initiatives further in *Note 2.*

We show the change in the benefit obligations and plan assets of the pension and postretirement benefit plans in the following tables. Postretirement benefit plan amounts are presented net of expected reimbursements under Medicare Part D.

	Pension Benefits		Postretirement Benefits	
	2009	2008	**2009**	2008
	(In millions)			
Change in benefit obligation (1)				
Benefit obligation at January 1	**$1,804.3**	$1,644.2	**$415.4**	$421.5
Service cost	**50.8**	55.4	**6.3**	6.1
Interest cost	**101.1**	100.2	**22.6**	24.0
Plan amendments	**2.4**	12.1	**—**	—
Plan participants' contributions	**—**	—	**10.2**	10.8
Actuarial loss (gain)	**55.8**	102.4	**1.0**	(9.5)
Separation of CENG Plan	**(410.5)**	—	**(98.6)**	—
Settlements	**(19.0)**	—	**—**	—
Special termination benefits	**0.1**	2.2	**—**	0.8
Benefits paid (2)(3)	**(115.2)**	(112.2)	**(34.6)**	(38.3)
Benefit obligation at December 31	**$1,469.8**	$1,804.3	**$322.3**	$415.4

(1) Amounts reflect projected benefit obligation for pension benefits and accumulated postretirement benefit obligation for postretirement benefits.
(2) Pension benefits paid include annuity payments and lump-sum distributions.
(3) Postretirement benefits paid are net of Medicare Part D reimbursements.

	Pension Benefits		Postretirement Benefits	
	2009	2008	**2009**	2008
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$ 867.6**	$1,258.5	**$ —**	$ —
Actual return on plan assets	**217.6**	(364.9)	**—**	—
Employer contribution (1)	**341.5**	86.2	**24.4**	27.5
Plan participants' contributions	**—**	—	**10.2**	10.8
Separation of CENG Plan	**(234.4)**	—	**—**	—
Settlements	**(19.0)**	—	**—**	—
Benefits paid (2)(3)	**(115.2)**	(112.2)	**(34.6)**	(38.3)
Fair value of plan assets at December 31	**$1,058.1**	$ 867.6	**$ —**	$ —

(1) Includes benefit payments for unfunded plans.
(2) Pension benefits paid include annuity payments and lump-sum distributions.
(3) Postretirement benefits paid are net of Medicare Part D reimbursements.

Net Periodic Benefit Cost and Amounts Recognized in Other Comprehensive Income

We show the components of net periodic pension benefit cost in the following table:

Year Ended December 31,	**2009**	2008	2007
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	**$ 50.8**	$ 55.4	$ 49.4
Interest cost	**101.1**	100.2	94.7
Expected return on plan assets	**(118.9)**	(111.3)	(102.6)
Amortization of unrecognized prior service cost	**10.9**	10.9	5.2
Recognized net actuarial loss	**38.3**	24.7	32.7
Amount capitalized as construction cost	**(10.2)**	(10.2)	(11.7)
Net periodic pension benefit cost (1)	**$ 72.0**	$ 69.7	$ 67.7

(1) Net periodic pension benefit cost excludes settlement charge of $9.0 million and termination benefits of $0.1 million in 2009, termination benefits of $2.2 million in 2008, and termination benefits of $1.2 million in 2007. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $27.9 million in 2009, $25.5 million in 2008, and $32.1 million in 2007. The vast majority of our retirees are BGE employees.

We show the components of net periodic postretirement benefit cost in the following table:

Year Ended December 31,	**2009**	2008	2007
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	**$ 6.3**	$ 6.1	$ 6.5
Interest cost	**22.6**	24.0	24.4
Amortization of transition obligation	**2.1**	2.1	2.1
Recognized net actuarial loss	**2.2**	2.0	4.1
Amortization of unrecognized prior service cost	**(3.4)**	(3.5)	(3.5)
Amount capitalized as construction cost	**(6.3)**	(7.6)	(7.7)
Net periodic postretirement benefit cost (1)	**$23.5**	$23.1	$25.9

(1) *Net periodic postretirement benefit cost excludes termination benefits of $0.8 million in 2008 and $0.3 million in 2007. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $18.7 million in 2009, $20.4 million in 2008, and $22.7 million in 2007.*

In determining net periodic pension benefit cost, we apply our expected return on plan assets to a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

The following is a summary of amounts we have recorded in "Accumulated other comprehensive income" and of expected amortization of those amounts over the next twelve months:

	Pension Benefits		Postretirement Benefits		Expected Amortiz-ation Next 12 Months
	2009	2008	**2009**	2008	
	(In millions)				
Unrecognized actuarial loss	**$702.2**	$ 999.8	**$ 51.5**	$ 78.7	$36.3
Unrecognized prior service cost	**9.9**	22.5	**(13.9)**	(22.6)	1.3
Unrecognized transition obligation	**—**	—	**6.2**	8.5	2.1
Total	**$712.1**	$1,022.3	**$ 43.8**	$ 64.6	$39.7

Expected Cash Benefit Payments

The pension and postretirement benefits we expect to pay in each of the next five calendar years and in the aggregate for the subsequent five years are shown in the following table. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2009, but include benefits attributable to estimated future employee service.

		Postretirement Benefits		
	Pension Benefits	Before Medicare Part D	Subsidy	After Medicare Part D
	(In millions)			
2010	$102.7	$ 26.8	$ 2.2	$ 24.6
2011	94.3	27.1	2.2	24.9
2012	101.3	27.2	2.3	24.9
2013	107.0	27.5	2.4	25.1
2014	111.4	27.8	2.4	25.4
2015-2019	655.5	139.5	11.7	127.8

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations and periodic cost.

	Pension Benefits		Postretirement Benefits		Assumption Impacts Calculation of
	2009	2008	**2009**	2008	
Discount rate	**6.00%**	6.00%	**6.00%**	6.00%	Benefit Obligation and Periodic Cost
Expected return on plan assets	**8.50**	8.75	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

Our discount rate is based on a bond portfolio analysis of high quality corporate bonds whose maturities match our expected benefit payments. Our 8.50% overall expected long-term rate of return on plan assets reflected our long-term investment strategy in terms of asset mix targets and expected returns for each asset class.

We determine expected return on plan assets by applying expected future asset returns provided by external sources by asset class to our targeted long-term asset allocations. We then review actual historical plan asset returns for comparability and supplement this approach with peer group surveys when available.

Annual health care inflation rate assumptions also impact the calculation of our postretirement benefit obligation and periodic cost. We assumed the following health care inflation rates to produce average claims by year as shown below:

At December 31,	**2009**	2008
Next year	**8.0%**	8.0%
Following year	**7.5%**	7.5%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2016**	2015

A one-percentage point increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $19.0 million as of December 31, 2009 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $1.7 million annually.

A one-percentage point decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $16.6 million as of December 31, 2009 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $1.4 million annually.

Qualified Pension Plan Assets

Investment Strategy

We invest our qualified pension plan assets using the following investment objectives:

- ensure availability of funds for payment of plan benefits as they become due,
- provide for a reasonable amount of long-term growth of capital (both principal and income) without excessive volatility,
- produce investment results that meet or exceed the assumed long-term rate of return,
- reduce funded status volatility as funded status improves, and
- improve the funded status of the plan over time.

To achieve these objectives, Constellation Energy, through a management Investment Committee (the Committee), has adopted an investment strategy that divides its pension investment program into two primary portfolios:

- return seeking assets—those assets intended to generate returns in excess of pension liability growth, and
- liability hedging assets—those assets intended to have characteristics similar to pension liabilities.

Currently, the Committee allocates a substantial portion of its plan assets to return seeking assets to help reduce existing deficits in the funded status of the plan. As the funded status of our plans improve, the Committee expects to reduce its exposure to return seeking assets and increase its liability hedging assets to reduce its total risk.

Return Seeking Assets

The purpose of return seeking assets is to provide investment returns in excess of the growth of pension liabilities. This category includes a diversified portfolio of public equities, private equity, real estate, hedge funds, high yield bonds and other instruments. These assets are likely to have lower correlations with the pension liabilities and lead to higher funded status risk over shorter periods of time.

Liability Hedging Assets

The purpose of liability hedging assets, such as bonds, is to hedge against interest rate changes. Exposure to liability hedging assets is intended to reduce the volatility of plan funded status, contributions, and pension expense.

Risk Management

The Committee manages plan asset risk using several approaches. First, the assets are invested in two diverse portfolios, each of which contains investments across a spectrum of asset classes. Second, the Committee considers the long-term investment horizon of the plan, which is greater than ten years. The long-term horizon enables the Committee to tolerate the risk of investment losses in the short-term with the expectation of higher returns in the long-term. Third, the Committee employs a thorough due diligence program prior to selecting an investment, and a rigorous ongoing monitoring program once assets are invested. The Committee evaluates risk on an ongoing basis.

Asset Allocation

Plan assets are diversified across various asset classes and securities based on the investment strategy approved by the Committee. This policy allocation is long-term oriented and consistent with the risk tolerance and funded status. The target asset allocation as well as the actual allocations for 2009 and 2008 is provided below.

	Target	Actual Allocation	
At December 31,	Allocation	**2009**	2008
Global equity securities	**48%***	**57%**	57%
Fixed income securities	**30**	**27**	26
Alternative investments	**15**	**7**	11
High yield bonds	7	**7**	6
Cash and cash equivalents	—	**2**	—
Total	**100%**	**100%**	100%

* *50% passively invested; 50% actively invested*

The target asset allocation also allows for investments in financial instruments, including asset-backed securities and collateralized mortgage obligations, which are exposed to risks such as interest rate, market and overall market volatility. These instruments are sensitive to changes in economic conditions. Such changes could materially affect the amounts reported.

The actual portfolio will be rebalanced in early 2010 to reflect the recently approved target allocation. The Committee will then rebalance our portfolio periodically when the actual allocations fall outside of the ranges prescribed in the investment policy. Further, the Committee will rebalance to de-risk the portfolio as funded status improves.

Fair Value Hierarchy

We determine the fair value of the plan assets using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. We classify assets within this fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset taken as a whole.

The following table sets forth by level, within the fair value hierarchy, the investments in the Plans' master trust at fair value as of December 31, 2009:

	Level 1	Level 2	Level 3	Total Fair Value
		(In millions)		
Global equity securities	$215.4	$383.0	$ —	$ 598.4
Fixed income securities	—	289.2	—	289.2
High yield bonds	0.6	75.6	—	76.2
Cash equivalents	—	19.9	—	19.9
Alternative investments	—	—	74.4	74.4
Total	$216.0	$767.7	$74.4	$1,058.1

The following is a description of the valuation methodologies used for assets measured at fair value:

- Global equity securities are valued at unadjusted quoted market share prices within active markets (Level 1) or based on external price/spread data of comparable securities (Level 2). Common collective trust funds within this category are valued at fair value based on the unit value of the fund which is observable on a less frequent basis (Level 2). Unit values are determined by the bank sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates.
- Fixed income, high yield bonds, and cash and cash equivalents are valued based on external price data of comparable securities (Level 2).
- Alternative investments primarily consist of hedge funds and financial limited partnerships (private equity funds). These investments do not have readily determinable fair values because they are not listed on national exchanges or over-the-counter markets. We have valued these alternative investments at their respective net asset value per share (or its equivalent such as partner's capital) which has been calculated by each partnership's general partner in a manner consistent with generally accepted accounting principles in the United States of America for investment companies. Among other requirements, the partnerships must value their underlying investments at fair value. While the net asset value per share provides a reasonable approximation of fair value, the fair values of the alternative investments are estimates and, accordingly, such estimated values may differ from the values that would have been used had a ready market for the investments existed, and the differences could be material.

The following table summarizes the changes in the fair value of the Level 3 assets for the year ended December 31, 2009:

Year ended December 31, 2009	
	(In millions)
Balance at beginning of period	$ 96.3
Actual return on plan assets:	
Assets still held at year end	(2.5)
Assets sold during the year	6.4
Purchases, sales, and settlements	(10.8)
Transfers into and out of Level 3	(15.0)
Balance at end of period	$ 74.4

Contributions and Benefit Payments

We contributed $319.4 million to our qualified pension plans in 2009, even though there was no IRS required minimum contribution in 2009. We expect to contribute $37 million to our qualified pension plans in 2010. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $10 million in pension benefits for our non-qualified pension plans and approximately $25 million for retiree health and life insurance costs net of Medicare Part D during 2010.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan, and
- income replacement payments for employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

We recognized expense associated with our other postemployment benefits of $5.3 million in 2009, $1.9 million in 2008, and $16.7 million in 2007. BGE's portion of expense associated with other postemployment benefits was $4.4 million in 2009, $2.2 million in 2008, and $10.2 million in 2007.

We assumed the discount rate for other postemployment benefits to be 4.75% in 2009 and 5.00% in 2008. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsored two defined contribution plans until November 6, 2009, when upon the close of the sale of a 49.99% interest in CENG to EDF, we deconsolidated CENG and the defined contribution plan related to Nine Mile Point was removed from our books. To all remaining eligible employees of Constellation Energy, we continue to sponsor a defined contribution savings plan. The savings plan is a qualified 401(k) plan under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions were as follows:

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Nonregulated businesses	**$14.8**	$17.6	$16.1
BGE	**5.7**	5.8	5.8
Total Constellation Energy	**$20.5**	$23.4	$21.9

8 Credit Facilities and Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates. We enter into these facilities to ensure adequate liquidity to support our operations.

Constellation Energy

Our liquidity requirements are funded with credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, which support direct cash borrowings and the issuance of commercial paper, if available. We also use our credit facilities to support the issuance of letters of credit, primarily for our merchant energy business.

Constellation Energy had bank lines of credit under committed credit facilities totaling $4.0 billion at December 31, 2009 for short-term financial needs as follows:

Type of Credit Facility	Amount (In billions)	Expiration Date	Capacity Type
Syndicated Revolver (1)	$2.32	July 2012	Letters of credit and cash
Commodity-linked	0.50	August 2014	Letter of credit
Bilateral	0.55	September 2014	Letters of credit
Bilateral	0.25	December 2014	Letters of credit and cash
Bilateral	0.25	June 2014	Letters of credit and cash
Bilateral	0.15	September 2013	Letters of credit
Total	$4.02		

(1) *Facility size was reduced from $3.85 billion to $2.32 billion as a result of the completion of the transaction with EDF.*

Collectively, these facilities currently support the issuance of letters of credit and/or cash borrowings up to $4.0 billion. At December 31, 2009, we had approximately $1.7 billion in letters of credit issued and no commercial paper outstanding under these facilities.

The commodity-linked credit facility currently allows for the issuance of letters of credit up to a maximum capacity of $0.5 billion. This commodity-linked facility is designed to help manage our contingent collateral requirements associated with the hedging of our Customer Supply operations because its capacity increases as natural gas price levels decrease compared to a reference price that is adjusted periodically. As of December 31, 2009, there were no letters of credit outstanding under this facility.

BGE

BGE has a $575.0 million revolving credit facility expiring in 2011. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. The size of the facility may be increased up to $600 million with additional commitments by lenders. At December 31, 2009, BGE had $46.0 million in commercial paper outstanding with a weighted average effective interest rate of 0.39%. There were immaterial letters of credit outstanding at December 31, 2009.

Net Available Liquidity

The following table provides a summary of our net available liquidity at December 31, 2009:

	As of December 31, 2009		
	Constellation Energy	BGE	Total Consolidated
	(In billions)		
Credit facilities (1)	$ 3.5	$0.6	$ 4.1
Less: Letters of credit issued	(1.7)	—	(1.7)
Less: Cash drawn on credit facilities	—	—	—
Undrawn facilities	1.8	0.6	2.4
Less: Commercial paper outstanding	—	—	—
Net available facilities	1.8	0.6	2.4
Add: Cash	3.4	—	3.4
Less: Reserved cash (2)	(1.3)	—	(1.3)
Cash and facility liquidity	3.9	0.6	4.5
Add: EDF put arrangement	1.1	—	1.1
Net available liquidity	$ 5.0	$0.6	$ 5.6

(1) *Excludes commodity-linked credit facility due to its contingent nature.*

(2) *Represents management's expectation of payments to be made for income taxes and bond repurchases in the first quarter of 2010.*

Other Sources of Liquidity

In December 2008, we executed an Investment Agreement with EDF that includes an asset put arrangement that provides us with an option at any time through December 31, 2010 to sell certain non-nuclear generation assets, at pre-agreed prices, to EDF for aggregate proceeds of no more than $2 billion pre-tax, or approximately $1.4 billion after-tax. The amount of after-tax proceeds will be impacted by the assets actually sold and the related tax impacts at that time.

Exercise of the put arrangement is conditioned upon the receipt of regulatory approvals and third party consents, the absence of any material liens on such assets, and the absence of a material adverse effect, as defined in the Investment Agreement. During April 2009, we received regulatory approvals and consents for the majority of the assets covered by the put arrangement. As of December 31, 2009, we have approximately $1.1 billion after-tax of liquidity available through the put arrangement. We expect to receive regulatory approval for an additional asset in the second quarter of 2010, which will increase the net after-tax liquidity from the put arrangement to approximately $1.4 billion.

We believe that the actions that we have taken and our current net available liquidity will be sufficient to support our ongoing liquidity requirements. Our liquidity projections include assumptions for commodity price changes, which are subject to significant volatility, and we are exposed to certain operational risks that could have a significant impact on our liquidity.

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses, none of which would prohibit draws under the existing facilities.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2009, the debt to capitalization ratio as defined in the credit agreements was 34%.

Under our $2.32 billion credit facility, we granted a lien on certain of our generating facilities and pledged our ownership interests in our nuclear business to the lenders upon the completion of the transaction with EDF.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2009, the debt to capitalization ratio for BGE as defined in this credit agreement was 45%.

Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities. However, the impact of a credit ratings downgrade on our financial ratios associated with our credit facility covenants would depend on our financial condition at the time of such a downgrade and on the source of funds used to satisfy the incremental collateral obligation resulting from a credit ratings downgrade. For example, if we were to use existing cash balances or exercise the put option with EDF to fund the cash portion of any additional collateral obligations resulting from a credit ratings downgrade, we would not expect a material impact on our financial ratios. However, if we were to issue long-term debt or use our credit facilities to fund any additional collateral obligations, our financial ratios could be materially affected. Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the borrowings outstanding and preclude us from issuing letters of credit under these facilities.

9 Capitalization

We detail in the table below our total capitalization, which includes long-term debt, common stock, noncontrolling interests, and preference stock, as of December 31, 2009 and 2008.

At December 31,	**2009**	2008
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
Zero Coupon Senior Notes, due June 19, 2023	**$ —**	$ 256.7
8.625% Series A Junior Subordinated Debentures, due June 15, 2063	**450.0**	450.0
8% Series B Mandatorily Redeemable Preferred Stock	**—**	1,000.0
14% Senior Notes, due December 31, 2009	**—**	1,000.0
6.125% Fixed-Rate Notes, due September 1, 2009	**—**	500.0
7.00% Fixed-Rate Notes, due April 1, 2012	**700.0**	700.0
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**38.6**	55.9
Total long-term debt of Constellation Energy	**2,438.6**	5,212.6
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Port facilities loan, due June 1, 2013	**—**	10.0
4.10% Pollution control loan, due July 1, 2014	**20.0**	20.0
Floating-rate pollution control loan, due June 1, 2027	**—**	8.8
Tax-exempt variable rate notes, due April 1, 2024	**75.0**	75.0
Tax-exempt variable rate notes, due December 1, 2025	**47.0**	47.0
Tax-exempt variable rate notes, due December 1, 2037	**65.0**	65.0
District Cooling facilities loan, due December 1, 2031	**—**	25.0
5.00% Mortgage note, due June 15, 2010	**0.4**	1.6
4.25% Mortgage note, due March 15, 2009	**—**	0.2
7.3% Fixed Rate Note, due June 1, 2012	**1.7**	1.8
Asset-based lending agreement due July 16, 2012	**27.1**	—
Total long-term debt of nonregulated businesses	**236.2**	254.4
Other long-term debt of BGE		
6.125% Notes, due July 1, 2013	**400.0**	400.0
5.90% Notes, due October 1, 2016	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
6.35% Notes, due October 1, 2036	**400.0**	400.0
Medium-term notes, Series E	**131.5**	143.0
Total other long-term debt of BGE	**1,431.5**	1,443.0
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Rate stabilization bonds	**510.9**	564.4
Unamortized discount and premium	**(4.0)**	(41.9)
Current portion of long-term debt	**(56.9)**	(2,591.5)
Total long-term debt	**$ 4,814.0**	$ 5,098.7

At December 31,	2009	2008
	(In millions)	
Equity:		
Noncontrolling Interests	**$ 75.3**	$ 20.1
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $101.42 per share until June 30, 2010, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $101.39 per share until September 30, 2010, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $101.68 per share until December 31, 2010, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $102.10 per share until September 30, 2010, and at lesser amounts thereafter	**60.0**	60.0
Total BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 600,000,000 shares authorized; 200,985,414 and 199,128,908 shares issued and outstanding at December 31, 2009 and 2008, respectively. (At December 31, 2009, 5,790,545 shares were reserved for the long-term incentive plans, 7,041,111 shares were reserved for the shareholder investment plan, and 527,959 shares were reserved for the employee savings plan.)	**3,229.6**	3,164.5
Retained earnings	**6,461.0**	2,228.7
Accumulated other comprehensive loss	**(993.5)**	(2,211.8)
Total common shareholders' equity	**8,697.1**	3,181.4
Total Equity	**8,962.4**	3,391.5
Total Capitalization	**$13,776.4**	$ 8,490.2

Long-term Debt

Long-term debt matures in one year or more from the date of issuance. The long-term debt of Constellation Energy and BGE do not contain material adverse change clauses. We detail our long-term debt in the table above.

Constellation Energy

Mandatorily Redeemable Series B Preferred Stock

On December 17, 2008, Constellation Energy entered into an Investment Agreement with EDF. Simultaneously with the execution of the Investment Agreement, Constellation Energy issued 10,000 shares of 8% Series B Preferred Stock (Series B Preferred Stock) to EDF for $1 billion, which was restricted for the repayment of our 14% Senior Notes. On November 6, 2009, the date EDF completed the purchase of the 49.99% interest in CENG pursuant to the Investment Agreement, EDF surrendered to Constellation Energy all of the shares of the Series B Preferred Stock as partial payment for the purchase of the interest in CENG.

Upstream Gas Property Asset-Based Lending Agreement

In July 2009, we entered into a three year asset-based lending agreement associated with certain upstream gas properties that we own. At December 31, 2009, the borrowing base committed under the facility was $100 million, of which $27.1 million has been utilized and reflected in "Long-term debt" in our Consolidated Balance Sheets. The size of the facility may be increased up to $200 million with additional commitments by the lenders. Any debt issued under this facility is secured by the upstream gas properties, and the lenders do not have recourse against Constellation Energy in the event of a default. Interest is payable quarterly in March, June, September, and December.

This asset-based lending agreement contains a provision that requires certain of our entities that own our upstream gas properties to maintain a current ratio of one-to-one. As of December 31, 2009, these entities were in compliance with this provision.

Voluntary Debt Retirements

The repurchase of the following notes is part of our previously announced commitment to repay $1 billion of debt following the close of our transaction with EDF in November 2009.

Zero Coupon Senior Notes

In November 2009, we redeemed an aggregate principal amount of $267.6 million for the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million. We recorded the loss within "Interest expense" in the Consolidated Statements of Income (Loss).

Cash Tender Offer for Outstanding 7.00% Notes due April 1, 2012

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 pursuant to a cash tender offer, at a premium of approximately 11%.

Tax-Exempt Notes
During 2009, we retired approximately $150 million of variable rate tax exempt notes prior to maturity. On February 15, 2010, we issued a notice to call our outstanding $47 million and $65 million variable rate tax-exempt notes. These notes are expected to be repurchased on March 10, 2010. Since these notes are variable rate instruments, we do not expect to record any gain or loss upon repurchase.

BGE
Secured Indenture
BGE entered into a secured indenture in July 2009. The secured indenture creates a first priority lien on substantially all of BGE's electric utility distribution equipment and fixtures and on BGE's franchises, permits, and licenses that are transferable and necessary for the operation of the equipment and fixtures. As of December 31, 2009, BGE has not issued any secured bonds under this indenture.

BGE's Rate Stabilization Bonds
In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail in *Note 4*. Below are the details of the rate stabilization bonds at December 31, 2009:

Principal	Interest Rate	Scheduled Maturity Date
$171.7	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

The bonds are secured primarily by a usage-based, non-bypassable charge payable by all of BGE's residential electric customers over a ten year period. The charges will be adjusted semi-annually to ensure that the aggregate charges collected are sufficient to pay principal and interest on the bonds, as well as certain on-going costs of administering and servicing the bonds. BondCo cannot use the charges collected to satisfy any other obligations. BondCo's assets are not assets of any affiliate and are not available to pay creditors of any affiliate of BondCo. If BondCo is unable to make principal and interest payments on the bonds, neither Constellation Energy, nor BGE, are required to make the payments on behalf of BondCo.

BGE's Other Long-Term Debt
On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our merchant energy business related to the transferred generating assets. At December 31, 2009, BGE remains contingently liable for the $20 million outstanding balance of this debt.

BGE's fixed-rate medium-term note, series E, outstanding at December 31, 2009 has a weighted average interest rate of 6.71%, maturing between 2011 and 2012.

BGE Deferrable Interest Subordinated Debentures
On November 21, 2003, BGE Capital Trust II (BGE Trust II), a Delaware statutory trust established by BGE, issued 10,000,000 Trust Preferred Securities for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 6.20%.

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time on or after November 21, 2008 or at any time when certain tax or other events occur.

BGE Trust II will use the interest paid on the 6.20% debentures to make distributions on the Trust Preferred Securities. The 6.20% debentures are the only assets of BGE Trust II.

BGE fully and unconditionally guarantees the Trust Preferred Securities based on its various obligations relating to the trust agreement, indentures, 6.20% debentures, and the preferred security guarantee agreement.

For the payment of dividends and in the event of liquidation of BGE, the 6.20% debentures are ranked prior to preference stock and common stock.

Loan Agreement
On December 18, 2001, BGE's subsidiary, District Chilled Water Partnership (ComfortLink) entered into a $25.0 million loan agreement with the Maryland Energy Financing Administration (MEFA). The terms of the loan exactly match the terms of variable rate, tax exempt bonds due December 1, 2031 issued by MEFA for ComfortLink to finance the cost of building a chilled water distribution system.

These bonds were repurchased in June 2009.

Maturities of Long-Term Debt
As of December 31, 2009, our long-term borrowings mature on the following schedule:

Year	Constellation Energy (1)	Nonregulated Businesses	BGE	Total
		(In millions)		
2010	$ —	$ 0.4	$ 56.5	$ 56.9
2011	—	0.1	81.7	81.8
2012	722.6	28.7	172.5	923.8
2013	—	—	466.6	466.6
2014	—	20.0	70.4	90.4
Thereafter	1,716.0	187.0	1,352.4	3,255.4
Total	$2,438.6	$236.2	$2,200.1	$4,874.9

(1) A portion of Constellation Energy's bonds will be retired in 2010 as discussed in the Voluntary Debt Retirements section.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt outstanding were:

At December 31,	**2009**	2008
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**4.50%**	2.61%
Tax-exempt debt	**1.22%**	3.17%
Fixed-rate debt converted to floating *	**2.30%**	4.88%

* *As discussed in Note 13, as of December 31, 2009, we have interest rate swaps relating to $400.0 million of our fixed-rate debt.*

Preference Stock

Each series of BGE preference stock has no voting power, except for the following:

- the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

Dividend Restrictions

Constellation Energy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends, except certain of our credit facilities prohibit us from increasing our common stock dividend without the consent of the lenders.

BGE

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.

10 Taxes

The components of income tax expense are as follows:

Year Ended December 31,	**2009**	2008	2007
	(Dollar amounts in millions)		
Income Taxes			
Current			
Federal	**$ 891.5**	$ 2.8	$168.2
State	**260.4**	48.1	40.6
Current taxes charged to expense	**1,151.9**	50.9	208.8
Deferred			
Federal	**1,474.5**	(101.6)	184.7
State	**372.5**	(21.2)	41.5
Deferred taxes charged (credited) to expense	**1,847.0**	(122.8)	226.2
Investment tax credit adjustments	**(12.1)**	(6.4)	(6.7)
Income taxes per Consolidated Statements of Income (Loss)	**$2,986.8**	$ (78.3)	$428.3

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
(Loss) Income from continuing operations before income taxes	**$7,490.2**	$(1,396.7)	$1,262.7
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**2,621.6**	(488.8)	441.9
Increases (decreases) in income taxes due to			
State income taxes, net of federal income tax benefit	**411.0**	17.3	53.4
Merger-related transaction costs	**(79.3)**	416.2	—
Interest expense on mandatorily redeemable preferred stock	**23.7**	7.8	—
Qualified decommissioning impairment loss	**3.1**	(28.5)	—
Amortization of deferred investment tax credits	**(12.1)**	(6.4)	(6.7)
Synthetic fuel tax credits flowed through to income	**—**	(4.5)	(166.2)
Estimated synthetic fuel tax credit phase-out	**—**	—	110.3
Nondeductible international losses	**19.2**	—	—
Other	**(0.4)**	8.6	(4.4)
Total income taxes	**$2,986.8**	$ (78.3)	$ 428.3
Effective income tax rate	**39.9%**	5.6%	33.9%

BGE's effective tax rate was 41.3% in 2009, 28.7% in 2008, and 40.7% in 2007. In general, the primary difference between BGE's effective tax rate and the 35% statutory federal income tax rate for all years relates to Maryland corporate income taxes, net of the related federal income tax benefit. The increase in BGE's effective tax rate in 2009 is primarily due to higher taxable income. For 2008, BGE had lower taxable income related to the 2008 Maryland settlement agreement, which increased the relative impact of favorable permanent tax adjustments on BGE's 2008 effective tax rate.

The major components of our net deferred income tax liability are as follows:

At December 31,	Constellation Energy 2009	Constellation Energy 2008	BGE 2009	BGE 2008
	(In millions)			
Deferred Income Taxes				
Deferred tax liabilities				
Net property, plant and equipment	**$1,474.6**	$1,432.5	**$ 920.1**	$604.4
Qualified nuclear decommissioning trust funds	**—**	310.9	**—**	—
Regulatory assets, net	**263.0**	295.5	**263.0**	295.5
Derivative assets and liabilities, net	**329.6**	310.6	**—**	—
Investment in CENG	**1,802.7**	—	**—**	—
Other	**33.1**	126.6	**(55.1)**	32.5
Total deferred tax liabilities	**3,903.0**	2,476.1	**1,128.0**	932.4
Deferred tax assets				
Asset retirement obligation	**7.9**	391.6	**—**	—
Defined benefit obligations	**311.7**	552.0	**(23.7)**	30.8
Financial investments and hedging instruments	**337.0**	949.7	**—**	—
Deferred investment tax credits	**13.0**	17.8	**3.8**	4.3
Other	**155.8**	156.0	**71.5**	13.8
Total deferred tax assets	**825.4**	2,067.1	**51.6**	48.9
Total deferred tax liability, net	**3,077.6**	409.0	**1,076.4**	883.5
Less: Current portion of deferred tax (asset)/liability	**(127.9)**	(268.0)	**(11.2)**	40.2
Long-term portion of deferred tax liability, net	**$3,205.5**	$ 677.0	**$1,087.6**	$843.3

Income Tax Audits

We file income tax returns in the United States and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for the years before 2005. In 2009, the IRS expanded its current audit of our consolidated federal income tax returns for the tax years 2005 through 2007 to include the 2008 tax year. Although the final outcome of the 2005-2008 IRS audit and future tax audits is uncertain, we believe that adequate provisions for income taxes have been made for potential liabilities resulting from such matters.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2009 and 2008 and our total unrecognized tax benefits at December 31, 2009 and 2008:

	2009	2008
	(In millions)	
Total unrecognized tax benefits, January 1	$189.7	$114.5
Increases in tax positions related to the current year	101.5	112.2
Increases in tax positions related to prior years	148.4	—
Reductions in tax positions related to prior years	(126.3)	(15.5)
Reductions in tax positions related to audit settlements	—	(21.5)
Reductions in tax positions as a result of a lapse of the applicable statute of limitations	(0.8)	—
Total unrecognized tax benefits, December 31 (1)	$312.5	$189.7

(1) BGE's portion of our total unrecognized tax benefits at December 31, 2009 and 2008 was $111.8 million and $4.8 million, respectively.

Increases in tax positions related to the current year are primarily due to unrecognized tax benefits related to state income tax accruals associated with the transaction to sell a 49.99% membership interest in CENG to EDF. Increases in tax positions related to prior years are primarily due to unrecognized tax benefits for BGE repair and depreciation deductions including a change of accounting method for tax return purposes for the 2008 tax year for which IRS consent was received in 2009 and which is currently subject to IRS examination. Reductions in prior year tax positions are primarily due to increased certainty in the deductibility of certain costs associated with the termination of our merger with MidAmerican as a result of the structure and sale of a 49.99% membership interest in CENG.

Total unrecognized tax benefits as of December 31, 2009 of $312.5 million include outstanding claims of approximately $65.8 million, including $52.2 million in state tax credits, for which no tax benefit was recorded on our Consolidated Balance Sheet because refunds were not received and the claims do not meet the "more-likely-than-not" threshold.

If the total amount of unrecognized tax benefits of $312.5 million were ultimately realized, our income tax expense would decrease by approximately $177 million. However, the $177 million includes state tax refund claims of approximately $52 million that have been disallowed by tax authorities and are subject to appeals. These state refund claims may be resolved by December 31, 2010. For this reason, we believe it is reasonably possible that reductions to our total unrecognized tax benefits of approximately $50 million may occur by December 31, 2010, although these reductions are not expected to materially impact income tax expense.

Interest and penalties recorded in our Consolidated Statements of Income (Loss) as tax expense (benefit) relating to liabilities for unrecognized tax benefits were as follows:

	For the Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Interest and penalties recorded as tax expense (benefit)	**$12.8**	$(0.4)	$4.7

BGE's portion of interest and penalties was immaterial for all years.

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $23.1 million, of which BGE's portion was $1.6 million at December 31, 2009, and $10.3 million, of which BGE's portion was $0.7 million, at December 31, 2008.

11 Leases

There are two types of leases—operating and capital. Capital leases qualify as sales or purchases of property and are reported in our Consolidated Balance Sheets. Our capital leases are not material in amount. All other leases are operating leases and are reported in our Consolidated Statements of Income (Loss). We expense all lease payments associated with our regulated business. Lease expense and future minimum payments for long-term, noncancelable, operating leases are not material to BGE's financial results. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease certain facilities and equipment. The lease agreements expire on various dates and have various renewal options. We also enter into certain power purchase agreements which are accounted for as operating leases. Under these agreements, we are required to make fixed capacity payments, as well as variable payments based on actual output of the plants. We record these payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We exclude from our future minimum lease payments table the variable payments related to the output of the plant due to the contingency associated with these payments.

Through June 2009, we also entered into time charter purchase agreements which entitled us to the use of dry bulk freight vessels in the management of our global coal and logistics services. Certain of these contracts must be accounted for as leases. During 2009 and 2008, we entered into time charter leases with terms ranging in duration from 1 to 60 months. These arrangements do not include provisions for material rent increases and do not have provisions for rent holidays, contingent rentals or other incentives. In 2009 and 2008, we recognized aggregate lease expense of approximately \$145 million and \$477 million, respectively, related to 31 and 49 dry bulk freight vessels, respectively, hired under time charter arrangements. The average term of these arrangements is approximately 3 months. We record the payments as "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss).

We recognized expense related to our operating leases as follows:

	Fuel and purchased energy expenses	Operating expenses	Total
		(In millions)	
2009	\$385.6	\$37.2	\$422.8
2008	664.8	38.0	702.8
2007	758.7	40.1	798.8

At December 31, 2009, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	Power Purchase Agreements	Other	Total
		(In millions)	
2010	\$ 194.5	\$ 31.5	\$ 226.0
2011	202.1	28.8	230.9
2012	178.5	25.7	204.2
2013	166.3	24.5	190.8
2014	161.5	22.7	184.2
Thereafter	333.8	62.6	396.4
Total future minimum lease payments	\$1,236.7	\$195.8	\$1,432.5

Sub-Lease Arrangements

We provide time charters of dry bulk freight vessels as part of the logistical services provided to our global customers that qualify as sub-leases of our time charter purchase contracts. In 2009 and 2008, we recorded sub-lease income of approximately \$114 million and \$289 million, respectively, related to our time charter sub-leases. We record sub-lease income as part of "Nonregulated revenues" in our Consolidated Statements of Income (Loss). As of December 31, 2009, the future minimum rentals to be received for these time charters are shown below:

Year	Time Charter Sub-Leases
	(In millions)
2010	\$ 56.5
2011	56.6
2012	45.5
2013	32.0
2014	24.3
Thereafter	114.8
Total future minimum lease rentals	\$329.7

12 Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our merchant energy, regulated electric and gas, and other nonregulated businesses. These commitments relate to:

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of energy to meet our obligations to our customers, and
- long-term service agreements, capital for construction programs, and other.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2010 and 2018. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2010 and 2030.

Our merchant energy business also has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated electric business enters into various long-term contracts for the procurement of electricity. As of December 31, 2009, these contracts expire between 2010 and 2012 and represent BGE's estimated requirements as follows:

Contract Duration	*Percentage of Estimated Requirements*
From January 1, 2010 to September 2010	100%
From October 2010 to May 2011	75
From June 2011 to September 2011	50
From October 2011 to May 2012	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland PSC.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire between 2010 and 2011, and transportation and storage contracts that expire between 2012 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1,* and therefore are excluded from the table later in this Note.

Our other nonregulated businesses have committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

We have also committed to long-term service agreements and other obligations related to our information technology systems.

At December 31, 2009, we estimate our future obligations to be as follows:

	Payments				
	2010	2011-2012	2013-2014	Thereafter	Total
	(In millions)				
Merchant Energy:					
Purchased capacity and energy	$ 160.9	$ 303.5	$ 107.7	$208.7	$ 780.8
Purchased energy from CENG (1)	534.7	1,513.3	2,249.8	—	4,297.8
Fuel and transportation	540.5	437.5	94.3	217.9	1,290.2
Long-term service agreements, capital, and other	12.9	7.8	4.9	6.7	32.3
Total merchant energy	1,249.0	2,262.1	2,456.7	433.3	6,401.1
Corporate and Other:					
Long-term service agreements, capital, and other	49.6	11.3	1.7	—	62.6
Regulated:					
Purchase obligations and other	15.4	20.2	—	—	35.6
Total future obligations	$1,314.0	$2,293.6	$2,458.4	$433.3	$6,499.3

(1) Represents the nominal amounts of payments made to CENG under our power purchase agreement. The total fair value at closing of $0.8 billion was recorded on our balance sheet in "Unamortized energy contract assets."

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2019 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2016 and provide for the sale of all or a portion of the actual output of certain of our power plants. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

Guarantees

Our guarantees do not represent incremental Constellation Energy obligations; rather they primarily represent parental guarantees of subsidiary obligations. The following table summarizes the maximum exposure by guarantor based on the stated limit of our outstanding guarantees:

At December 31, 2009	Stated Limit
	(In billions)
Constellation Energy guarantees	$10.1
BGE guarantees	0.3
Total guarantees	$10.4

At December 31, 2009, Constellation Energy had a total of $10.4 billion in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

- Constellation Energy guaranteed a face amount of $10.1 billion as follows:
  - $9.4 billion on behalf of our merchant energy subsidiaries to allow those subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $2 billion at December 31, 2009, which represents the total amount the parent company could be required to fund based on December 31, 2009 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.
  - $0.5 billion primarily on behalf of CENG's nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants. We recorded the fair value of $12.3 million for these guarantees on our Consolidated Balance Sheets.
  - $0.2 billion to its other nonregulated businesses.
- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II.

Contingencies

Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

Merger with MidAmerican

Beginning September 18, 2008, seven shareholders of Constellation Energy filed lawsuits in the Circuit Court for Baltimore City, Maryland challenging the then-pending merger with MidAmerican. Four similar suits were filed by other shareholders of Constellation Energy in the United States District Court for the District of Maryland.

The lawsuits claim that the merger consideration was inadequate and did not maximize value for shareholders, that the sales process leading up to the merger was flawed, and that unreasonable deal protection devices were agreed to in order to ward off competing bids. The federal lawsuits also assert that the conversion of the Preferred Stock issued to MidAmerican into debt is not permitted under Maryland law.

The termination of the MidAmerican merger renders moot the claims attempting to enjoin the merger with MidAmerican. One of the federal merger cases was voluntarily dismissed on December 31, 2008, and the other federal merger cases were dismissed as moot on May 27, 2009. Plaintiffs' counsel in six of the seven state merger cases have filed dismissals without prejudice of their MidAmerican merger claims. In addition, on October 27, 2009 certain counsel in the state merger cases jointly moved for approval of a settlement regarding claims for attorneys' fees, which the court approved on November 16, 2009. We believe there are meritorious defenses to any claims or requests for relief that might possibly remain regarding this matter.

Securities Class Action

Three federal securities class action lawsuits have been filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation Energy between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation Energy, a number of its present or former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation Energy's June 27, 2008 offering of Debentures. The securities class actions also allege that Constellation Energy issued false or misleading statements or was aware of material undisclosed information which contradicted public statements including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions seek, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed there to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. We are unable at this time to determine the ultimate outcome of the securities class actions or their possible effect on our, or BGE's financial results.

ERISA Actions

In the fall of 2008, multiple class action lawsuits were filed in the United States District Courts for the District of Maryland and the Southern District of New York against Constellation

Energy; Mayo A. Shattuck III, Constellation Energy's Chairman of the Board, President and Chief Executive Officer; and others in their roles as fiduciaries of the Constellation Energy Employee Savings Plan. The actions, which have been consolidated into one action in Maryland (the Consolidated Action), allege that the defendants, in violation of various sections of ERISA, breached their fiduciary duties to prudently and loyally manage Constellation Energy Savings Plan's assets by designating Constellation Energy common stock as an investment, by failing to properly provide accurate information about the investment, by failing to avoid conflicts of interest, by failing to properly monitor the investment and by failing to properly monitor other fiduciaries. The plaintiffs seek to compel the defendants to reimburse the plaintiffs and the Constellation Energy Savings Plan for all losses resulting from the defendants' breaches of fiduciary duty, to impose a constructive trust on any unjust enrichment, to award actual damages with pre- and post-judgment interest, to award appropriate equitable relief including injunction and restitution and to award costs and expenses, including attorneys' fees. On October 2, 2009, the defendants moved to dismiss the consolidated complaint in its entirety. We are unable at this time to determine the ultimate outcome of the Consolidated Action or its possible effects on our, or BGE's, financial results.

Mercury

Since September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical companies, manufacturers of vaccines, and manufacturers of Thimerosal have been sued. Approximately 70 cases, involving claims related to approximately 132 children, have been filed to date, with each claimant seeking $20 million in compensatory damages, plus punitive damages, from us.

The claims against BGE and Constellation Energy have been dismissed in all of the cases either with prejudice based on rulings by the Court or without prejudice based on voluntary dismissals by the plaintiffs' counsel. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Asbestos

Since 1993, BGE and certain Constellation Energy subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Constellation Energy knew of and exposed individuals to an asbestos hazard. In addition to BGE and Constellation Energy, numerous other parties are defendants in these cases.

Approximately 494 individuals who were never employees of BGE or Constellation Energy have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third party claims brought by other defendants may also be filed against BGE and Constellation Energy in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment and a small minority have been resolved for amounts that were not material to our financial results.

BGE and Constellation Energy do not know the specific facts necessary to estimate their potential liability for these claims. The specific facts we do not know include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors,
- the names of the plaintiffs' employers,
- the dates on which and the places where the exposure allegedly occurred, and
- the facts and circumstances relating to the alleged exposure.

Until the relevant facts are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Environmental Matters

Solid and Hazardous Waste

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the potentially responsible parties, including BGE, with respect to investigation of the site became effective. The settlement requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. BGE is indemnified by a wholly owned subsidiary of Constellation Energy for most of the costs related to this settlement and clean-up of the site. The clean-up costs will not be known until the investigation is closer to completion, which is expected by mid-2010. The completed investigation will provide a range of remediation alternatives to the EPA, and the EPA is expected to select one of the alternatives by the end of the first quarter of 2011. The clean-up costs we incur could have a material effect on our financial results.

Air Quality

In May 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the

Environment to resolve alleged violations of air quality opacity standards at three fossil fuel plants in Maryland. The consent decree requires the subsidiary to pay a $100,000 penalty, provide $100,000 to a supplemental environmental project, and install technology to control emissions from those plants.

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold an approximately 21% interest in the Keystone plant. The NOV alleges that the plant performed various capital projects beginning in 1984 without complying with the new source review permitting requirements of the Clean Air Act. The EPA also contends that the alleged failure to comply with those requirements are continuing violations under the plant's air permits. The EPA could seek civil penalties under the Clean Air Act for the alleged violations.

The owners and operator of the Keystone plant are investigating the allegations and have entered into discussions with the EPA. We believe there are meritorious defenses to the allegations contained in the NOV. However, we cannot predict the outcome of this proceeding and it is not possible to determine our actual liability, if any, at this time.

Water Quality

In October 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by our coal-fired plants. The consent decree requires the payment of a $1.0 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. We recorded a liability in our Consolidated Balance Sheets of approximately $8.4 million, which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, monitor groundwater conditions, and otherwise comply with the consent decree. We have paid approximately $4.8 million of these costs as of December 31, 2009, resulting in a remaining liability at December 31, 2009 of $3.6 million. We estimate that it is reasonably possible that we could incur additional costs of up to approximately $10 million more than the liability that we accrued.

Investment in CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF. As a result of the sale, we now hold a 50.01% interest in CENG. As a 50.01% owner in CENG, we are subject to certain capital contribution requirements, which may be greater than the amount planned and, therefore, could have an adverse impact on our financial results.

In addition, if the fair value of our investment in CENG declines to a level below our carrying value and the decline is considered other-than-temporary, we may write down the investment to fair value, which would adversely affect our financial results.

We are also exposed to the same risks to which CENG is exposed. CENG owns and operates three nuclear generating facilities and is exposed to risks associated with operating these facilities and the risks of a nuclear accident.

Operating Risks

The operation of nuclear generating facilities involve routine risks, including,

- mechanical or structural problems,
- inadequacy or lapses in maintenance protocols,
- cost of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel,
- regulatory actions, including shut down of units because of public safety concerns,
- limitations on the amounts and types of insurance coverage commercially available,
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities,
- terrorist attacks, and
- environmental risks.

Nuclear Accidents

CENG is required to insure itself against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $375 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment is $117.5 million per reactor, per incident, increasing the total amount of insurance for public liability to approximately $12.6 billion. Under the retrospective assessment program, CENG can be assessed up to $587.5 million per incident at any commercial reactor in the country, payable at no more than $87.5 million per incident per year. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed CENG's insurance coverage. As a result, uninsured losses or the payment of retrospective insurance premiums could each have a significant adverse impact to CENG's, and therefore, our financial results as a 50.01% owner in CENG. Each of Constellation Energy and EDF has guaranteed the obligations of CENG under these insurance programs in proportion to their respective membership interests.

Non-Nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Our conventional property insurance program also provides coverage for non-certified acts of terrorism up to an annual aggregate limit of $1.0 billion. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

13 Derivatives and Fair Value Measurements

Use of Derivative Instruments

Nature of Our Business and Associated Risks

Our business activities primarily include our merchant energy business and our regulated electric and gas business. Our merchant energy business includes:

- the generation of electricity from our owned and contractually-controlled physical assets,
- the sale of power, gas, and other energy commodities to wholesale and retail customers, and
- risk management services and energy trading activities.

Our regulated electric and gas businesses engage in electricity and gas transmission and distribution activities in Central Maryland at prices set by the Maryland PSC that are generally designed to recover our costs, including purchased fuel and energy. Substantially all of our risk management activities involving derivatives occur outside our regulated businesses.

In carrying out our merchant energy business activities, we purchase and sell power, fuel, and other energy-related commodities in competitive markets. These activities expose us to significant risks, including market risk from price volatility for energy commodities and the credit risks of counterparties with which we enter into contracts. The sources of these risks include, but are not limited to, the following:

- the risks of unfavorable changes in power prices in the wholesale forward and spot markets in which we sell a portion of the power from our power generation facilities and purchase power to meet our load-serving requirements,
- the risk of unfavorable fuel price changes for the purchase of a portion of the fuel for our generation facilities under short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs.
- the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power,
- interest rate risk associated with variable-rate debt and the fair value of fixed-rate debt used to finance our operations; and
- foreign currency exchange rate risk associated with international investments and purchases of equipment and commodities in currencies other than U.S. dollars.

Objectives and Strategies for Using Derivatives

Risk Management Activities

To lower our exposure to the risk of unfavorable fluctuations in commodity prices, interest rates, and foreign currency rates, we routinely enter into derivative contracts, such as fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges, for hedging purposes. The objectives for entering into such hedging transactions primarily include:

- fixing the price for a portion of anticipated future electricity sales from our generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- managing our exposure to interest rate risk and foreign currency exchange risks.

Non-Risk Management Activities

In addition to the use of derivatives for risk management purposes, we also enter into derivative contracts for trading purposes primarily for:

- optimizing the margin on surplus electricity generation and load positions and surplus fuel supply and demand positions,
- price discovery and verification, and
- deploying limited risk capital in an effort to generate returns.

Accounting for Derivative Instruments

The accounting requirements for derivatives require recognition of all qualifying derivative instruments on the balance sheet at fair value as either assets or liabilities.

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they are derivatives, for which there are several possible accounting treatments. Mark-to-market is required as the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. The permissible accounting treatments include:

- normal purchase normal sale (NPNS),
- cash flow hedge,
- fair value hedge, and
- mark-to-market.

We discuss our accounting policies for derivatives and hedging activities and their impacts on our financial statements in *Note 1.*

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we cannot subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting.

Cash Flow Hedging

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery activities because hedge accounting more closely aligns the timing of earnings recognition and cash flows for the underlying business activities. Management monitors the potential impacts of commodity price changes and, where appropriate, may enter into or close out (via offsetting transactions) derivative transactions designated as cash flow hedges.

Commodity Cash Flow Hedges

Our merchant energy business has designated fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2010 through 2016. Our merchant energy business had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $951.3 million at December 31, 2009 and $2,624.0 million at December 31, 2008.

We expect to reclassify $631.5 million of net pre-tax losses on cash-flow hedges from "Accumulated other comprehensive loss" into earnings during the next twelve months based on market prices at December 31, 2009. However, the actual amount reclassified into earnings could vary from the amounts recorded at December 31, 2009, due to future changes in market prices.

When we determine that a forecasted transaction originally hedged has become probable of not occurring, we reclassify net unrealized gains or losses associated with those hedges from "Accumulated other comprehensive loss" to earnings. We recognized in earnings the following pre-tax amounts on such contracts:

Year ended December 31,	**2009**	2008	2007
		(In millions)	
Pre-tax losses	**$(241.0)**	$(31.7)	$(24.4)

The pre-tax loss reclassified in 2009 resulted from the sale of a majority of our international commodities operation and our termination of certain contracts as part of our efforts to improve liquidity and reduce risk. The forecasted transactions associated with previously designated cash-flow hedge contracts were deemed probable of not occurring.

Interest Rate Swaps Designated as Cash Flow Hedges

We use interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances and to manage our exposure to fluctuations in interest rates on variable rate debt. The effective portion of gains and losses on these interest rate cash flow hedges, net of associated deferred income tax effects, is recorded in "Accumulated other comprehensive loss" in our Consolidated Statements of Comprehensive Income (Loss). We reclassify gains and losses on the hedges from "Accumulated other comprehensive loss" into "Interest expense" in our Consolidated Statements of Income (Loss) during the periods in which the interest payments being hedged occur.

Accumulated other comprehensive loss includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $11.3 million at December 31, 2009 and $12.0 million at December 31, 2008. We expect to reclassify $2.3 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive loss" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps and certain forward contracts and price and basis swaps associated with natural gas fuel in storage. The objectives for electing fair value hedging in these situations are to manage our exposure, to optimize the mix of our fixed and floating-rate debt, and to hedge the value of our natural gas in storage. We did not have any fair value hedges related to the value of our natural gas in storage during the last nine months of 2009.

Interest Rate Swaps Designated as Fair Value Hedges

We use interest rate swaps designated as fair value hedges to optimize the mix of fixed and floating-rate debt. We record any gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as changes in the fair value of the debt being hedged, in "Interest expense." We record changes in fair value of the swaps in "Derivative assets and liabilities" and changes in the fair value of the debt in "Long-term debt" in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in "Interest expense" in the periods that the swaps settle.

During 2004, we entered into interest rate swaps qualifying as fair value hedges relating to $450 million of our fixed-rate debt maturing in 2012 and 2015, and converted this notional amount of debt to floating-rate. On July 15, 2009, we terminated an interest rate swap relating to $50 million of the $450 million of our fixed-rate debt and received approximately $4.5 million in cash. The fair value of these hedges was an unrealized gain of $35.8 million at December 31, 2009 and $55.9 million at December 31, 2008 and was recorded as an increase in our "Derivative assets" and an increase in our "Long-term debt." We had no hedge ineffectiveness on these interest rate swaps.

Hedge Ineffectiveness

For all categories of derivative instruments designated in hedging relationships, we recorded in earnings the following pre-tax gains (losses) related to hedge ineffectiveness:

Year ended December 31,	**2009**	2008	2007
		(In millions)	
Cash-flow hedges	**$11.3**	$(121.0)	$(31.4)
Fair value hedges	**23.9**	20.6	24.4
Total	**$35.2**	$(100.4)	$ (7.0)

We did not recognize any gain or loss during 2009 and 2008 relating to changes in value for the portion of our fair value hedges excluded from our hedge effectiveness assessment.

Mark-to-Market

We generally apply mark-to-market accounting for risk management and trading activities for which changes in fair value more closely reflect the economic performance of the underlying business activity. However, we also use mark-to-market accounting for derivatives related to the following physical energy delivery activities:

- our nonregulated retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

Origination Gains

We may record origination gains associated with commodity derivatives subject to mark-to-market accounting. Origination gains represent the initial fair value of certain structured transactions that our wholesale marketing, risk management, and trading operation executes to meet the risk management needs of our customers. Historically, transactions that result in origination gains have been unique and resulted in individually significant gains from a single transaction. We generally recognize origination gains when we are able to obtain observable market data to validate that the initial fair value of the contract differs from the contract price. Origination gains recognized in the past three years include:

- none in 2009,
- $73.8 million pre-tax in 2008 resulting from 6 transactions, and
- $41.9 million pre-tax in 2007 resulting from 1 transaction.

Termination or Restructuring of Commodity Derivative Contracts

We may terminate or restructure in-the-money contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of contracts allows us to lower our exposure to performance risk under these contracts. Such transactions resulted in the realization of the following amounts of pre-tax earnings that otherwise would have been recognized over the life of these contracts:

- none in 2009,
- $73.1 million pre-tax in 2008 resulting from 7 transactions, and
- $17.8 million pre-tax in 2007 resulting from 1 transaction.

Quantitative Information About Derivatives and Hedging Activities

Background

Effective January 1, 2009, we adopted an accounting standard that addresses disclosures about derivative instruments and hedging activities. This standard does not change the accounting for derivatives; rather, it requires expanded disclosure about derivative instruments and hedging activities regarding:

- the ways in which an entity uses derivatives,
- the accounting for derivatives and hedging activities, and
- the impact that derivatives have (or could have) on an entity's financial position, financial performance, and cash flows.

Balance Sheet Tables

We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis, including cash collateral, whenever we have a legally enforceable master netting agreement with a counterparty to a derivative contract. We use master netting agreements whenever possible to manage and substantially reduce our potential counterparty credit risk. The net presentation in our Consolidated Balance Sheets reflects our actual credit exposure after giving effect to the beneficial effects of these agreements and cash collateral, and our credit risk is reduced further by other forms of collateral.

The following table provides information about the types of market risks we manage using derivatives. This table only includes derivatives and does not reflect the price risks we are hedging that arise from physical assets or nonderivative accrual contracts within our generating plants, customer supply, and global commodities activities.

As discussed more fully following the table, we present this information by disaggregating our net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to the risk-reducing benefits of master netting arrangements and collateral. As a result, we must present each individual contract as an "asset value" if it is in the money or a "liability value" if it is out of the money, regardless of whether the individual contracts offset market or credit risks of other contracts in full or in part. Therefore, the gross amounts in this table do not reflect our actual economic or credit risk associated with derivatives. This gross presentation is intended only to show separately the various derivative contract types we use, such as commodities, interest rate, and foreign exchange.

In order to identify how our derivatives impact our financial position, at the bottom of the table we provide a reconciliation of the gross fair value components to the net fair value amounts as presented in the *Fair Value Measurements* section of this note and our Consolidated Balance Sheets.

The gross asset and liability values in the table below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships. Derivatives not designated in hedging relationships include our retail gas customer supply operation, economic hedges of accrual activities, the total return swaps entered into to effect the sale of the international commodities and Houston-based gas trading operations, and risk management and trading activities which we have substantially curtailed as part of our effort to reduce risk in our business. We use the end of period accounting designation to determine the classification for each derivative position.

As of December 31, 2009	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	Asset Values (3)	Liability Values (4)	Asset Values (3)	Liability Values (4)	Asset Values (3)	Liability Values (4)
			(In millions)			
Power contracts	$1,737.3	$(2,292.1)	$11,729.3	$(12,414.3)	$ 13,466.6	$(14,706.4)
Gas contracts	1,860.6	(1,380.0)	4,159.1	(3,857.1)	6,019.7	(5,237.1)
Coal contracts	20.1	(40.8)	609.5	(627.2)	629.6	(668.0)
Other commodity contracts (1)	1.4	(0.8)	83.1	(32.1)	84.5	(32.9)
Interest rate contracts	35.8	—	28.5	(39.9)	64.3	(39.9)
Foreign exchange contracts	—	—	13.2	(9.0)	13.2	(9.0)
Total gross fair values	$3,655.2	$(3,713.7)	$16,622.7	$(16,979.6)	$ 20,277.9	$(20,693.3)
Netting arrangements (5)					(19,261.0)	19,261.0
Cash collateral					(92.6)	125.6
Net fair values					$ 924.3	$ (1,306.7)
Net fair value by balance sheet line item:						
Accounts receivable (2)					$ (348.7)	
Derivative assets—current					639.1	
Derivative assets—noncurrent					633.9	
Derivative liabilities—current						(632.6)
Derivative liabilities—noncurrent						(674.1)
Total Derivatives					$ 924.3	$ (1,306.7)

(1) *Other commodity contracts include oil, freight, emission allowances, and weather contracts.*

(2) *Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.*

(3) *Represents in-the-money contracts without regard to potentially offsetting out-of-the-money contracts under master netting agreements.*

(4) *Represents out-of-the-money contracts without regard to potentially offsetting in-the-money contracts under master netting agreements.*

(5) *Represents the effect of legally enforceable master netting agreements.*

The magnitude of and changes in the gross derivatives components in this table do not indicate changes in the level of derivative activities, the level of market risk, or the level of credit risk. The primary factors affecting the magnitude of the gross amounts in the table are changes in commodity prices and the total number of contracts. If commodity prices change, the gross amounts could increase, even if the level of contracts stays the same, because separate presentation is required for contracts that are in the money from those that are out of the money. As a result, the gross amounts of even fully hedged positions could increase if prices change. Additionally, if the number of contracts increases, the gross amounts also could increase. Thus, the execution of new contracts to reduce economic risk could actually increase the gross amounts in the table because of the requirement to present the gross value of each individual contract separately.

The primary purpose of this table is to disaggregate the risks being managed using derivatives. In order to achieve this objective, we prepare this table by separating each individual derivative contract that is in the money from each contract that is out of the money and present such amounts on a gross basis, even for offsetting contracts that have identical quantities for the same commodity, location, and delivery period. We must also present these components excluding the substantive credit-risk reducing effects of master netting agreements and collateral. As a result, the gross "asset" and "liability" amounts for each contract type far exceed our actual economic exposure to commodity price risk and credit risk. Our actual economic exposure consists of the net derivative position combined with our nonderivative accrual contracts, such as those for load-serving, and our physical assets, such as our power plants. Our actual derivative credit risk exposure after master netting agreements and cash collateral is reflected in the net fair value amounts shown at the bottom of the table above. Our total economic and credit exposures, including derivatives, are managed in a comprehensive risk framework that includes risk measures such as economic value at risk, stress testing, and maximum potential credit exposure.

Gain and (Loss) Tables

The tables below summarize the gain and loss impacts of our derivative instruments segregated into the following categories:

- cash flow hedges,
- fair value hedges, and
- mark-to-market derivatives.

The tables only include this information for derivatives and do not reflect the related gains or losses that arise from generation and generation-related assets, nonderivative accrual contracts, or NPNS contracts within our Generation, Customer Supply, and Global Commodities activities, other than fair value hedges, for which we separately show the gain or loss on the hedged asset or liability. As a result, for mark-to-market and cash-flow hedge derivatives, these tables only reflect the impact of derivatives themselves and therefore do not necessarily include all of the income statement impacts of the transactions for which derivatives are used to manage risk. For a more complete discussion of how derivatives affect our financial performance, see our accounting policy for Revenues, Fuel and Purchased Energy Expenses, and Derivatives and Hedging Activities in *Note 1*.

The following table presents gains and losses on derivatives designated as cash flow hedges. As discussed more fully in our accounting policy, we record the effective portion of unrealized gains and losses on cash flow hedges in Accumulated Other Comprehensive Loss until the hedged forecasted transaction affects earnings. We record the ineffective portion of gains and losses on cash flow hedges in earnings as they occur. When the hedged forecasted transaction settles and is recorded in earnings, we reclassify the related amounts from Accumulated Other Comprehensive Loss into earnings, with the result that the combination of revenue or expense from the forecasted transaction and gain or loss from the hedge are recognized in earnings at a total amount equal to the hedged price. Accordingly, the amount of derivative gains and losses recorded in Accumulated Other Comprehensive Loss and reclassified from Accumulated Other Comprehensive Loss into earnings does not reflect the total economics of the hedged forecasted transactions. The total impact of our forecasted transactions and related hedges is reflected in our Consolidated Statements of Income (Loss).

Cash Flow Hedges				*Year Ended December 31, 2009*
	Gain (Loss) Recorded in AOCI			
Contract type:	Year Ended December 31, 2009	Statement of Income (Loss) Line Item	Gain (Loss) Reclassified from AOCI into Earnings	Ineffectiveness Gain (Loss) Recorded in Earnings
		(In millions)		
Hedges of forecasted sales:		Nonregulated revenues		
Power contracts	$ 362.5		$ (180.6)	$ 77.5
Gas contracts	(65.1)		(67.3)	6.3
Coal contracts	10.0		(229.9)	—
Other commodity contracts (1)	6.8		(0.4)	(6.2)
Interest rate contracts	(0.3)		(0.3)	—
Foreign exchange contracts	2.5		(1.1)	—
Total gains (losses)	$ 316.4	Total included in nonregulated revenues	$ (479.6)	$ 77.6
Hedges of forecasted purchases:		Fuel and purchased energy expense		
Power contracts	$(1,056.0)		$(1,905.3)	$(42.2)
Gas contracts	103.7		165.8	(15.2)
Coal contracts	(77.7)		(187.6)	(8.9)
Other commodity contracts (2)	(12.3)		8.2	—
Foreign exchange contracts	—		—	—
Total losses	$(1,042.3)	Total included in fuel and purchased energy expense	$(1,918.9)	$(66.3)
Hedges of interest rates:		Interest expense		
Interest rate contracts	—		0.6	—
Total gains	$ —	Total included in interest expense	$ 0.6	$ —
Grand total (losses) gains	$ (725.9)		$(2,397.9)	$ 11.3

(1) Other commodity sale contracts include oil and freight contracts.

(2) Other commodity purchase contracts include freight and emission allowances.

The following table presents gains and losses on derivatives designated as fair value hedges and, separately, the gains and losses on the hedged item. As discussed earlier, we record the unrealized gains and losses on fair value hedges as well as changes in the fair value of the hedged asset or liability in earnings as they occur. The difference between these amounts represents hedge ineffectiveness. Due to the sale of our Houston-based gas trading operation, we do not have any activity under fair value hedges related to gas contracts since the second quarter of 2009.

Fair Value Hedges		*Year Ended December 31, 2009*	
Contract type:	Statement of Income (Loss) Line Item	Gain (Loss) Recognized in Income on Derivative	Gain (Loss) Recognized in Income on Hedged Item
		(In millions)	
Commodity contracts:			
Gas contracts	Nonregulated revenues	$40.6	$(16.7)
Interest rate contracts	Interest expense	(0.1)	0.7
Total gains (losses)		$40.5	$(16.0)

The following table presents gains and losses on mark-to-market derivatives, contracts that have not been designated as hedges for accounting purposes. As discussed more fully in *Note 1,* we record the unrealized gains and losses on mark-to-market derivatives in earnings as they occur. While we use mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity, we also use mark-to-market accounting for certain derivatives related to portions of our physical energy delivery activities. Accordingly, the total amount of gains and losses from mark-to-market derivatives does not necessarily reflect the total economics of related transactions.

Mark-to-Market Derivatives		*Year Ended December 31, 2009*
Contract type:	Statement of Income (Loss) Line Item	Gain (Loss) Recorded in Income on Derivative
		(In millions)
Commodity contracts:		
Power contracts	Nonregulated revenues	$ 250.9
Gas contracts	Nonregulated revenues	(360.0)
Coal contracts	Nonregulated revenues	14.0
Other commodity contracts (1)	Nonregulated revenues	(11.7)
Coal contracts	Fuel and purchased energy expense	(109.8)
Interest rate contracts	Nonregulated revenues	(27.2)
Foreign exchange contracts	Nonregulated revenues	7.6
Total gains (losses)		$(236.2)

(1) Other commodity contracts include oil, freight, emission allowances, weather, and uranium.

In computing the amounts of derivative gains and losses in the above tables, we include the changes in fair values of derivative contracts up to the date of maturity or settlement of each contract. This approach facilitates a comparable presentation for both financial and physical derivative contracts. In addition, for cash flow hedges we include the impact of intra-quarter transactions (i.e., those that arise and settle within the same quarter) in both gains and losses recognized in Accumulated Other Comprehensive Loss and amounts reclassified from Accumulated Other Comprehensive Loss into earnings.

Volume of Derivative Activity

The volume of our derivatives activity is directly related to the fundamental nature and scope of our business and the risks we manage. We own or control electric generating facilities, which exposes us to both power and fuel price risk; we serve electric and gas wholesale and retail customers within our customer supply business, which exposes us to electricity and natural gas price risk; and we provide risk management services and engage in trading activities, which can expose us to a variety of commodity price risks. We conduct our business activities throughout the United States and internationally. In order to manage the risks associated with these activities, we are required to be an active participant in the energy markets, and we routinely employ derivative instruments to conduct our business.

Derivative instruments provide an efficient and effective way to conduct our business and to manage the associated risks. We manage our generating resources and customer supply activities based upon established policies and limits, and we use derivatives to establish a portion of our hedges and to adjust the level of our hedges from time to time. Additionally, we engage in trading activities which enable us to execute hedging transactions in a cost-effective manner. We manage those activities based upon various risk measures, including position limits, economic value at risk (EVaR) and value at risk (VaR), and we use derivatives to establish and maintain those activities within the prescribed limits. We are also using derivatives to execute, control, and reduce the overall level of our trading positions and risk as well as to manage a portion of our interest rate risk associated with debt and our foreign currency risk from non-dollar denominated transactions. Accordingly, the use of derivative instruments is integral to the conduct of our business, and derivative instruments are an important tool through which we are able to manage and mitigate the risks that are inherent in our activities.

The following table presents information designed to provide insight into the overall volume of our derivatives usage. However, the volumes presented in this table are subject to a number of limitations and should only be used as an indication of the extent of our derivatives usage and the risks they are intended to manage.

First, the volume information is not a complete representation of our market price risk because it only includes derivative contracts. Accordingly, this table does not present a complete picture of our overall net economic exposure, and should not be interpreted as an indication of open or unhedged commodity positions, because the use of derivatives is only one of the means by which we engage in and manage the risks of our business. For example, the table does not include power or fuel quantities and risks arising from our physical assets, non-derivative contracts, and forecasted transactions that we manage using derivatives; a portion of these volumes reduce those risks. It also does not include volumes of commodities under nonderivative contracts that we use to serve customers or manage our risks. Our actual net economic exposure from our generating facilities and customer supply activities is reduced by derivatives, and the exposure from our trading activities is managed and controlled through the risk measures discussed above. Therefore, the information in the table below is only an indication of that portion of our business that we manage through derivatives and serves primarily to identify the extent of our derivatives activities and the types of risks that they are intended to manage.

Additionally, the disclosure of derivative quantities potentially could reveal commercially valuable or otherwise competitively sensitive information that could limit the effectiveness and profitability of our business activities. Therefore, in the table below, we have computed the derivative volumes for commodities by aggregating the absolute value of net positions within commodities for each year. This provides an indication of the level of derivatives activity, but it does not indicate either the direction of our position (long or short), or the overall size of our position. We believe this presentation gives an appropriate indication of the level of derivatives activity without unnecessarily revealing the size and direction of our derivatives positions.

Finally, the volume information for commodity derivatives represents "delta equivalent" quantities, not gross notional amounts. We make use of different types of commodity derivative instruments such as forwards, futures, options, and swaps, and we believe that the delta equivalent quantity is the most relevant measure of the volume associated with these commodity derivatives. The delta-equivalent quantity represents a risk-adjusted notional quantity for each contract that takes into account the probability that an option will be exercised. Therefore, the volume information for commodity derivatives represents the delta equivalent quantity of those contracts, computed on the basis described above. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the table below.

The following table presents the volume of our derivative activities as of December 31, 2009, shown by contractual settlement year.

Quantities (1) Under Derivative Contracts — *As of December 31, 2009*

Contract Type (Unit)	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Power (MWH)	32.7	1.6	3.2	3.2	0.1	0.9	41.7
Gas (mmBTU)	37.3	37.4	22.1	21.0	22.7	21.3	161.8
Coal (Tons)	3.9	3.9	0.2	—	—	—	8.0
Oil (BBL)	0.3	—	—	—	—	—	0.3
Emission Allowances (Tons)	7.2	—	—	—	—	—	7.2
Interest Rate Contracts	$972.3	$140.6	$440.5	$58.2	$255.0	$200.0	$2,066.6
Foreign Exchange Rate Contracts	$ 27.9	$ 72.4	$ 16.7	$16.7	$ 16.8	$ 15.5	$ 166.0

(1) *Amounts in the table are only intended to provide an indication of the level of derivatives activity and should not be interpreted as a measure of any derivative position or overall economic exposure to market risk. Quantities are expressed as "delta equivalents" on an absolute value basis by contract type by year. Additionally, quantities relate only to derivatives and do not include potentially offsetting quantities associated with physical assets and nonderivative accrual contracts.*

In addition to the commodities in the tables above, we also hold derivative instruments related to weather that are insignificant relative to the overall level of our derivative activity.

Credit-Risk Related Contingent Features

Certain of our derivative instruments contain provisions that would require additional collateral upon a credit-related event such as an adequate assurance provision or a credit rating decrease in the senior unsecured debt of Constellation Energy. The amount of collateral we could be required to post would be determined by the fair value of contracts containing such provisions that represent a net liability, after offset for the fair value of any asset contracts with the same counterparty under master netting agreements and any other collateral already posted. This collateral amount is a component of, and is not in addition to, the total collateral we could be required to post for all contracts upon a credit rating decrease.

The following table presents information related to these derivatives. Based on contractual provisions, we estimate that if Constellation Energy's senior unsecured debt were downgraded, our total contingent collateral obligation for derivatives in a net liability position was $0.2 billion as of December 31, 2009, which represents the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade. These amounts are associated with net derivative liabilities totaling $1.0 billion after reflecting legally binding master netting agreements and collateral already posted.

We present the gross fair value of derivatives in a net liability position that have credit-risk-related contingent features in the first column in the table below. This gross fair value amount represents only the out-of-the-money contracts containing such features that are not fully collateralized by cash on a stand-alone basis. Thus, this amount does not reflect the offsetting fair value of in-the-money contracts under legally-binding master netting agreements with the same counterparty, as shown in the second column in the table. These in-the-money contracts would offset the amount of any gross liability that could be required to be collateralized, and as a result, the actual potential collateral requirements would be based upon the net fair value of derivatives containing such features, not the gross amount. The amount of any possible contingent collateral for such contracts in the event of a downgrade would be further reduced to the extent that we have already posted collateral related to the net liability.

Because the amount of any contingent collateral obligation would be based on the net fair value of all derivative contracts under each master netting agreement, we believe that the "net fair value of derivative contracts containing this feature" as shown in the table below is the most relevant measure of derivatives in a net liability position with credit-risk-related contingent features. This amount reflects the actual net liability upon which existing collateral postings are computed and upon which any additional contingent collateral obligation would be based.

Credit-Risk Related Contingent Feature *As of December 31, 2009*

Gross Fair Value of Derivative Contracts Containing This Feature (1)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements (2)	Net Fair Value of Derivative Contracts Containing This Feature (3)	Amount of Posted Collateral (4)	Contingent Collateral Obligation (5)
		(In billions)		
$8.6	$(7.6)	$1.0	$0.7	$0.2

(1) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.

(2) Amount represents the offsetting fair value of in-the-money derivative contracts under legally-enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we potentially could be required to post collateral.

(3) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

(4) Amount includes cash collateral posted of $125.6 million and letters of credit of $585.2 million.

(5) Amounts represent the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Concentrations of Derivative-Related Credit Risk

We discuss our concentrations of credit risk, including derivative-related positions, in *Note 1 to the Consolidated Financial Statements*.

Fair Value Measurements

Effective January 1, 2008, we adopted guidance related to fair value measurements. This guidance defines fair value, establishes a framework for measuring fair value, and requires certain disclosures about fair value measurements. We discuss our fair value measurements below.

We determine the fair value of our assets and liabilities using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. We determine fair value for assets and liabilities classified as Level 1 by multiplying the market price by the quantity of the asset or liability. We primarily determine fair value measurements classified as Level 2 or Level 3 using the income valuation approach, which involves discounting estimated cash flows using assumptions that market participants would use in pricing the asset or liability.

We present all derivatives recorded at fair value net with the associated fair value cash collateral. This presentation of the net position reflects our credit exposure for our on-balance sheet positions but excludes the impact of any off-balance sheet positions and collateral. Examples of off-balance sheet positions and collateral include in-the-money accrual contracts for which the right of offset exists in the event of default and letters of credit. We discuss our letters of credit in more detail in *Note 8*.

Recurring Measurements

BGE's assets and liabilities measured at fair value on a recurring basis are immaterial. Our merchant energy business segment's assets and liabilities measured at fair value on a recurring basis consist of the following:

	As of December 31, 2009	
	Assets	Liabilities
	(In millions)	
Cash equivalents	$3,065.4	$ —
Equity securities	46.2	—
Derivative instruments:		
Classified as derivative assets and liabilities:		
Current	639.1	(632.6)
Noncurrent	633.9	(674.1)
Total classified as derivative assets and liabilities	1,273.0	(1,306.7)
Classified as accounts receivable*	(348.7)	—
Total derivative instruments	924.3	(1,306.7)
Total recurring fair value measurements	$4,035.9	$(1,306.7)

* *Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.*

Cash equivalents represent exchange-traded money market funds which are included in "Cash and cash equivalents" in the Consolidated Balance Sheets. Equity securities primarily represent mutual fund investments which are included in "Other assets" in the Consolidated Balance Sheets. Derivative instruments represent unrealized amounts related to all derivative positions, including futures, forwards, swaps, and options. We classify exchange-listed contracts as part of "Accounts Receivable" in our Consolidated Balance Sheets. We classify the remainder of our derivative contracts as "Derivative assets" or "Derivative liabilities" in our Consolidated Balance Sheets.

The table below disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis. Each individual asset or liability that is remeasured at fair value on a recurring basis is required to be presented in this table and classified, in its entirety, within the appropriate level in the fair value hierarchy. Therefore, the objective of this table is to provide information about how each individual derivative contract is valued within the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts or whether it has been collateralized.

The tables below set forth by level within the fair value hierarchy the gross components of the Company's assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2009. These gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either our actual credit exposure or net economic exposure.

At December 31, 2009	Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
			(In millions)		
Cash equivalents	$3,065.4	$ —	$ —	$ —	$ 3,065.4
Equity securities—mutual funds	46.2	—	—	—	46.2
Derivative assets	80.7	19,393.9	803.3	(19,353.6)	924.3
Derivative liabilities	(79.0)	(19,519.5)	(1,094.8)	19,386.6	(1,306.7)
Net derivative position	1.7	(125.6)	(291.5)	33.0	(382.4)
Total	$3,113.3	$ (125.6)	$ (291.5)	$ 33.0	$ 2,729.2

* *We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At December 31, 2009, we included $92.6 million of cash collateral held and $125.6 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.*

The factors that cause changes in the gross components of the derivative amounts in the tables above are unrelated to the existence or level of actual market or credit risk from our operations. We describe the primary factors that change the gross components below.

We prepared this table by separating each individual derivative contract that is in the money from each contract that is out of the money. We also did not reflect master netting agreements and collateral for our derivatives. As a result, the gross "asset" and "liability" amounts in each of the three fair value levels far exceed our actual economic exposure to commodity price risk and credit risk. Our actual economic exposure consists of the net derivative position combined with our nonderivative accrual contracts, such as those for load-serving, and our physical assets, such as our power plants. Our actual credit risk exposure is reflected in the net derivative asset and derivative liability amounts shown in the Total Net Fair Value column.

Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices and the total number of contracts. If commodity prices change, the gross amounts could increase, even if the level of contracts stays the same, because separate presentation is required for contracts that are in the money from those that are out of the money. As a result, even fully hedged positions could exhibit increases in the gross amounts if prices change. Additionally, if the number of contracts increases, the gross amounts also could increase. Thus, the execution of new contracts to reduce economic risk could actually increase the gross amounts in the table because of the required separation of contracts discussed above.

Cash equivalents consist of exchange-traded money market funds, which are valued based upon unadjusted quoted prices in active markets and are classified within Level 1.

Equity securities consist of mutual funds, which are valued based upon unadjusted quoted prices in active markets and are classified within Level 1.

Derivative instruments include exchange-traded and bilateral contracts. Exchange-traded derivative contracts include futures and certain options. Bilateral derivative contracts include swaps, forwards, certain options and structured transactions. We utilize models to measure the fair value of bilateral derivative contracts. Generally, we use similar models to value similar instruments. Valuation models utilize various inputs, which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs, which are inputs derived principally from or corroborated by observable market data by correlation or other means. However, the primary input to our valuation models is the forward commodity price. We have classified derivative contracts within the fair value hierarchy as follows:

- Exchange-traded derivative contracts valued based on unadjusted quoted prices in active markets are classified within Level 1.
- Exchange-traded derivative contracts valued using pricing inputs based upon market quotes or market transactions are classified within Level 2. These contracts generally trade in less active markets due to the length of the contracts (i.e., for certain contracts the exchange sets the closing price, which may not be reflective of an actual trade).
- Bilateral derivative contracts where observable inputs are available for substantially the full term and value of the asset or liability are classified within Level 2.
- Bilateral derivative contracts with a lower availability of pricing information are classified in Level 3. In addition, structured transactions, such as certain options, may require us to use internally-developed model inputs, which might not be observable in or corroborated by the market, to determine fair value. When such unobservable inputs have more than an insignificant impact on the measurement of fair value, we also classify the instrument within Level 3.

In order to determine fair value, we utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include:

- forward commodity prices,
- price volatility,
- volumes,
- location,
- interest rates,
- credit quality of counterparties and Constellation Energy, and
- credit enhancements.

We also record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of derivative assets and liabilities. The effect of these uncertainties is not incorporated in market price information or other market-based estimates used to determine fair value of our mark-to-market energy contracts. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

We describe below the main types of valuation adjustments we record and the process for establishing each. Generally, increases in valuation adjustments reduce our earnings, and decreases in valuation adjustments increase our earnings. However, all or a portion of the effect on earnings of changes in valuation adjustments may be offset by changes in the value of the underlying positions.

- Close-out adjustment—represents the estimated cost to close out or sell to a third party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.
- Unobservable input valuation adjustment—this adjustment is necessary when we determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information. Unobservable inputs to fair value may arise due to a number of factors, including but not limited to, the term of the transaction, contract optionality, delivery location, or product type. In the absence of observable market information that supports the model inputs, there is a presumption that the transaction price is equal to the market value of the contract when we transact in our principal market and thus we recalibrate our estimate of fair value to equal the transaction price. Therefore we do not recognize a gain or loss at contract inception on these transactions. We will recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.
- Credit-spread adjustment—for risk management purposes, we compute the value of our derivative assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our derivative assets to reflect the credit-worthiness of each counterparty based upon either published credit ratings, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying a default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve. As part of our evaluation, we assess whether the counterparties' published credit ratings are reflective of current market conditions. We review available observable data including bond prices and yields and credit default swaps to the extent it is available. We also consider the credit risk measurement implied by that data in determining our default probability percentages, and we evaluate its reliability based upon market liquidity, comparability, and other factors. We also use a credit-spread adjustment in order to reflect our own credit risk in determining the fair value of our derivative liabilities.

We regularly evaluate and validate the inputs we use to estimate fair value by a number of methods, consisting of various market price verification procedures, including the use of pricing services and multiple broker quotes to support the market price of the various commodities in which we transact, as well as review and verification of models and changes to those models. These activities are undertaken by individuals that are independent of those responsible for estimating fair value.

The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy or some combination thereof. Thus, even though we are required to classify these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

The following table sets forth a reconciliation of changes in Level 3 fair value measurements:

	Year Ended December 31, 2009	Year Ended December 31, 2008
	(In millions)	
Balance at beginning of period	**$ 37.0**	$(147.1)
Realized and unrealized (losses) gains:		
Recorded in income	**(486.9)**	471.2
Recorded in other comprehensive income	**201.6**	(511.9)
Purchases, sales, issuances, and settlements	**49.1**	37.6
Transfers into and out of Level 3	**(92.3)**	187.2
Balance at end of year	**$(291.5)**	$ 37.0
Change in unrealized gains recorded in income relating to derivatives still held at end of year	**$ (27.8)**	$ 800.1

Realized and unrealized gains (losses) are included primarily in "Nonregulated revenues" for our derivative contracts that are marked-to-market in our Consolidated Statements of Income (Loss) and are included in "Accumulated other comprehensive loss" for our derivative contracts designated as cash-flow hedges in our Consolidated Balance Sheets. We discuss the income statement classification for realized gains and losses related to cash-flow hedges for our various hedging relationships in *Note 1*.

Realized and unrealized gains (losses) include the realization of derivative contracts through maturity. This includes the fair value, as of the beginning of each quarterly reporting period, of contracts that matured during each quarterly reporting period. Purchases, sales, issuances, and settlements represent cash paid or received for option premiums, and the acquisition or termination of derivative contracts prior to maturity. Transfers into Level 3 represent existing assets or liabilities that were previously categorized at a higher level for which the inputs to the model became unobservable. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in either Level 1 or Level 2. Because the depth and liquidity of the power markets varies substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of our bilateral derivative contracts changes frequently. As a result, we also expect derivatives balances to transfer into and out of Level 3 frequently based on changes in the observable data available as of the end of the period.

Nonrecurring Measurements

As of December 31, 2009, there were no assets or liabilities measured at fair value on a nonrecurring basis. The table below set forth by level within the fair value hierarchy our financial assets and liabilities that were measured at fair value on a nonrecurring basis as of December 31, 2008:

	Fair Value at December 31, 2008	Level 1	Level 2	Level 3	Losses for the year ended December 31, 2008
	(In millions)				
Equity method investment	$17.7	$17.7	$—	$—	$124.4

As described more fully in *Note 2*, during the third and fourth quarters of 2008 we recorded other-than-temporary impairment charges of $54.7 million and $69.7 million, respectively, on our equity method investment in CEP. The fair value of CEP is a Level 1 measurement because CEP is a publicly traded stock on the New York Stock Exchange and the fair value is a quoted price in an active market.

Fair Value of Financial Instruments

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table:

At December 31,	**2009**		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets—Constellation Energy	**$ 167.6**	**$ 166.0**	$2,264.5	$2,264.5
Fixed-rate long-term debt:				
Constellation Energy (including BGE)	**4,225.0**	**4,433.1**	6,995.4	6,290.3
BGE	**2,200.1**	**2,280.5**	2,265.1	1,990.2
Variable-rate long-term debt:				
Constellation Energy (including BGE)	**649.9**	**649.9**	736.7	736.7
BGE	**—**	**—**	—	—

We use the following methods and assumptions for estimating fair value disclosures for financial instruments:

- cash and cash equivalents, net accounts receivable, other current assets, certain current liabilities, short-term borrowings, current portion of long-term debt, and certain deferred credits and other liabilities: because of their short-term nature, the amounts reported in our Consolidated Balance Sheets approximate fair value,
- investments and other assets: the fair value is based on quoted market prices where available, and
- long-term debt: the fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates.

14 Stock-Based Compensation

Under our long-term incentive plans, we grant stock options, performance and service-based restricted stock, performance- and service-based units, and equity to officers, key employees, and members of the Board of Directors. In May 2007, shareholders approved Constellation Energy's 2007 Long-Term Incentive Plan, under which we can grant up to a total of 9,000,000 shares. Any shares covered by an outstanding award under any of our long-term incentive plans that are forfeited or cancelled, expire or are settled in cash will become available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2009, there were 5,790,545 shares available for issuance under the 2007 Long-Term Incentive Plan. At December 31, 2009, we had stock options, restricted stock, performance units and equity grants outstanding as discussed below. We may issue new shares, reuse forfeited shares, or buy shares in the market in order to deliver shares to employees for our equity grants. BGE officers and key employees participate in our stock-based compensation plans. The expense recognized by BGE in 2009, 2008, and 2007 was not material to BGE's financial results.

Non-Qualified Stock Options

Options are granted with an exercise price equal to the market value of the common stock at the date of grant, become vested over a period up to three years (expense recognized in tranches), and expire ten years from the date of grant.

The fair value of our stock-based awards was estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted- average assumptions:

	2009	2008	2007
Risk-free interest rate	**1.95%**	2.57%	4.69%
Expected life (in years)	**4.0**	4.0	4.0
Expected market price volatility factor	**37.8%**	25.8%	20.3%
Expected dividend yield	**4.83%**	1.85%	2.5%

We use the historical data related to stock option exercises in order to estimate the expected life of our stock options. We also use historical data (measured on a daily basis) for a period equal to the duration of the expected life of option awards, information on the volatility of an identified group of peer companies, and implied volatilities for certain publicly traded options in Constellation Energy common stock in order to estimate the volatility factor. We believe that the use of this data to estimate these factors provides a reasonable basis for our assumptions. The risk-free interest rate for the periods within the expected life of the option is based on the U.S Treasury yield curve in effect and the expected dividend yield is based on our current estimate for dividend payout at the time of grant.

Summarized information for our stock option grants is as follows:

	2009		2008		2007	
	Shares	**Weighted-Average Exercise Price**	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
			(Shares in thousands)			
Outstanding, beginning of year	**6,058**	**$59.99**	6,145	$55.90	6,051	$47.23
Granted with exercise prices at fair market value	**3,511**	**20.14**	1,434	93.79	1,759	76.22
Exercised	**(83)**	**31.07**	(375)	47.02	(1,411)	41.91
Forfeited/expired	**(1,340)**	**52.41**	(1,146)	84.59	(254)	67.85
Outstanding, end of year	**8,146**	**$44.36**	6,058	$59.99	6,145	$55.90
Exercisable, end of year	**4,114**	**$55.81**	4,665	$52.13	4,043	$48.51
Weighted-average fair value per share of options granted with exercise prices at fair market value		**$ 4.24**		$18.75		$13.76

The following table summarizes additional information about stock options during 2009, 2008 and 2007:

	2009	2008	2007
	(In millions)		
Stock Option Expense Recognized	**$14.2**	$11.0	$15.1
Stock Options Exercised:			
Cash Received for Exercise Price	**2.6**	20.2	43.4
Intrinsic Value Realized by Employee	**0.2**	14.1	67.6
Realized Tax Benefit	**0.1**	5.7	26.7
Fair Value of Options that Vested	**11.0**	98.3	82.7

As of December 31, 2009, we had $4.0 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards, of which $2.9 million is expected to be recognized during 2010.

The following table summarizes additional information about stock options outstanding at December 31, 2009 (stock options in thousands):

	Outstanding		Exercisable		Weighted-Average Remaining Contractual Life
Range of Exercise Prices	Stock Options	Aggregate Intrinsic Value	Stock Options	Aggregate Intrinsic Value	
		(In millions)		(In millions)	(In years)
$ 0 – $ 20	3,140	$49.4	—	$ —	9.2
$20 – $ 40	1,141	3.1	996	2.1	4.3
$40 – $ 60	2,306	—	2,306	—	5.6
$60 – $ 80	792	—	543	—	7.2
$80 – $100	767	—	269	—	8.1
	8,146	$52.5	4,114	$2.1	

Restricted Stock Awards

In addition to stock options, we issue common stock based on meeting certain service goals. This stock vests to participants at various times ranging from one to five years if the service goals are met. We account for our service-based awards as equity awards, whereby we recognize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period either ratably or in tranches (depending if the award has cliff or graded vesting).

We recorded compensation expense related to our restricted stock awards of $16.7 million in 2009, $35.3 million in 2008, and $35.8 million in 2007. The tax benefits received associated with our restricted awards were $6.7 million in 2009, $20.1 million in 2008, and $17.6 million in 2007. Summarized share information for our restricted stock awards is as follows:

	2009	2008	2007
	(Shares in thousands)		
Outstanding, beginning of year	**1,033**	1,322	1,207
Granted	**866**	365	710
Released to participants	**(701)**	(536)	(552)
Canceled	**(181)**	(118)	(43)
Outstanding, end of year	**1,017**	1,033	1,322
Weighted-average fair value of restricted stock granted (per share)	**$19.83**	$94.62	$75.29
Total fair value of shares for which restriction has lapsed (in millions)	**$ 16.5**	$ 49.7	$ 44.5

As of December 31, 2009, we had $8.6 million of unrecognized compensation cost related to the unvested portion of outstanding restricted stock awards expected to be recognized within a 29-month period. At December 31, 2009, we have recorded in "Common shareholders' equity" approximately $37.4 million and approximately $47.8 million at December 31, 2008 for the unvested portion of service-based restricted stock granted from 2007 until 2009 to officers and other employees that is contingently redeemable in cash upon a change in control.

Performance-Based Units

We recognize compensation expense ratably for our performance-based awards, which are classified as liability awards, for which the fair value of the award is remeasured at each reporting period. Each unit is equivalent to $1 in value and cliff vests at the end of a three-year service and performance period. The level of payout is based on the achievement of certain performance goals at the end of the three-year period and will be settled in cash. We reported compensation expense of $1.5 million in 2009, a reduction of expense of $3.2 million in 2008, and compensation expense of $17.6 million in 2007 for these awards. During the 12 months ended December 31, 2009, no performance-based unit awards vested. During the 12 months ended December 31, 2008, our 2005 performance-based unit award vested and we paid $24.2 million in cash to settle the award. During the 12 months ended December 31, 2007, our 2004 performance-based unit award vested and we paid $19.7 million in cash to settle the award. As of December 31, 2009, we had $10.0 million of unrecognized compensation cost related to the unvested portion of outstanding performance-based unit awards expected to be recognized within a 26-month period.

Equity-Based Grants

We recorded compensation expense of $0.9 million in 2009, $0.9 million in 2008, and $0.9 million in 2007 related to equity-based grants to members of the Board of Directors.

15 Merger and Acquisitions

CLT Efficient Technologies Group

On July 1, 2009, we acquired CLT Efficient Technologies Group (CLT). We include CLT as part of our other nonregulated businesses and have included its results of operations in our consolidated financial statements since the date of acquisition. CLT is an energy services company that provides energy performance contracting and energy efficiency engineering services.

We acquired 100% ownership of CLT for $21.9 million, of which $20.8 million was paid in cash at closing.

Our final purchase price allocation related to CLT is as follows:

At July 1, 2009	*(In millions)*
Current assets	$ 5.7
Goodwill (1)	18.6
Other assets	2.3
Total assets acquired	26.6
Current liabilities	(4.7)
Net assets acquired	$21.9

(1) 100% deductible for tax purposes.

The pro-forma impact of the CLT acquisition would not have been material to our results of operations for the years ended December 31, 2009, 2008, and 2007.

Criterion Wind Project

On November 30, 2009, we signed an agreement to acquire the Criterion wind project in Garrett County, Maryland. The completed cost of this project is expected to be approximately $140 million. This 70 MW wind energy project would be developed, constructed, owned, and operated by us. We expect to close this transaction, subject to certain conditions in the first quarter of 2010 and expect commercial operation of the facility in the fall of 2010.

Termination of Merger Agreement with MidAmerican

On December 17, 2008 Constellation Energy and MidAmerican agreed to terminate the Agreement and Plan of Merger the parties entered into on September 19, 2008.

In connection with the termination and conversion of our Series A Preferred Stock, we made certain payments and issued certain securities to MidAmerican. Specifically, we:

- paid MidAmerican the $175 million merger termination fee,
- paid MidAmerican approximately $418 million in lieu of the number of shares of our common stock (valued at $26.50 per share) that were due to MidAmerican on the conversion of Series A Preferred Stock but that could not be issued due to regulatory limitations,
- issued and delivered a total of 19,897,322 shares of our common stock, representing 9.99% of our total outstanding common shares (after giving effect to the issuance, due upon conversion of the Series A Preferred Stock). The fair value of the common stock on the date of issuance was estimated to be $572.6 million based on the stock price at the time of issuance. We also delivered to MidAmerican 14% Senior Notes in the aggregate principal amount of $1.0 billion, also issued upon the conversion of the Series A Preferred Stock.

We discuss the merger termination fee in more detail in *Note 2*.

Nufcor International Limited

On June 26, 2008, we acquired 100% ownership of Nufcor International Limited (Nufcor), a uranium market participant that provides marketing services to uranium producers, utilities and an investment fund in the North American and European markets, for $102.8 million. We included Nufcor as part of our Global Commodities operations in our merchant energy business segment and had included its results of operations in our consolidated financial statements since the date of acquisition until its sale on June 30, 2009. We discuss this divestiture in more detail in *Note 2*.

West Valley Power Plant

On June 1, 2008, we acquired the West Valley Power Plant, a 200 MW gas-fired peaking plant located in Utah for approximately $88.6 million (including direct costs). We accounted for this transaction as an asset acquisition and have included this plant's results of operations in the Generation operations of our merchant energy business segment since the date of acquisition. We allocated the purchase price primarily to the equipment with lesser amounts allocated to land and spare parts inventory.

Hillabee Energy Center

On February 14, 2008, we acquired the Hillabee Energy Center, a partially completed 740 MW gas-fired combined cycle power generation facility located in Alabama for $156.9 million (including direct costs), which we accounted for as an asset acquisition. We allocated the purchase price primarily to the equipment with lesser amounts allocated to land and contracts acquired. We plan to complete the construction of this facility and expect it to be ready for commercial operation in the first quarter of 2010.

16 Related Party Transactions

Constellation Energy

CENG

On November 6, 2009, upon the sale of a membership interest in CENG, our nuclear generation and operation business, to EDF, we deconsolidated CENG and began accounting for our 50.01% membership interest in CENG as an equity method investment.

In connection with the closing of the transaction with EDF, we entered into a power purchase agreement (PPA) with CENG with a fair value of $0.8 billion where we will purchase between 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs over the five year term of the PPA.

For the period from November 6, 2009 through December 31, 2009, we recognized $122.5 million in purchased power costs from CENG.

In addition to the PPA, we entered into a power services agency agreement (PSA) and an administrative service agreement (ASA). The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and recognize average annual revenue of approximately $16 million. For the period from November 6, 2009 through December 31, 2009, we recognized $2.7 million in revenue for services rendered under the PSA with CENG.

The ASA is a one year agreement that is renewable annually under which we will provide administrative support services to CENG for a fee of approximately $66 million for 2010. The fees for administrative support services will be subject to change in future years based on the level of services provided. The charges under this agreement are intended to represent the actual cost of the services provided to CENG from us. For the period from November 6, 2009 through December 31, 2009, we recognized $10.0 million for services rendered under the ASA with CENG as an offset to operating expenses.

UNE

We discuss our relationship with UNE in *Note 4*.

CEP

On March 31, 2008, our merchant energy business sold its working interest in 83 oil and natural gas producing wells in Oklahoma to CEP, an equity method investment of Constellation Energy, for total proceeds of approximately $53 million. Our merchant energy business recognized a $14.3 million gain, net of the minority interest gain of $0.7 million on the sale and exclusive of our 28.5% ownership interest in CEP. This gain is recorded in "Gains on Sales of Assets" in our Consolidated Statements of Income (Loss).

BGE—Income Statement

BGE is obligated to provide market-based standard offer service to all of its electric customers for varying periods. Bidding to supply BGE's market-based standard offer service to electric customers will occur from time to time through a competitive bidding process approved by the Maryland PSC.

Our merchant energy business will supply a portion of BGE's market-based standard offer service obligation to electric customers through May 31, 2012.

The cost of BGE's purchased energy from nonregulated subsidiaries of Constellation Energy to meet its standard offer service obligation was as follows:

Year Ended December 31,	**2009**	2008	2007
		(In millions)	
Electricity purchased for resale expenses	**$623.5**	$802.0	$1,139.6

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. We believe this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. Under the Maryland PSC's October 30, 2009 order approving the transaction with EDF, we are limited to allocating no more than 31% of these costs to BGE. Other nonregulated affiliates of BGE also charge BGE for the costs of certain services provided.

The following table presents the costs Constellation Energy charged to BGE in each period.

Year ended December 31,	**2009**	2008	2007
		(In millions)	
Charges to BGE	**$164.7**	$153.6	$160.8

BGE—Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $314.7 million at December 31, 2009 and $148.8 million at December 31, 2008.

As part of the ring-fencing measures required by the Maryland PSC in its order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010.

BGE's Consolidated Balance Sheets include intercompany amounts related to BGE's purchases to meet its standard offer service obligation, BGE's gas purchases, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, Constellation Energy and its nonregulated affiliates' charges to BGE, and the participation of BGE's employees in the Constellation Energy defined benefit plans.

17 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair statement. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2009 Quarterly Data—Constellation Energy

	Revenues	Income (Loss) from Operations	Other (Expense) Income *	Total Fixed Charges *	Net Income (Loss)	Net Income Attributable to Common Stock	Earnings (Loss) Per Share from Operations—Diluted	Earnings (Loss) Per Share of Common Stock—Diluted
	(In millions, except per share amounts)							
Quarter Ended								
March 31	**$ 4,303.4**	**$ (212.1)**	**$ (56.3)**	**$ 93.5**	**$ (119.7)**	**$ (123.5)**	**$ (0.62)**	**$ (0.62)**
June 30	**3,864.1**	**230.6**	**(15.0)**	**84.5**	**28.3**	**8.1**	**0.04**	**0.04**
September 30	**4,027.7**	**534.3**	**11.6**	**80.1**	**167.4**	**137.6**	**0.69**	**0.69**
December 31	**3,403.6**	**7,428.2**	**(81.0)**	**92.0**	**4,427.4**	**4,421.2**	**21.96**	**21.96**
Year Ended								
December 31	**$15,598.8**	**$7,981.0**	**$(140.7)**	**$350.1**	**$4,503.4**	**$4,443.4**	**$22.19**	**$22.19**

2009 Quarterly Data—BGE

	Revenues	Income (Loss) from Operations	Net Income	Net Income Attributable to Common Stock
	(In millions)			
Quarter Ended				
March 31	**$1,193.7**	**$ 168.7**	**$ 85.0**	**$ 81.7**
June 30	**767.4**	**54.3**	**16.0**	**12.7**
September 30	**866.5**	**78.7**	**32.3**	**28.6**
December 31	**751.4**	**(33.3)**	**(42.6)**	**(38.2)**
Year Ended				
December 31	**$3,579.0**	**$ 268.4**	**$ 90.7**	**$ 84.8**

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution.

* *In the fourth quarter of 2009, we modified our policy for the classification of credit facility fees and we reclassified amounts for the first three quarters of 2009 to conform with that policy. Amounts prior to 2009 were not material. See Note 1 for a discussion of our policy for the classification of credit facility fees.*

First quarter results include:

- a $184.2 million after-tax loss on the sale of a majority of our international commodities operation, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss, and earnings that are no longer part of our core business,
- a $5.1 million after-tax charge for the impairment of our investment in CEP LLC,
- a $23.8 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $6.0 million after-tax charge for certain long-lived assets that ceased to be used in connection with the divestiture of a majority of our international commodities operation and our Houston-based gas trading operation,
- merger termination and strategic alternatives costs totaling $42.3 million after-tax,
- workforce reduction costs totaling $4.2 million after-tax, and
- a $3.7 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Second quarter results include:

- a $123.8 million after-tax loss on the sale of a majority of our international commodities operation, our Houston-based gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss, and earnings that are no longer part of our core business,
- a $59.0 after-tax charge for the impairment of our shipping joint venture,
- a $6.1 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $4.9 million after-tax charge for certain long-lived assets that ceased to be used in connections with the divestiture of a majority of our international commodities operation and our Houston-based gas trading operation as well as the write-off of an uncollectible advance to an affiliate,
- a $1.5 million after-tax charge for the impairment of our investment in CEP LLC,
- merger termination and strategic alternatives costs totaling $4.0 million after-tax,
- workforce reduction costs totaling $1.1 million after-tax, and
- a $5.2 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Third quarter results include:

- a $62.9 million after-tax loss on the sale of a majority of our international commodities operation, our Houston-based gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss, and earnings that are no longer part of our core business,

- a $19.7 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments (primarily due to income tax adjustments),
- a $9.0 million after-tax charge for certain long-lived assets that ceased to be used in connection with the divestiture of a majority of our international commodities operation and our Houston-based gas trading operation,
- merger termination and strategic alternatives costs totaling $4.9 million after-tax,
- workforce reduction costs totaling $1.6 million after-tax, and
- a $8.2 million after-tax amortization of credit facility amendment fees in connection with the EDF transaction.

Fourth quarter results include:

- a $4,456.1 million after-tax gain on sale of a 49.99% membership interest in CENG to EDF,
- a $17.8 million after-tax charge for amortization of the basis difference in CENG,
- a $1.0 million after-tax loss on the sale of a majority of our international commodities operation, our Houston-based gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss, and earnings that are no longer part of our core business,
- a $3.6 million after-tax charge for certain long-lived assets that ceased to be used in connections with the divestiture of a majority of our international commodities operation and our Houston-based gas trading operation,
- a $7.1 million after-tax charge for the impairment of BGE's nonregulated subsidiary, District Chilled Water, net of noncontrolling interest,
- a $2.8 million after-tax benefit for the impairment of certain of our nuclear decommissioning trust fund investments (primarily due to income tax adjustments),
- a $10.0 million after-tax loss on redemption of our zero coupon senior notes,
- a $67.1 million after-tax charge for a BGE customer rate credit,
- merger termination and strategic alternatives costs benefit totaling $37.4 million after-tax due to a true-up for 2008 and 2009 expenses that became tax deductible upon the close of the transaction with EDF on November 6, 2009,
- workforce reduction costs totaling $2.4 million after-tax, and
- a $20.6 million after-tax credit facility amendment and termination fees in connection with the EDF transaction.

We discuss these items in *Note 2*.

2008 Quarterly Data—Constellation Energy

	Revenues	Income (Loss) from Operations	Net Income (Loss)	Net Income (Loss) Attributable to Common Stock	Earnings (Loss) Per Share from Operations—Diluted	Earnings (Loss) Per Share of Common Stock—Diluted
	(In millions, except per share amounts)					
Quarter Ended						
March 31	**$ 4,812.2**	**$ 254.3**	**$ 149.4**	**$ 145.7**	**$ 0.81**	**$ 0.81**
June 30	**4,756.1**	**331.7**	**175.0**	**171.5**	**0.95**	**0.95**
September 30	**5,323.6**	**(228.4)**	**(222.1)**	**(225.7)**	**(1.27)**	**(1.27)**
December 31	**4,850.0**	**(1,335.7)**	**(1,420.7)**	**(1,405.9)**	**(7.75)**	**(7.75)**
Year Ended						
December 31	**$19,741.9**	**$ (978.1)**	**$(1,318.4)**	**$(1,314.4)**	**$(7.34)**	**$(7.34)**

2008 Quarterly Data—BGE

	Revenues	Income (Loss) from Operations	Net Income	Net Income (Loss) Applicable to Common Stock
	(In millions)			
Quarter Ended				
March 31	**$1,105.8**	**$ 137.7**	**$ 76.2**	**$ 73.0**
June 30	**636.8**	**(131.1)**	**(104.2)**	**(107.4)**
September 30	**977.9**	**69.6**	**23.5**	**19.9**
December 31	**983.2**	**106.3**	**56.0**	**52.8**
Year Ended				
December 31	**$3,703.7**	**$ 182.5**	**$ 51.5**	**$ 38.3**

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and dilution as a result of issuing common shares during the year.

First quarter results include:

- a $3.9 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $6.6 million tax benefit related to the anticipated finalization of the Maryland settlement agreement, and
- a $9.1 million after-tax gain on the sale of certain working interests in an upstream gas property.

Second quarter results include:

- a $2.4 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a $13.4 million after-tax charge related to the write-down of our emission allowance inventory,
- a $125.3 million after-tax charge related to the one-time $170 residential electric customer credit related to the Maryland settlement agreement,
- a $2.1 million tax benefit related to the Maryland settlement agreement, and
- a $46.2 million after-tax gain on the sale of certain working interests in upstream gas properties.

Third quarter results include:

- a \$169.1 million after-tax charge for the impairment of goodwill,
- a \$86.6 million after-tax charge for the impairments of certain of our upstream gas properties,
- a \$34.2 million after-tax charge for the impairment of our investment in CEP LLC,
- a \$22.8 million after-tax charge related to the write-down of our emission allowance inventory,
- a \$15.3 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a \$18.9 million after-tax gain on the sale of a dry bulk vessel in our shipping joint venture,
- merger and strategic alternatives costs totaling \$37.3 million after-tax, of which BGE recorded \$10.6 million after-tax,
- estimated settlement costs totaling \$8.9 million after-tax related to a class action complaint alleging ash placement at a third party site damaged surrounding properties,
- workforce reduction costs totaling \$1.6 million after-tax related to our Customer Supply operations, and
- a \$2.0 million tax benefit related to the Maryland settlement agreement.

Fourth quarter results include:

- a \$119.8 million after-tax charge for the impairments of certain of our upstream gas properties,
- a \$50.6 million loss after-tax for an impairment of our investment in CEP LLC and a marketable security held by our Global Commodities operations,
- a \$7.5 million after-tax gain related to the recovery in the value of our emission allowance inventory,
- a \$60.4 million after-tax charge for the impairment of certain of our nuclear decommissioning trust fund investments,
- a \$39.3 million after-tax loss on the sale of certain upstream gas properties,
- merger termination and strategic alternatives costs totaling \$1,167.1 million after-tax, of which BGE recorded a cost reduction of \$10.6 million after-tax associated with the re-allocation of costs prior to EDF transaction to our merchant energy segment,
- workforce reduction costs totaling \$11.8 million after-tax related to our company-wide reduction in force,
- a \$0.6 after-tax benefit for an adjustment to the estimated settlement costs relating to the class action ash placement complaint,
- a \$2.1 million after-tax charge for an adjustment to the impairment of goodwill,
- a \$1.2 million loss after-tax related to a final true-up of the one-time \$170 residential electric customer credit related to the Maryland settlement agreement, and
- a \$5.3 million tax benefit related to the Maryland settlement agreement.

We discuss these items in *Note 2*.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Items 9A and 9A(T). Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The principal executive officer and principal financial officer of Constellation Energy have each evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of December 31, 2009 (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that Constellation Energy files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

The principal executive officer and principal financial officer of BGE have each evaluated the effectiveness of BGE's disclosure controls and procedures as of the Evaluation Date. Based on such evaluation, such officers have concluded that, as of the Evaluation Date, BGE's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that BGE files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

Each of Constellation Energy and BGE maintains a system of internal control over financial reporting as defined in Exchange Act Rule 13a-15(f). The Management's Reports on Internal Control Over Financial Reporting of each of Constellation Energy and BGE are included in *Item 8. Financial Statements and Supplementary Data* included in this report. As BGE is not an accelerated filer as defined in Exchange Act Rule 12b-2, its Management's Report on Internal Control over Financial Reporting is not deemed to be filed for purposes of Section 18 of the Exchange Act as permitted by the rules and regulations of the Securities and Exchange Commission.

Changes in Internal Control

During the quarter ended December 31, 2009, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

BGE meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section related to BGE are not presented.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item with respect to directors and corporate governance will be set forth under *Proposal No. 1: Election of Directors* in the Proxy Statement and incorporated herein by reference.

The information required by this item with respect to executive officers of Constellation Energy, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, is set forth following *Item 4 of Part I* of this Form 10-K under *Executive Officers of the Registrant*.

Item 11. Executive Compensation

The information required by this item will be set forth under *Executive and Director Compensation* and *Report of Compensation Committee* in the Proxy Statement and incorporated herein by reference.

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

The additional information required by this item will be set forth under *Stock Ownership* in the Proxy Statement and incorporated herein by reference.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information as of December 31, 2009:

Plan Category	(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 item (a))
	(In thousands)		*(In thousands)*
Equity compensation plans approved by security holders	7,432	$44.52	5,791
Equity compensation plans not approved by security holders	714	$42.63	—
Total	8,146	$44.36	5,791

The plans that do not require shareholder approval are the Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan (Designated as Exhibit No. 10(k)) and the Constellation Energy Group, Inc. Management Long-Term Incentive Plan (Designated as Exhibit No. 10(l)). A brief description of the material features of each of these plans is set forth below.

2002 Senior Management Long-Term Incentive Plan

The 2002 Senior Management Long-Term Incentive Plan became effective May 24, 2002 and authorized the issuance of up to 4,000,000 shares of Constellation Energy common stock in connection with the grant of equity awards. No further awards will be made under this plan. Any shares covered by an outstanding award that is forfeited or cancelled, expires or is settled in cash will become available for issuance under the shareholder-approved 2007 Long-Term Incentive Plan. Shares delivered pursuant to awards under this plan may be authorized and unissued shares or shares purchased on the open market in accordance with the applicable securities laws. Restricted stock, restricted stock unit, and performance unit award payouts will be accelerated and stock options and stock appreciation rights gains will be paid in cash in the event of a change in control, as defined in the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

Management Long-Term Incentive Plan

The Management Long-Term Incentive Plan became effective February 1, 1998 and authorized the issuance of up to 3,000,000 shares of Constellation Energy common stock in connection with the grant of equity awards. No further awards will be made under this plan. Any shares covered by an outstanding award that is forfeited or cancelled, expires or is settled in cash will become available for issuance under the shareholder-approved 2007 Long-Term Incentive Plan. Shares delivered pursuant to awards under the plan may be authorized and unissued shares or shares purchased on the open market in accordance with applicable securities laws. Restricted stock, restricted stock units, and performance unit award payouts will be accelerated and stock options and stock appreciation rights will become fully exercisable in the event of a change in control, as defined by the plan. The plan is administered by Constellation Energy's Chief Executive Officer.

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

The additional information required by this item will be set forth under *Related Persons Transactions* and *Determination of Independence* in the Proxy Statement and incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item will be set forth under *Ratification of PricewaterhouseCoopers LLP as Independent Registered Public Accounting Firm for 2010* in the Proxy Statement and incorporated herein by reference.

PART IV
Item 15. Exhibits and Financial Statement Schedules

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

1. Financial Statements:
   Reports of Independent Registered Public Accounting Firm dated February 26, 2010 of PricewaterhouseCoopers LLP
   Consolidated Statements of Income (Loss)—Constellation Energy Group for three years ended December 31, 2009
   Consolidated Balance Sheets—Constellation Energy Group at December 31, 2009 and December 31, 2008
   Consolidated Statements of Cash Flows—Constellation Energy Group for three years ended December 31, 2009
   Consolidated Statements of Common Shareholders' Equity and Comprehensive Income (Loss)—Constellation Energy Group for three years ended December 31, 2009
   Consolidated Statements of Income—Baltimore Gas and Electric Company for three years ended December 31, 2009
   Consolidated Balance Sheets—Baltimore Gas and Electric Company at December 31, 2009 and December 31, 2008
   Consolidated Statements of Cash Flows—Baltimore Gas and Electric Company for three years ended December 31, 2009
   Notes to Consolidated Financial Statements
2. Financial Statement Schedules:
   Schedule II—Valuation and Qualifying Accounts
   Schedules other than Schedule II are omitted as not applicable or not required.
3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number		
*2	—	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	—	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	—	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	—	Termination Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., Constellation Generation II, LLC, Constellation Power Source Generation, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc., MEHC Investment, Inc. and Electricite de France International S.A. (Designated as Exhibit 2.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(d)	—	Master Put Option and Membership Interest Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 21 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(e)	—	Amendment No. 1 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated September 16, 2009, File No. 1-12869.)
*2(f)	—	Amendment No. 2 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated September 22, 2009, File No. 1-12869.)
*2(g)	—	Amendment No. 3 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated October 30, 2009, File No. 1-12869.)

*2(h)	—	Amendment No. 4 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)
*3(a)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of December 17, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(b)	—	Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*3(c)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of September 19, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
*3(d)	—	Articles of Amendment to the Charter of Constellation Energy Group, Inc. as of July 21, 2008. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q dated June 30, 2008, File Nos. 1-12869 and 1-1910.)
*3(e)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of April 10, 2007. (Designated as Exhibit 3(a) to the Current Report on Form 8-K dated April 10, 2007, File No. 1-12869.)
*3(f)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)
*3(g)	—	Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)
*3(h)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated July 19, 1999, File Nos. 1-12869 and 1-1910.)
*3(i)	—	Articles of Amendment and Restatement of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Appendix B to Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed March 3, 1999, File No. 33-64799.)
*3(j)	—	Bylaws of Constellation Energy Group, Inc., as amended to July 18, 2008. (Designated as Exhibit No. 3 to the Current Report on Form 8-K dated July 18, 2008, File No. 1-12869.)
*3(k)	—	Articles of Amendment to the Charter of BGE as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)
*3(l)	—	Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)
*3(m)	—	Bylaws of BGE, as amended to February 4, 2010. (Designated as Exhibit No. 3.2 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)
*4(a)	—	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)
*4(b)	—	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)
*4(c)	—	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(d)	—	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)

*4(e)	—	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
*4(f)	—	Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)
*4(g)	—	Form of Subordinated Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(h)	—	Form of Supplemental Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(i)	—	Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(j)	—	Form of Junior Subordinated Debenture (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(k)	—	Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)
*4(l)	—	Indenture dated as of July 24, 2006 between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)
*4(m)	—	First Supplemental Indenture between BGE and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
*4(n)	—	Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee (including form of BGE Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(o)	—	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File Nos. 1-12869 and 1-1910.)
*4(p)	—	BGE Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)
*4(q)	—	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*4(r)	—	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File No. 1-1910.)
*4(s)	—	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)
+*10(a)	—	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, File Nos. 1-12869 and 1-1910.)

+*10(b)	—	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*10(c)	—	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(d)	—	Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated. (Designated as Exhibit No. 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(e)	—	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(e) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(f)	—	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(f) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
+*10(g)	—	Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)
+*10(h)	—	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File Nos. 1-12869 and 1-1910.)
+*10(i)	—	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(j)	—	Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated. (Designated as Exhibit 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2006, File Nos. 1-12869 and 1-1910.)
+*10(k)	—	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(l)	—	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)
+*10(m)	—	Constellation Energy Group, Inc. 2007 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)
*10(n)	—	Grantor Trust Agreement Dated as of February 27, 2004 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
*10(o)	—	Grantor Trust Agreement dated as of February 27, 2004 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)
+*10(p)	—	Consent of Mayo A. Shattuck III to termination of change-in-control agreement. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(q)	—	Consent of Michael J. Wallace to termination of change-in-control agreement. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(r)	—	Consent of Henry B. Barron, Jr. to termination of change-in-control agreement. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)
+*10(s)	—	Offer letter between Constellation Energy Group, Inc. and Henry B. Barron, Jr. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

+*10(t)	—	Letter agreement between Constellation Energy Group, Inc. and Jonathan W. Thayer. (Designated as Exhibit No. 10(e) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)
+*10(u)	—	Offer letter between Constellation Energy Group, Inc. and Brenda Boultwood. (Designated as Exhibit No. 10(f) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)
*10(v)	—	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(w)	—	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)
*10(x)	—	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)
*10(y)	—	Payment Guaranty, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France, S.A. (Designated as Exhibit No. 10.4 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(z)	—	Amended and Restated Investor Agreement, dated December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France International, SA (Designated as Exhibit 10.7 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(aa)	—	Letter Agreement dated April 21, 2009 among Constellation Energy Group, Inc., EDF Development Inc. and E.D.F. International S.A. (Designated as Exhibit No. 10(i) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)
*10(bb)	—	Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10.6 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*10(cc)	—	Amendment No. 1, dated as of April 15, 2009, to the Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10(h) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)
12(a)	—	Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.
12(b)	—	Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
21	—	Subsidiaries of the Registrant.
23	—	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31(a)	—	Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(c)	—	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(d)	—	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32(a)	—	Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32(b)	—	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32(c)	—	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32(d)	—	Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99(a)	—	Audited Financial Statements of Constellation Energy Nuclear Group, LLC.
*99(b)	—	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(c)	—	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., BGE and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(d)	—	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Taxonomy Extension Schema Document
101.PRE	—	XBRL Taxonomy Presentation Linkbase Document
101.LAB	—	XBRL Taxonomy Label Linkbase Document
101.CAL	—	XBRL Taxonomy Calculation Linkbase Document
101.DEF	—	XBRL Taxonomy Definition Linkbase Document

+ Management contract or compensatory plan or arrangement.

* Incorporated by Reference.

In accordance with Rule 402 of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES
AND
BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to Other Accounts—Describe	(Deductions)—Describe	Balance at end of period
			(In millions)		
Reserves deducted in the Balance Sheet from the assets to which they apply:					
Constellation Energy					
Accumulated Provision for Uncollectibles					
2009	$ 240.6	$ 71.2	$ (5.0)(A)	$ (146.2)(C)	$ 160.6
2008	44.9	127.1	102.3 (B)	(33.7)(C)	240.6
2007	48.9	31.3	—	(35.3)(C)	44.9
Valuation Allowance					
Net unrealized (gain) loss on available for sale securities					
2009	2.1	(3.6)	(1.3)(D)	—	(2.8)
2008	(17.3)	7.0	0.3 (D)	12.1 (E)	2.1
2007	(18.5)	—	1.2 (D)	—	(17.3)
Net unrealized (gain) loss on nuclear decommissioning trust funds					
2009	(49.6)	—	(201.0)(D)	250.6 (F)	—
2008	(256.7)	—	207.1 (D)	—	(49.6)
2007	(206.1)	—	(50.6)(D)	—	(256.7)
BGE					
Accumulated Provision for Uncollectibles					
2009	34.2	41.8	—	(28.8)(C)	47.2
2008	21.1	34.5	—	(21.4)(C)	34.2
2007	16.1	21.0	—	(16.0)(C)	21.1

(A) Represents amounts recorded as an increase to nonregulated revenues resulting from a settlement with a counterparty that was in default.

(B) Represents amounts recorded as a reduction to nonregulated revenues resulting from liquidated damages claims upon termination of derivatives which were determined to be uncollectible.

(C) Represents principally net amounts charged off as uncollectible.

(D) Represents amounts recorded in or reclassified from accumulated other comprehensive income.

(E) Represents sale of a marketable security.

(F) Represents decrease due to the deconsolidation of CENG.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Group, Inc., the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY GROUP, INC.
(REGISTRANT)

Date: February 26, 2010

By /s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Group, Inc., the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ M. A. Shattuck III **M. A. Shattuck III**	Chairman of the Board, President, Chief Executive Officer, and Director	February 26, 2010
Principal financial officer:		
By /s/ J. W. Thayer **J. W. Thayer**	Senior Vice President and Chief Financial Officer	February 26, 2010
Principal accounting officer:		
By /s/ B. P. Wright **B. P. Wright**	Vice President, Chief Accounting Officer, and Controller	February 26, 2010
Directors:		
/s/ Y. C. de Balmann **Y. C. de Balmann**	Director	February 26, 2010
/s/ A. C Berzin **A. C. Berzin**	Director	February 26, 2010
/s/ J. T. Brady **J. T. Brady**	Director	February 26, 2010
/s/ J. R. Curtiss **J. R. Curtiss**	Director	February 26, 2010
/s/ F. A. Hrabowski, III **F. A. Hrabowski, III**	Director	February 26, 2010

Signature	Title	Date
/s/ N. Lampton **N. Lampton**	Director	February 26, 2010
/s/ R. J. Lawless **R. J. Lawless**	Director	February 26, 2010
/s/ J. L. Skolds **J. L. Skolds**	Director	February 26, 2010
/s/ M. D. Sullivan **M. D. Sullivan**	Director	February 26, 2010

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Baltimore Gas and Electric Company, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY
(REGISTRANT)

February 26, 2010

By /s/ KENNETH W. DEFONTES, JR.

Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Baltimore Gas and Electric Company, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and director:		
By /s/ K. W. DeFontes, Jr. **K. W. DeFontes, Jr.**	President, Chief Executive Officer, and Director	February 26, 2010
Principal financial and accounting officer:		
By /s/ K. W. Hadlock **K. W. Hadlock**	Senior Vice President and Chief Financial Officer	February 26, 2010
Directors:		
/s/ M. D. Sullivan **M. D. Sullivan**	Chairman of the Board of Directors	February 26, 2010
/s/ T. F. Brady **T. F. Brady**	Director	February 26, 2010
/s/ J. Haskins Jr. **J. Haskins Jr.**	Director	February 26, 2010
/s/ C. Hayden **C. Hayden**	Director	February 26, 2010
/s/ M. A. Shattuck III **M. A. Shattuck III**	Director	February 26, 2010

EXHIBIT INDEX

Exhibit Number		
*2	—	Agreement and Plan of Share Exchange between Baltimore Gas and Electric Company and Constellation Energy Group, Inc. dated as of February 19, 1999. (Designated as Exhibit No. 2 to the Registration Statement on Form S-4 dated March 3, 1999, File No. 33-64799.)
*2(a)	—	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(b)	—	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, File Nos. 1-12869 and 1-1910.)
*2(c)	—	Termination Agreement, dated December 17, 2008, by and among Constellation Energy Group, Inc., Constellation Generation II, LLC, Constellation Power Source Generation, Inc., MidAmerican Energy Holdings Company, MEHC Merger Sub Inc., MEHC Investment, Inc. and Electricite de France International S.A. (Designated as Exhibit 2.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(d)	—	Master Put Option and Membership Interest Purchase Agreement, dated as of December 17, 2008, by and among Constellation Energy Group, Inc., EDF Development, Inc. and Electricite de France International, S.A. (Designated as Exhibit No. 21 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*2(e)	—	Amendment No. 1 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated September 16, 2009, File No. 1-12869.)
*2(f)	—	Amendment No. 2 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated September 22, 2009, File No. 1-12869.)
*2(g)	—	Amendment No. 3 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated October 30, 2009, File No. 1-12869.)
*2(h)	—	Amendment No. 4 to the Master Put Option and Membership Interest Purchase Agreement. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)
*3(a)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of December 17, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)
*3(b)	—	Correction to Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 25, 2008. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)
*3(c)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of September 19, 2008. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated September 19, 2008, File No. 1-12869.)
*3(d)	—	Articles of Amendment to the Charter of Constellation Energy Group, Inc. as of July 21, 2008. (Designated as Exhibit No. 3(a) to the Quarterly Report on Form 10-Q dated June 30, 2008, File Nos. 1-12869 and 1-1910.)
*3(e)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of April 10, 2007. (Designated as Exhibit 3(a) to the Current Report on Form 8-K dated April 10, 2007, File No. 1-12869.)
*3(f)	—	Articles Supplementary to the Charter of Constellation Energy Group, Inc. as of November 20, 2001. (Designated as Exhibit No. 3(e) to the Annual Report on Form 10-K for the year ended December 31, 2001, File Nos. 1-12869 and 1-1910.)

*3(g) — Certificate of Correction to the Charter of Constellation Energy Group, Inc. as of September 13, 1999. (Designated as Exhibit No. 3(c) to the Annual Report on Form 10-K for the year ended December 31, 1999, File Nos. 1-12869 and 1-1910.)

*3(h) — Articles Supplementary to the Charter of Constellation Energy Group, Inc., as of July 19, 1999. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated July 19, 1999, File Nos. 1-12869 and 1-1910.)

*3(i) — Articles of Amendment and Restatement of Constellation Energy Group, Inc. as of April 30, 1999. (Designated as Appendix B to Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed March 3, 1999, File No. 33-64799.)

*3(j) — Bylaws of Constellation Energy Group, Inc., as amended to July 18, 2008. (Designated as Exhibit No. 3 to the Current Report on Form 8-K dated July 18, 2008, File No. 1-12869.)

*3(k) — Articles of Amendment to the Charter of BGE as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)

*3(l) — Charter of BGE, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, File No. 1-1910.)

*3(m) — Bylaws of BGE, as amended to February 4, 2010. (Designated as Exhibit No. 3.2 to the Current Report on Form 8-K dated February 4, 2010, File No. 1-1910.)

*4(a) — Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, File No. 333-75217.)

*4(b) — First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, File No. 333-102723.)

*4(c) — Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)

*4(d) — First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)

*4(e) — Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)

*4(f) — Indenture dated July 1, 1985, between BGE and The Bank of New York (Successor to Mercantile-Safe Deposit and trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, File No. 1-1910.)

*4(g) — Form of Subordinated Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(d) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(h) — Form of Supplemental Indenture between BGE and The Bank of New York, as Trustee in connection with the issuance of the Junior Subordinated Debentures. (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(i) — Form of Preferred Securities Guarantee (Designated as Exhibit 4(f) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(j) — Form of Junior Subordinated Debenture (Designated as Exhibit 4(e) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(k) — Form of Amended and Restated Declaration of Trust (including Form of Preferred Security) (Designated as Exhibit 4(c) to the Registration Statement on Form S-3 dated August 5, 2003, File No. 333-107681.)

*4(l) — Indenture dated as of July 24, 2006 between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, File No. 333-135991.)

*4(m) — First Supplemental Indenture between BGE and Deutsche Bank Trust Company Americas, as trustee, dated as of October 13, 2006. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

*4(n) — Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee (including form of BGE Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)

*4(o) — Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between BGE and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File Nos. 1-12869 and 1-1910.)

*4(p) — BGE Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, File Nos. 333-157637 and 333-157637-01.)

*4(q) — Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)

*4(r) — Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, File No. 1-1910.)

*4(s) — Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, File No. 1-12869.)

+*10(a) — Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, File Nos. 1-12869 and 1-1910.)

+*10(b) — Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

*10(c) — Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. (Designated as Exhibit No. 10(c) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

+*10(d) — Constellation Energy Group, Inc. Benefits Restoration Plan, as amended and restated. (Designated as Exhibit No. 10(d) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

+*10(e) — Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. (Designated as Exhibit No. 10(e) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

+*10(f) — Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. (Designated as Exhibit No. 10(f) to the Annual Report on Form 10-K for the year ended December 31, 2008, File Nos. 1-12869 and 1-1910.)

+*10(g) — Constellation Energy Group, Inc. Supplemental Benefits Plan, as amended and restated. (Designated as Exhibit No. 10(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, File Nos. 1-12869 and 1-1910.)

+*10(h) — Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File Nos. 1-12869 and 1-1910.)

+*10(i) — Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

+*10(j) — Constellation Energy Group, Inc. 2002 Executive Annual Incentive Plan, as amended and restated. (Designated as Exhibit 10(o) to the Annual Report on Form 10-K for the year ended December 31, 2006, File Nos. 1-12869 and 1-1910.)

+*10(k) — Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

+*10(l) — Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File Nos. 1-12869 and 1-1910.)

+*10(m) — Constellation Energy Group, Inc. 2007 Long-Term Incentive Plan, as amended and restated. (Designated as Exhibit 10(a) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

*10(n) — Grantor Trust Agreement Dated as of February 27, 2004 between Constellation Energy Group, Inc. and Citibank, N.A. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)

*10(o) — Grantor Trust Agreement dated as of February 27, 2004 between Constellation Energy Group, Inc. and T. Rowe Price Trust Company. (Designated as Exhibit No. 10(b) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File Nos. 1-12869 and 1-1910.)

+*10(p) — Consent of Mayo A. Shattuck III to termination of change-in-control agreement. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)

+*10(q) — Consent of Michael J. Wallace to termination of change-in-control agreement. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)

+*10(r) — Consent of Henry B. Barron, Jr. to termination of change-in-control agreement. (Designated as Exhibit No. 10.3 to the Current Report on Form 8-K dated December 10, 2009, File No. 1-12869.)

+*10(s) — Offer letter between Constellation Energy Group, Inc. and Henry B. Barron, Jr. (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

+*10(t) — Letter agreement between Constellation Energy Group, Inc. and Jonathan W. Thayer. (Designated as Exhibit No. 10(e) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

+*10(u) — Offer letter between Constellation Energy Group, Inc. and Brenda Boultwood. (Designated as Exhibit No. 10(f) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

*10(v) — Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)

*10(w) — Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, File No. 1-1910.)

*10(x) — Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, File No. 1-12869.)

*10(y) — Payment Guaranty, dated as of December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France, S.A. (Designated as Exhibit No. 10.4 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)

*10(z) — Amended and Restated Investor Agreement, dated December 17, 2008, by and between Constellation Energy Group, Inc. and Electricite de France International, SA (Designated as Exhibit 10.7 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)

*10(aa) — Letter Agreement dated April 21, 2009 among Constellation Energy Group, Inc., EDF Development Inc. and E.D.F. International S.A. (Designated as Exhibit No. 10(i) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

*10(bb) — Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10.6 to the Current Report on Form 8-K dated December 17, 2008, File No. 1-12869.)

*10(cc) — Amendment No. 1, dated as of April 15, 2009, to the Second Amended and Restated Credit Agreement, dated as of December 17, 2008, among Constellation Energy Group, Inc., the Lenders named therein, Wachovia Bank, National Association, as Administrative Agent, LC Bank, Swingline Lender and Collateral Agent. (Designated as Exhibit No. 10(h) to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, File Nos. 1-12869 and 1-1910.)

12(a) — Constellation Energy Group, Inc. and Subsidiaries Computation of Ratio of Earnings to Fixed Charges.

12(b) — Baltimore Gas and Electric Company and Subsidiaries Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.

21 — Subsidiaries of the Registrant.

23 — Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

31(a) — Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(b) — Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(c) — Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(d) — Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32(a) — Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(b) — Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(c) — Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32(d) — Certification of Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99(a) — Audited Financial Statements of Constellation Energy Nuclear Group, LLC.

*99(b) — Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)

*99(c)	—	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., BGE and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
*99(d)	—	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, File Nos. 1-12869 and 1-1910.)
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Taxonomy Extension Schema Document
101.PRE	—	XBRL Taxonomy Presentation Linkbase Document
101.LAB	—	XBRL Taxonomy Label Linkbase Document
101.CAL	—	XBRL Taxonomy Calculation Linkbase Document
101.DEF	—	XBRL Taxonomy Definition Linkbase Document

+ Management contracts or compensatory plan or arrangement.

* Incorporated by Reference.

In accordance with Rule 402 of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

Exhibit 12(a)

CONSTELLATION ENERGY GROUP, INC. AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	12 Months Ended				
	December 2009	**December 2008**	**December 2007**	**December 2006**	**December 2005**
			(In millions)		
Income (Loss) from Continuing Operations (Before Extraordinary Loss and Cumulative Effects of Changes in Accounting Principles)	**$4,503.4**	$(1,318.4)	$ 834.4	$ 762.5	$ 548.1
Net (Income) Loss Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**(60.0)**	4.0	(12.0)	(13.9)	(12.2)
Taxes on Income (Loss), Including Tax Effect for BGE Preference Stock Dividends	**2,978.1**	(83.6)	419.2	343.1	155.4
Adjusted Income (Loss)	**$7,421.5**	$(1,398.0)	$1,241.6	$1,091.7	$ 691.3
Fixed Charges:					
Interest and Amortization of Debt Discount and Expense and Premium on all Indebtedness, Net of Amounts Capitalized	**$ 352.9**	$ 350.5	$ 292.8	$ 315.9	$ 297.6
Earnings Required for BGE Preference Stock Dividends	**21.8**	23.9	22.3	21.1	21.6
Capitalized Interest and Allowance for Funds Used During Construction	**87.1**	50.0	19.4	13.7	9.9
Interest Factor in Rentals	**71.7**	96.5	96.7	4.5	6.1
Total Fixed Charges	**$ 533.5**	$ 520.9	$ 431.2	$ 355.2	$ 335.2
Amortization of Capitalized Interest	**$ 3.9**	$ 3.3	$ 3.5	$ 4.3	$ 3.7
Earnings (Loss) (1)	**$7,871.8**	$ (923.8)	$1,656.9	$1,437.5	$1,020.3
Ratio of Earnings to Fixed Charges	**14.76**	N/A	3.84	4.05	3.04

(1) Earnings (loss) are deemed to consist of income (loss) from continuing operations (before extraordinary items, cumulative effects of changes in accounting principles, and income (loss) from discontinued operations) that includes earnings of Constellation Energy's consolidated subsidiaries, equity in the net income of unconsolidated subsidiaries, income taxes (including deferred income taxes, investment tax credit adjustments, and the tax effect of BGE's preference stock dividends), and fixed charges (including the amortization of capitalized interest but excluding the capitalization of interest).

N/A Due to the loss for the twelve months ended December 31, 2008, the ratio coverage was less than 1:1. We would have needed to generate additional earnings of $1,444.7 million to achieve a ratio coverage of 1:1.

Exhibit 12(b)

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARIES

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED AND PREFERENCE DIVIDEND REQUIREMENTS

	12 Months Ended				
	December 2009	December 2008	December 2007	December 2006	December 2005
			(In millions)		
Income from Continuing Operations (Before Extraordinary Loss)	**$ 90.7**	$ 51.5	$139.8	$170.3	$189.0
Taxes on Income	**63.8**	20.7	96.0	102.2	119.9
Adjusted Income	**$154.5**	$ 72.2	$235.8	$272.5	$308.9
Fixed Charges:					
Interest and Amortization of Debt Discount and Expense and Premium on all Indebtedness, Net of Amounts Capitalized	**$143.6**	$144.2	$127.9	$104.6	$ 95.6
Interest Factor in Rentals	**0.3**	0.3	0.3	0.3	0.3
Total Fixed Charges	**$143.9**	$144.5	$128.2	$104.9	$ 95.9
Preferred and Preference Dividend Requirements: (1)					
Preferred and Preference Dividends	**$ 13.2**	$ 13.2	$ 13.2	$ 13.2	$ 13.2
Income Tax Required	**8.6**	5.3	9.1	8.0	8.4
Total Preferred and Preference Dividend Requirements	**$ 21.8**	$ 18.5	$ 22.3	$ 21.2	$ 21.6
Total Fixed Charges and Preferred and Preference Dividend Requirements	**$165.7**	$163.0	$150.5	$126.1	$117.5
Earnings (2)	**$298.4**	$216.7	$364.0	$377.4	$404.8
Ratio of Earnings to Fixed Charges	**2.07**	1.50	2.84	3.60	4.22
Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements	**1.80**	1.33	2.42	2.99	3.45

(1) Preferred and preference dividend requirements consist of an amount equal to the pre-tax earnings that would be required to meet dividend requirements on preferred stock and preference stock.

(2) Earnings are deemed to consist of income from continuing operations (before extraordinary loss) that includes earnings of BGE's consolidated subsidiaries, income taxes (including deferred income taxes and investment tax credit adjustments), and fixed charges other than capitalized interest.

Exhibit 21

SUBSIDIARIES OF CONSTELLATION ENERGY GROUP, INC.*

	Jurisdiction of Incorporation
Baltimore Gas and Electric Company	Maryland
Constellation Holdings, Inc.	Maryland
Constellation Investments, Inc.	Maryland
Constellation Power, Inc.	Maryland
Constellation Real Estate Group, Inc.	Maryland
Constellation Enterprises, Inc.	Maryland
Constellation Energy Commodities Group, Inc.	Delaware
Constellation Energy Projects & Services Group, Inc.	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
BGE Home Products & Services, Inc.	Maryland
Constellation Energy Resources, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear, LLC	Maryland
Constellation Energy Nuclear Group, LLC	Maryland
Calvert Cliffs Nuclear Power Plant, Inc.	Maryland
Constellation Power Source Generation, Inc.	Maryland
Constellation Power Source Holdings, Inc.	Maryland
BGE Capital Trust II	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
R.E. Ginna Nuclear Power Plant, LLC	Maryland

* *The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(w) of Regulation S-X.*

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Constellation Energy Group, Inc.

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 and Form S-8 (Nos. 333-157637 and 333-157693 and 33-59545, 333-46980, 333-89046, 333-129802, and 333-143260, respectively) of Constellation Energy Group, Inc. of our report dated February 26, 2010 relating to the financial statements, financial statement schedule, and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP

Baltimore, Maryland
February 26, 2010

Baltimore Gas and Electric Company

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-157637-01) of Baltimore Gas and Electric Company of our report dated February 26, 2010 relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP

Baltimore, Maryland
February 26, 2010

Exhibit 31(a)

CONSTELLATION ENERGY GROUP, INC.

CERTIFICATION

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this report on Form 10-K of Constellation Energy Group, Inc.;

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 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: February 26, 2010

/s/ MAYO A. SHATTUCK III

Chairman of the Board, President and Chief Executive Officer

Exhibit 31(b)

CONSTELLATION ENERGY GROUP, INC.

CERTIFICATION

I, Jonathan W. Thayer, certify that:

1. I have reviewed this report on Form 10-K of Constellation Energy Group, Inc.;

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 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: February 26, 2010

/s/ JONATHAN W. THAYER

Senior Vice President and Chief Financial Officer

Exhibit 31(c)

BALTIMORE GAS AND ELECTRIC COMPANY

CERTIFICATION

I, Kenneth W. DeFontes, Jr., certify that:

1. I have reviewed this report on Form 10-K of Baltimore Gas and Electric Company;

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 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: February 26, 2010

/s/ KENNETH W. DEFONTES, JR.

President and Chief Executive Officer

BALTIMORE GAS AND ELECTRIC COMPANY

CERTIFICATION

I, Kevin W. Hadlock, certify that:

1. I have reviewed this report on Form 10-K of Baltimore Gas and Electric Company;

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 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: February 26, 2010

/s/ KEVIN W. HADLOCK

Senior Vice President and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Mayo A. Shattuck III, Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2009 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

/s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III
Chairman of the Board, President and Chief Executive Officer

Date: February 26, 2010

Exhibit 32(b)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Jonathan W. Thayer, Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc., certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2009 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Constellation Energy Group, Inc.

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Senior Vice President and Chief Financial Officer

Date: February 26, 2010

Exhibit 32(c)

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Kenneth W. DeFontes, Jr., President and Chief Executive Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2009 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ KENNETH W. DEFONTES, JR.

Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Date: February 26, 2010

Exhibit 32(d)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin W. Hadlock, Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company, certify pursuant to 18 U.S.C. Section 1350 adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that to my knowledge:

(i) The accompanying Annual Report on Form 10-K for the year ended December 31, 2009 fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in such report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ KEVIN W. HADLOCK

Kevin W. Hadlock
Senior Vice President and Chief Financial Officer

Date: February 26, 2010

Exhibit No. 99(a)

Consolidated Financial Statements

For the Period November 6, 2009
Through December 31, 2009

Constellation Energy Nuclear Group, LLC
Table of Contents
December 31, 2009

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Members of
Constellation Energy Nuclear Group, LLC:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, changes in members' equity and comprehensive income and of cash flows present fairly, in all material respects, the financial position of Constellation Energy Nuclear Group, LLC and its subsidiaries ("the Company") at December 31, 2009, and the results of their operations and their cash flows for the period from November 6, 2009 to December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements 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 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

The results of operations and cash flows of the Company are presented for the period November 6, 2009 to December 31, 2009 subsequent to the transaction described in Note 1. As discussed in Note 2 to the financial statements, the Company has entered into significant transactions with its related parties.

PricewaterhouseCoopers LLP
Baltimore, Maryland
February 23, 2010

Constellation Energy Nuclear Group, LLC
Consolidated Statement of Income

	For the period November 6 through December 31, 2009 (In Thousands of U.S. Dollars)
Revenues	
Sales under power purchase agreements (PPA):	
Constellation Energy Commodities Group, Inc. (CECG)	$ 122,478
EDF Trading North America, LLC	7,642
Unrelated parties	59,332
Non-PPA sales to unrelated parties	2,408
Capacity and ancillary services revenues from unrelated parties	25,698
Total revenues	217,558
Expenses	
Amortization of nuclear fuel	24,068
Department of Energy waste disposal fees	4,945
Independent system operator charges	752
Compensation-related expenses	47,310
Contractual services, professional services, and staff augmentation	14,573
Administrative support services from Constellation Energy Group, Inc.	11,647
CECG power services agency agreement	2,691
Depreciation	17,160
Accretion of asset retirement obligations	11,257
Property taxes	8,447
Other expenses	13,891
Less amounts reimbursed by Long Island Power Authority	(3,788)
Total expenses	152,953
Operating Income	64,605
Other Income	
Net earnings on nuclear decommissioning trust funds	5,216
Provision for income taxes on nuclear decommissioning trust fund earnings	(1,333)
Interest income	31
Total other income	3,914
Net Income	$ 68,519

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

Constellation Energy Nuclear Group, LLC
Consolidated Balance Sheet

	December 31, 2009 (In Thousands of U.S. Dollars)
Assets	
Current Assets	
Cash and cash equivalents	$ 222,443
Accounts receivable from the sale of power:	
Constellation Energy Commodities Group, Inc. (CECG)	69,205
EDF Trading North America, LLC	7,261
Unrelated parties	43,885
Other receivables:	
UniStar Nuclear Energy, LLC	4,265
Subsidiaries of Constellation Energy Group (CEG)	535
Unrelated parties	5,845
Spare parts, materials, and supplies	137,453
Prepaid expenses and other current assets	20,637
Current portion of Ginna power purchase agreement (Note 7)	1,445
Total current assets	512,974
Investments and Other Noncurrent Assets	
Nuclear decommissioning trust funds	1,244,683
Nuclear fuel - net of amortization	511,857
Ginna power purchase agreement	11,850
Deferred costs of CECG power services agency agreement	3,726
Other noncurrent assets	302
Total investments and other noncurrent assets	1,772,418
Property, Plant, and Equipment	
Plant in service	3,565,734
Accumulated depreciation	(1,188,174)
Net plant in service	2,377,560
Construction work in progress	254,197
Total property, plant, and equipment	2,631,757
Total Assets	**$ 4,917,149**

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

Constellation Energy Nuclear Group, LLC
Consolidated Balance Sheet

		December 31, 2009 (In Thousands of U.S. Dollars)
Liabilities and Members' Equity		
Current Liabilities		
Accounts payable and accrued liabilities:		
Unrelated parties	$	166,211
CEG and subsidiaries of CEG		13,976
Current portion of postretirement and postemployment benefit obligations		5,466
Current portion of power purchase agreement with CECG		371,276
Total current liabilities		556,929
Noncurrent Liabilities		
Asset retirement obligations		1,036,399
Power purchase agreement with CECG		400,854
Pension obligations		172,549
Postretirement and postemployment benefit obligations		94,122
Deferred income taxes on nuclear decommissioning trust funds		11,816
Other noncurrent liabilities		355
Total noncurrent liabilities		1,716,095
Leases, Commitments, Guarantees, and Contingencies (see Notes 9 and 10)		
Members' Equity		
Members' capital		2,987,752
Accumulated deficit		(362,392)
Accumulated other comprehensive income (loss)		18,765
Total members' equity		2,644,125
Total Liabilities and Members' Equity	**$**	**4,917,149**

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

Constellation Energy Nuclear Group, LLC
Consolidated Statement of Cash Flows

		For the period November 6 through December 31, 2009 (In Thousands of U.S. Dollars)
Cash Flows From Operating Activities		
Net Income	$	68,519
Adjustments to reconcile to net cash provided by operating activities:		
Amortization of nuclear fuel		24,068
Depreciation		17,160
Amortization of Ginna power purchase agreement		(882)
Accretion of asset retirement obligations		11,257
Net earnings on nuclear decommissioning trust funds		(5,216)
Provision for income taxes on nuclear decommissioning trust fund earnings		1,333
Defined benefit obligation expense		6,676
Defined benefit obligation payments		(1,202)
Long-term incentive plan compensation		778
Changes in:		
Accounts receivable		(76,747)
Spare parts, materials, and supplies		(3,585)
Prepaid expenses and other current assets		9,568
Deferred costs of CECG power services agency agreement		(3,726)
Accounts payable and accrued liabilities		10,290
Net cash provided by operating activities		58,291
Cash Flows From Investing Activities		
Investments in property, plant, and equipment		(34,493)
Purchases of nuclear fuel		(12,760)
Investments in nuclear decommissioning trust fund securities		(30,697)
Proceeds from the sale of nuclear decommissioning trust fund securities		30,697
Net cash used in investing activities		(47,253)
Cash Flows From Financing Activities		
Distributions to members		(13,515)
Net cash used in financing activities		(13,515)
Net Decrease in Cash and Cash Equivalents		(2,477)
Cash and Cash Equivalents at Beginning of Period		224,920
Cash and Cash Equivalents at End of Period	$	222,443

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

Constellation Energy Nuclear Group, LLC
Consolidated Statement of Changes in Members' Equity and Comprehensive Income

	Members' Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Members' Equity
	(In Thousands of U.S. Dollars)			
Balance, November 6, 2009	$ 2,986,974	$ (417,396)	$ (25,133)	$ 2,544,445
Comprehensive income:				
Net income		68,519		68,519
Other comprehensive income (OCI):				
Change in unrealized gains on nuclear decommissioning trust funds, net of taxes of $5,434			27,065	27,065
Reclassification of net losses on nuclear decommissioning trust funds from OCI to net income, net of taxes of $77			610	610
Gain arising during period on defined benefit plans			14,150	14,150
Amortization of net actuarial loss, net prior service cost, and transition obligation included in net periodic benefit cost			2,073	2,073
Total comprehensive income		68,519	43,898	112,417
Contribution for long-term incentive plan *	778			778
Distributions		(13,515)		(13,515)
Balance, December 31, 2009	**$ 2,987,752**	**$ (362,392)**	**$ 18,765**	**$ 2,644,125**

* Represents noncash transactions with members associated with employees' long -term incentive plan awards.

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

1. Organization and Business

Formation and Organization of the Company

Constellation Energy Nuclear Group, LLC ("CENG" or "the Company") is a Maryland limited liability company formed on December 15, 1999 and reorganized on November 6, 2009. The Company's members and their respective member interests are as follows: 49.11% by Constellation Nuclear, LLC ("CNL"), 0.90% by CE Nuclear, LLC ("CEN"), and 49.99% by EDF Inc. ("EDFI") (formerly EDF Development, Inc.), all of which are Delaware limited liability companies. CNL and CEN are ultimately wholly owned subsidiaries of Constellation Energy Group, Inc. ("CEG"), which, through its interests in CNL and CEN, owns 50.01% of the Company. EDFI is a wholly owned subsidiary of E.D.F. International S.A. ("EDF International"), which is ultimately a wholly owned subsidiary of Electricité de France, SA ("EDF").

EDFI acquired its member interest in the Company effective 10:00 AM Eastern Standard Time on November 6, 2009 (the "EDF Closing"). Prior to this date, the Company was a wholly owned subsidiary of CEG. The results of operations and cash flows of the Company are presented for the period November 6 through December 31, 2009 subsequent to the transaction. The Company carried forward its historical basis of assets and liabilities as a result of this transaction.

The operation of the Company is subject to various agreements among the members, including the Second Amended and Restated Operating Agreement dated November 6, 2009 (the "Operating Agreement"). These agreements include provisions which describe, among other matters, the formation and termination of the Company, the rights and responsibilities of the members, the operating activities of the Company, the governance of the Company, capital contributions by the members, and profit distributions to the members. The agreements contain mechanisms for the members to contribute additional capital or make loan advances to the Company if needed.

The Company is governed by a board of ten directors, five of which are appointed by CNL and five by EDFI. In addition, the consents of both CNL and EDFI are required before the Company may take certain significant actions, including materially changing the scope of the Company's businesses, issuing credit support outside the ordinary course of business, incurring certain types of indebtedness, and entering into agreements of significant size or duration. In general, the Company is jointly controlled by CEG and EDFI, except for matters related to nuclear safety, security and reliability, certain regulatory and environmental compliance issues, and senior executive officer appointments for which CEG has a casting or controlling vote. No member is obligated individually for any debt, obligation, or liability of the Company solely by reason of being a member of the Company. Only obligations of the Company that are assumed by a member in a separate written agreement can become liabilities of a member. In the event the Company were to be liquidated, the remaining equity of the Company would be divided among the members according to each member's ownership interest.

Nature of the Business

The Company owns and operates three nuclear power plants having a total capacity of 4,044 megawatts ("MW") as set forth below. The 18% of Nine Mile Point Unit 2 (NMP2) not owned by the Company is owned by the Long Island Power Authority ("LIPA"), an unrelated party, which reimburses the Company for its 18% share of the operating and construction costs of that unit. The Company and LIPA are each responsible for providing their own financing for NMP2.

Plant	Location	Region	Total MW	% Owned By the Company	MW Owned By the Company	Expiration Of NRC License	Most Recent Refueling Outage
Calvert Cliffs Unit 1	Calvert County, MD	PJM	855	100%	855	2034	03/2008
Calvert Cliffs Unit 2	Calvert County, MD	PJM	850	100%	850	2036	03/2009
Ginna	Ontario, NY	NYISO	581	100%	581	2029	10/2009
Nine Mile Point Unit 1	Scriba, NY	NYISO	620	100%	620	2029	04/2009
Nine Mile Point Unit 2	Scriba, NY	NYISO	1,138	82%	933	2046	04/2008
			4,044		3,839		

The Calvert Cliffs and Nine Mile Point units are on 24-month refueling outage schedules, and the Ginna plant is on an 18-month refueling outage schedule.

The Company is making investments in Nine Mile Point Unit 2 which are expected to increase the capacity of that unit by 105 MW from 1,138 MW to 1,243 MW effective approximately June of 2012. In January 2010, the Company and LIPA entered into an agreement under which LIPA will participate in 18% of this capacity increase consistent with their existing ownership interest. The costs incurred through December 31, 2009 which were attributable to LIPA's share of the increased capacity were approximately $16.3 million, and LIPA reimbursed the Company for this amount in January 2010. As a result, the Company's and LIPA's ownership interests in Nine Mile Point Unit 2 continue to be 82% and 18%, respectively.

2. Related-Party Transactions

In the normal course of business, the Company conducts transactions with certain related parties under the following agreements.

Power Purchase Agreements

As discussed in Note 7, the power generated by the Company's plants is sold through various Power Purchase Agreements ("PPAs") to Constellation Energy Commodities Group ("CECG"), a wholly owned subsidiary of CEG; EDF Trading North America, LLC ("EDFTNA"), which is ultimately a wholly owned subsidiary of EDF; and unrelated parties.

Administrative Services Agreement

The Company purchases various administrative services from CEG pursuant to a fixed-price contract and a consumption-based contract. The fixed-price contract covers most services at an annual cost of $66 million, and the consumption-based contract covers primarily information technology services. Both contracts expire on December 31, 2010, after which they are to be replaced by a new administrative services agreement that will incorporate a direct-charging mechanism.

Power Services Agency Agreement

The Company purchases certain scheduling, asset management, and billing services from CECG under a power services agency agreement that expires December 31, 2014 (the "Power Services Agency Agreement"). The cost of the Power Services Agency Agreement is charged to expense at the annual rate of approximately $16.1 million. Cumulative scheduled payments under the Power Services Agency Agreement in excess of the expensed amounts are recorded in the Consolidated Balance Sheet as a deferred cost. Payments required for each year of the Power Services Agency Agreement and the related deferred costs at the respective year ends are as follows:

		Year-End Deferred Cost Balance	
Year	**Payments**	**Total**	**Current Portion**
		(In Thousands)	
November 6 through December 31, 2009	$ 6,417	$ 3,726	$ —
2010	42,100	29,681	2,545
2011	13,600	27,135	7,645
2012	8,500	19,490	7,645
2013	8,500	11,845	11,845
2014	4,300	—	—
Total	$ 83,417		

Pension Plan

As discussed in Note 8, pending a final ERISA 4044 evaluation, the assets of one of the Company's pension plans are co-managed with the assets of CEG's pension plan as of December 31, 2009.

Contractual Services Agreements

EDF has seconded certain of its employees to the Company, and the Company has an agreement to reimburse EDF for the costs of these employees. During the period November 6 through December 31, 2009, the Company incurred costs of $84,000 under this agreement. The costs are recorded in "Contractual services, professional services, and staff augmentation" expense.

UniStar Nuclear Energy, LLC ("UNE") is a 50/50 joint venture between subsidiaries of CEG and EDF. The Company has assigned certain of its employees, and provides technical, managerial, and administrative services, to UNE through a cost-reimbursement project billing arrangement. For the period November 6 through December 31, 2009, reimbursable costs were approximately $3.5 million.

Contingent Receipts

As discussed in Note 10, CEG is entitled to any funds received from the U.S. Department of Energy ("DOE") that reimburse costs expended prior to the EDF Closing for the storage of spent nuclear fuel at the Company's nuclear sites.

Parental Guarantees

CEG and EDF have issued or are otherwise responsible for the following guarantees, financial assurances, and letters of credit on behalf of the Company or its operating subsidiaries with respect to various Company or subsidiary obligations in the combined aggregate amount of approximately $980.3 million. CEG and EDF share in these obligations in proportion to their respective member interests.

- $587.5 million in guarantees for the payment of contingent retrospective premium adjustments for the nuclear liability insurance discussed in Note 10;
- $93.5 million in guarantees for the payment of contingent retrospective premium adjustments for the nuclear property and decontamination liability insurance discussed in Note 10;
- $290.0 million in combined support agreement obligations to meet U.S. Nuclear Regulatory Commission ("NRC") requirements;
- $7.2 million in guarantees associated with hazardous waste management facilities, underground storage tanks, and operating within the PJM region; and
- $2.1 million in irrevocable standby letters of credit for workers compensation insurance deductibles.

3. Significant Accounting Policies

Significant accounting policies pertaining to matters discussed in other notes are disclosed in those notes. The following are significant accounting policies not discussed elsewhere.

Basis of Presentation

These consolidated financial statements are presented in United States dollars in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of the Company and all entities controlled by the Company. All material intercompany balances and transactions have been eliminated.

Management evaluated for inclusion in these financial statements events and transactions that occurred after December 31, 2009 through February 26, 2010, the date these financial statements were issued.

Use of Estimates

When preparing financial statements in accordance with GAAP, management makes estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Derivatives

The Company does not have any contracts that meet the definition of a derivative, other than certain PPAs qualifying for the normal purchases and normal sales exception under GAAP which are therefore accounted for on the accrual basis and not reported at fair value.

Fair Value

We determine the fair value of our assets and liabilities using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. We determine fair value measurements classified as Level 1 or Level 2 by multiplying the pricing input by the quantity. We primarily determine fair value measurements classified as Level 3 using the income valuation approach, which involves discounting estimated cash flows using assumptions that market participants would use in pricing the asset or liability.

Income Taxes

The Company's qualified nuclear decommissioning trust funds are subject to federal income taxes as separate taxable entities, and a provision for those taxes is made in these financial statements. No additional provision for income taxes is made in these financial statements because the Company is considered a partnership for income tax purposes and, accordingly, the members are responsible for the income tax consequences of their respective shares of the Company's income, loss, deductions, and credits.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and highly liquid investments with original maturities of three months or less, other than those held in and reported as "Nuclear decommissioning trust funds." Cash and cash equivalents are reported in the Consolidated Balance Sheet at fair value in the Level 1 hierarchy.

Accounts Receivable

Accounts receivable are stated net of any allowance for uncollectibles. At December 31, 2009, the allowance for uncollectibles was not material.

Spare Parts, Materials, and Supplies

Spare parts, materials, and supplies (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are stated at the lower of average cost or market.

Nuclear Fuel

As discussed in Note 9, the Company has long-term contracts for the purchase, conversion, and enrichment of nuclear fuel, the fabrication of fuel rod assemblies, and the procurement of canisters for the storage of spent nuclear fuel. Costs incurred under these contracts are recorded in the Consolidated Balance Sheet as "Nuclear fuel — net of amortization." These contracts do not meet the definition of a derivative or a lease, and the Company accounts for them on the accrual basis. The nuclear fuel and canister costs are amortized based on the energy produced over the life of the fuel in the reactor, and the amortization expense is reported in the Consolidated Statement of Income as "Amortization of nuclear fuel." In addition, fees paid to the DOE for the disposal of spent nuclear fuel are recorded to expense as incurred.

4. Property, Plant, and Equipment

Original Cost

Property, plant, and equipment ("PP&E") is recorded at its original cost, net of accumulated depreciation. Original cost includes the material, labor, and contractor costs directly associated with the acquisition or construction of the PP&E. In addition, as discussed in Note 6, the cost of PP&E includes the associated asset retirement costs. Executive and general management costs are charged to expense, not to PP&E. The costs of capital projects are accumulated in the Consolidated Balance Sheet as "Construction work in progress" until the assets are placed in service.

The smallest item recorded as PP&E is a retirement unit. When a retirement unit is replaced, and in certain circumstances when a retirement unit is refurbished, the cost of the replacement or refurbishment is capitalized. When only part of a retirement unit is replaced or when maintenance (including planned major maintenance) is performed, the cost is charged to expense in the Consolidated Statement of Income.

Certain significant spare parts, defined as Capital Spares or Rotatable Spares, are recorded in "Plant in service" rather than in "Spare parts, materials, and supplies" and are depreciated and otherwise accounted for consistent with other "Plant in service."

Depreciation Expense and Useful Life

Plant buildings and equipment are depreciated using the group straight-line method. Depreciation groups consist of retirement units that are similar in nature and that have approximately the same useful lives. Assets are depreciated through the shorter of their useful lives or the license expiration date of the plant with which the asset is associated. Periodically, depreciation studies are conducted to update the useful lives of the various depreciation groups. PP&E other than plant buildings and equipment is generally depreciated on a straight-line basis. Plant buildings and equipment comprise more than 95% of the carrying value of the Company's PP&E, with computer software, office equipment and furniture, and transportation equipment comprising the remainder of the PP&E. The weighted average annual depreciation rate applied to the gross cost of PP&E at December 31, 2009 was 3.1%.

Retirements

For routine retirements of PP&E depreciated under the group depreciation method, the cost of the asset being retired is removed from both "Plant in service" and "Accumulated depreciation" in the Consolidated Balance Sheet. No gain or loss is recorded for routine retirements because the depreciation rates under the group method contemplate a statistical dispersion of routine retirement activity. For extraordinary retirements not contemplated in the periodic depreciation studies, and for the retirement of other PP&E not depreciated under the group method of depreciation, any disposition gain or loss is recorded in the Consolidated Statement of Income. The cost of removing assets from service is charged to expense as incurred.

Impairment Evaluations

The Company periodically evaluates whether events have occurred or conditions have changed that would indicate a further evaluation is warranted to determine whether its PP&E may be impaired. This evaluation is performed at the lowest level for which identifiable cash flows are largely independent of the cash flows of other groups of assets and liabilities. The PP&E asset groups evaluated for impairment are 1) Calvert Cliffs, 2) Nine Mile Point, 3) Ginna, and 4) the entire Company including headquarters and non-plant PP&E. The PP&E asset groups consist of the plant-specific PP&E, nuclear fuel, and PPA assets and liabilities. An impairment would be indicated if the undiscounted estimated future cash flows are less than the carrying amount of the asset group, in which case the carrying values of the assets and liabilities comprising the impaired PP&E asset group would be adjusted to their fair values, and a corresponding charge would be made in the Consolidated Statement of Income. For the period November 6 through December 31, 2009, none of the Company's PP&E asset groups were impaired.

Nine Mile Point Unit 2

Presented in the Consolidated Balance Sheet for the Company's 82% interest in Nine Mile Point Unit 2 is $410.7 million of plant in service, $92.3 million of accumulated depreciation and $100.6 million of construction work in progress

5. Nuclear Decommissioning Trust Funds

As discussed in Note 6, the Company is obligated to decommission its plants after they cease operation in accordance with NRC regulations and relevant state requirements. In accordance with NRC regulations, the Company maintains external trust funds to fund the costs expected to be incurred to decommission its plants. The nuclear decommissioning trust funds and the investment earnings thereon are restricted to meeting the costs of decommissioning the plants in accordance with NRC regulations and relevant state requirements. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle, and the trusts are prohibited from investing directly in CEG, EDF, their affiliates, or any entity owning a nuclear power plant in the United States.

It is expected that decommissioning activities will be undertaken through early in the 2080 decade. If the actual return on trust fund assets were to be lower than expected, or if the costs or timing of decommissioning activities were to change, the Company could have to provide additional funding, which could have a material adverse effect on the Company's liquidity and financial results. Any shortfall in funding would have to be satisfied by the Company, and any excess would become available for general corporate use or settlement of any non-radiological decommissioning obligations only after all NRC decommissioning obligations are met.

Every two years, the NRC requires U.S. nuclear power generation companies to report the status of the funds and provide reasonable assurance that funds will be available to decommission their sites. The NRC has accepted the Company's 2009 filings as providing reasonable financial assurance, and the Company's next NRC submittal is scheduled to be filed by March 2011.

The trust fund investments are classified as available-for-sale securities and are reported at fair value in the Consolidated Balance Sheet as "Nuclear decommissioning trust funds." The trust fund balances were as follows at December 31, 2009:

	December 31, 2009		
	Adjusted Cost	Pre-Tax Unrealized Gains Recorded in Accumulated Other Comprehensive Income	Fair Value
		(In Thousands)	
Calvert Cliffs	$ 335,316	$ 120,791	$ 456,107
Nine Mile Point	445,839	103,899	549,738
Ginna	179,737	59,101	238,838
Total	$ 960,892	$ 283,791	$ 1,244,683

No contributions or distributions were made to or from any of the trust funds during the period November 6, 2009 through December 31, 2009.

Interest and dividend income net of trust expenses on the trust funds for the period November 6 through December 31, 2009 was $5.9 million. Gross realized gains and gross realized losses were as follows, with cost determined on a tax-lot basis:

	Amount (In Thousands)
Gross realized gains	$ 2,482
Gross realized losses	(3,169)
Net realized losses	$ (687)

The nuclear decommissioning trust fund assets are subject to impairment evaluations. If the market value of a security falls below the security's carrying value, the carrying value is reduced to market value, and a corresponding charge is recorded in the Consolidated Statement of Income within "Net earnings on nuclear decommissioning trust funds." Impairment charges recorded during the period November 6 through December 31, 2009 were approximately $1.4 million and are included in gross realized losses in the table above. In addition, temporary changes in the fair value of the non-impaired trust fund assets are recorded as "Other comprehensive income."

As discussed in Note 3, GAAP provides a hierarchy for measuring fair value for assets recorded at fair value. The following table sets forth, by level within the fair value hierarchy, the fair value of the investments in the nuclear decommissioning trust funds at December 31, 2009:

	Level 1	Level 2 (In Thousands)	Level 3	Total Fair Value at December 31, 2009
Marketable equity securities	$ 344,939	$ —	$ —	$ 344,939
Mutual funds / common collective trusts	5,472	586,199	—	591,671
Corporate debt securities	—	170,195	—	170,195
U.S. government agencies	—	43,249	—	43,249
U.S. treasuries	22,645	—	—	22,645
State municipal bonds	—	54,408	—	54,408
Cash equivalents	—	17,576	—	17,576
Total	$ 373,056	$ 871,627	$ —	$ 1,244,683

The investments in corporate debt securities, U.S. government agencies, U.S. treasuries, and state municipal bonds mature on the following schedule:

	At December 31, 2009 (In Thousands)
Less than 1 year	$ 9,843
1-5 years	95,352
5-10 years	82,456
More than 10 years	102,846
Total maturities of debt securities	$ 290,497

6. Asset Retirement Obligations

The Company incurs legal obligations, known as asset retirement obligations ("AROs"), arising from the requirement to decommission and decontaminate its nuclear generating facilities in connection with their future retirement. These AROs are measured by estimating their present values based upon management's judgment of the probability, amount, and timing of decommissioning payments and the appropriate interest rates to discount these future cash flows to present value.

The ARO measurements are determined utilizing site-specific decommissioning cost estimates which are updated periodically. The Company believes these estimates continue to be reasonable as of December 31, 2009. However, given the magnitude of the amounts involved, the complicated and ever-changing technical and regulatory requirements, and the long time horizons involved, the actual obligation could vary from the assumptions used in management's estimates, and the impact of such variations could be material.

When an ARO liability is recorded, a corresponding increase to the related long-lived asset is also recorded. When changes in the assumptions used to calculate the fair value of existing AROs result in a material change to the existing carrying value, the carrying values of both the ARO liability and the related long-lived asset are adjusted.

Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized in the Consolidated Statement of Income as "Accretion of asset retirement obligations" until the settlement of the liability. When the liability is finally settled, a gain or loss will be recorded for any difference between the recorded liability and the actual costs incurred.

The following is a summary of the Company's ARO liabilities:

Plant		December 31, 2009 (In Thousands)
Calvert Cliffs	$	359,197
Nine Mile Point		396,929
Ginna		280,273
Total	$	1,036,399

The change in the ARO liability for the period November 6 through December 31, 2009 was as follows:

ARO Rollforward		Amount (In Thousands)
Liability at November 6, 2009	$	1,025,142
Accretion expense		11,257
Liability at December 31, 2009	$	1,036,399

7. Power Purchase Agreements and Revenue Sharing Agreements

Power Purchase Agreements

The Company earns revenue primarily from the sale of power from its plants under its PPAs. Energy, capacity, and ancillary services not sold under PPAs are sold to independent system operators ("ISOs") at day-ahead market prices. The PPAs either do not meet the definition of a derivative or qualify for derivative accounting's normal purchases and normal sales exception under GAAP. As a result, revenue is recorded on the accrual method in the period when the Company physically delivers electricity.

The Company has a fixed-price unit-contingent PPA expiring in June 2014 with the former owner of the Ginna plant for approximately 90% of the available energy output from the Ginna plant. The Ginna PPA was executed in November 2003 at prices other than market, and it became effective upon the closing of the acquisition of Ginna in June 2004. Accordingly, the Ginna PPA was recorded in the Consolidated Balance Sheet at fair value at the time of execution, and the existing above-market value is being amortized against revenue over the remaining term of the contract.

The Company has four fixed-price unit-contingent PPAs expiring in November 2011 with the former owners of Nine Mile Point Unit 2 (NMP2) for a total of 90% of the Company's 82% share of the available energy from NMP2. Because these PPAs were at market value when they became effective in November 2001, the Company did not record a PPA asset or liability in the Consolidated Balance Sheet.

On November 6, 2009, the Company entered into five PPAs with CECG and five PPAs with EDFTNA for substantially all of the energy available from its plants after fulfilling its obligations under the Ginna PPA and NMP2 PPAs. These CECG and EDFTNA PPAs expire in December 2014 and require the physical delivery of power, except during planned outages. In the event of an unplanned outage, the Company is required to purchase power in the open market to meet its obligations under the PPAs. Under these PPAs, the Company has the ability to fix the price of a portion of the available energy, with any remaining power sold in the spot market at day-ahead prices, and the Company has fixed the price for certain portions of future available energy. The split of available energy between CECG and EDFTNA after the Company fulfills its obligations under the Ginna PPA and the NMP2 PPAs is as set forth below:

PPAs Energy Split	2010	2011	2012-2014
CECG PPAs	90%	87.5%	85%
EDFTNA PPAs	10%	12.5%	15%
Total available	100%	100%	100%

The CECG PPAs were structured at below-market prices at inception for 2010 and 2011. The fair values of the PPAs were determined using Level 2 inputs and totaled approximately $772.1 million. The Company recorded this amount in the Consolidated Balance Sheet as "Power purchase agreement with CECG" and will amortize it into revenue over the two-year period beginning January 1, 2010 based on the terms of the contracts.

The table below presents the estimated favorable (unfavorable) non-cash effect on revenues of the amortization of the CECG PPA liabilities and the Ginna PPA asset:

Year Ended December 31,	2010	2011	2012	2013	2014	Total
			(In Thousands)			
CECG PPA liability amortization	$ 371,276	$ 400,854	$ —	$ —	$ —	$ 772,130
Ginna PPA asset amortization	(1,445)	(2,152)	(3,205)	(3,881)	(2,611)	(13,294)
Net PPA amortization	$ 369,831	$ 398,702	$ (3,205)	$ (3,881)	$ (2,611)	$ 758,836

Revenue Sharing Agreements

In connection with the purchase of Nine Mile Point Unit 2, the Company entered into 10-year unit-contingent revenue sharing agreements ("RSAs") with the former owners of that unit (the "Former NMP2 Owners"). The RSAs, which apply only to the 82% of the unit owned by the Company, will become effective upon the expiration of the NMP2 PPAs and will expire in November 2021. Under the RSAs, the Company is required to pay to the Former NMP2 Owners 80% of the positive spread, if any, between the actual revenues per MWh earned by NMP2 and the RSA floor price per MWh for the period. The floor price starts at $40.75/MWh in RSA contract year 1 (December 2011 — November 2012) and increases two percent annually over the 10-year term. The Company will record any amounts earned by the Former NMP2 Owners under the RSAs as expense in the periods incurred.

8. Employee Benefit Plans

The Company sponsors several defined-benefit pension, postretirement, and other postemployment benefit plans, as well as contributory employee savings plans (the "plans"). Prior to the EDF Closing, CENG employees other than Nine Mile Point employees had participated in CEG's defined benefit plans. Effective November 6, 2009, CEG transferred the defined benefit obligations for these plans, at historical cost, to the Company. Employees of the Nine Mile Point plant are covered by one set of plans (the "CENG-NMP Plans"), and the rest of the Company's employees (Calvert Cliffs, Ginna, and the headquarters staff) are covered by another set of plans (the "CENG Plans"). At December 31, 2009, these plans include only qualified plans in which most employees are eligible to participate. Each of the plans is described below, and the benefits under the defined-benefit plans are calculated generally based on age, years of service, and pay. For each plan, the measurement date is December 31, 2009.

Pension Benefits

The Company maintains one pension plan for its Nine Mile Point employees (the "CENG-NMP Pension Plan") and another pension plan for the rest of the Company's employees (the "CENG Pension Plan"). On November 6, 2009, the assets of the CENG Pension Plan were segregated to a master trust sub-account within CEG's pension plan master trust based on an initial calculation under section 4044 of ERISA. The assets are expected to be transferred to CENG's separate master trust following the final ERISA 4044 evaluation, approval by CENG and its members, and the formation of the Company's investment committee. At that time, the assets of both of the Company's pension plans will be managed separately from those of CEG. Until then, they will be co-managed with the assets of CEG's pension plan. The design of the CENG Plans is identical to the design of the CEG plans with no changes in benefit formulas or plan amendments during the period November 6 through December 31, 2009.

At December 31, 2009, both pension plans are qualified plans under IRS regulations. The Company funds the qualified plans by contributing at least the minimum amount required under IRS regulations. The amount of funding is calculated using the projected unit credit cost method. During 2010, the Company expects to contribute approximately $14.0 million and $34.3 million to the CENG-NMP Pension Plan and the CENG Pension Plan, respectively.

Postretirement and Other Postemployment Benefits

The following table summarizes the defined postretirement and other postemployment benefit obligations in the Consolidated Balance Sheet:

	December 31, 2009 (In Thousands)
Postretirement benefits	$ 91,478
Postemployment benefits	8,110
Total postretirement and other postemployment benefit obligations	99,588
Less amount recorded in current liabilities	(5,466)
Total noncurrent postretirement and other postemployment benefit obligations	$ 94,122

Postretirement Benefits

The Company sponsors defined-benefit postretirement health care and life insurance plans that cover the majority of its employees. Generally, the benefits under these plans are calculated based on age, years of service, and pension benefit levels or final base pay. The Company does not fund these plans. Almost all of the retirees make contributions to cover a portion of the medical plan costs, but retirees do not make contributions to cover the costs of the life insurance plan. The Company's contributions for retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 are capped at the 2002 level except for Nine Mile Point retirees. Company medical contributions for Nine Mile Point retirees are capped at 2009 levels, and union employees hired after the end of the last contract in 2006 are not eligible for retiree medical benefits.

Other Postemployment Benefits

The Company provides the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under the Disability Insurance Plan, and
- income replacement payments for Nine Mile Point union-represented employees determined to be disabled.

The Company recognized expense associated with its other postemployment benefits of $48,000 for the period November 6 through December 31, 2009.

The assumed discount rate for other postemployment benefits was 4.75% at December 31, 2009.

Employee Savings Plan Benefits

The Company sponsors defined-contribution employee savings plans that are offered to all eligible employees. The plans are qualified 401(k) plans under the Internal Revenue Code. The Company makes matching contributions in cash to participant accounts under these plans; these matching contributions totaled approximately $1.0 million for the period November 6 through December 31, 2009.

Liability Adjustments for Pension Plans

The pension obligations for the Company's qualified pension plans were greater than the fair value of its pension plan assets as follows:

At December 31, 2009	CENG-NMP Plan	CENG Plan (In Thousands)	Total
Accumulated benefit obligation	$ 157,653	$ 207,308	$ 364,961
Fair value of assets	109,888	128,760	238,648
Unfunded obligation	$ 47,765	$ 78,548	$ 126,313

The Company is required to reflect the funded status of its pension plans in terms of the projected benefit obligation ("PBO"), which is higher than the accumulated benefit obligation ("ABO") because the PBO includes the impact of expected future compensation increases on the pension obligation.

At December 31, 2009	CENG-NMP Plan	CENG Plan (In Thousands)	Total
Projected benefit obligation	$ 167,074	$ 244,123	$ 411,197
Fair value of assets	109,888	128,760	238,648
Unfunded obligation	$ 57,186	$ 115,363	$ 172,549

Changes in Projected Benefit Obligations and Assets of the Pension and Postretirement Plans

The following tables show the changes in the projected benefit obligations and plan assets of the pension and postretirement benefit plans.

	For the Period November 6 Through December 31, 2009	
	Pension Benefits	Postretirement Benefits
	(In Thousands)	
Change in Projected Benefit Obligations:		
Benefit obligation at November 6, 2009	$ 410,465	$ 98,596
Service cost	2,751	795
Interest cost	3,507	847
Contributions by participants	—	206
Medicare reimbursement	—	30
Actuarial gain	(3,662)	(7,788)
Benefits paid, including both annuity payments and lump-sum distributions	(1,864)	(1,208)
Benefit obligation at December 31, 2009	411,197	91,478
Change in Plan Assets:		
Fair value of plan assets at November 6, 2009	234,367	—
Actual return on plan assets	6,145	—
Employer contribution	—	972
Plan participants' contributions	—	206
Medicare Part D reimbursement	—	30
Benefits paid, including both annuity payments and lump-sum distributions	(1,864)	(1,208)
Fair value of plan assets at December 31, 2009	238,648	—
Liability at December 31, 2009	$ 172,549	$ 91,478

Net Periodic Benefit Cost and Amounts Recognized in Other Comprehensive Income

The following table shows the components of net periodic benefits cost combined for the CENG-NMP Pension Plan and the CENG Pension Plan:

Components of Net Periodic Benefit Cost	For the period November 6 through December 31, 2009 Pension Benefits	Postretirement Benefits
	(In Thousands)	
Service cost	$ 2,751	$ 795
Interest cost	3,507	847
Expected return on plan assets	(3,445)	—
Amortization of unrecognized prior service cost	171	(148)
Recognized net actuarial loss	1,781	259
Transition obligation	—	9
Amount capitalized as construction cost	(176)	(54)
Net periodic benefit cost	$ 4,589	$ 1,708

The following is a summary of the pension and postretirement amounts combined for the CENG-NMP Plans and the CENG Plans that the Company has recorded in "Accumulated other comprehensive income" ("AOCI") and the expected amortization of those amounts over the next year:

AOCI Pension Benefits	December 31, 2009	Expected Amortization 2010
	(In Thousands)	
Actuarial loss	$ 199,390	$ 10,840
Prior service cost	4,005	862
Total	$ 203,395	$ 11,702

AOCI Postretirement Benefits	December 31, 2009	Expected Amortization 2010
	(In Thousands)	
Actuarial loss	$ 18,042	$ 1,100
Prior service cost	(5,227)	(965)
Transition obligation	178	59
Total	$ 12,993	$ 194

Expected Cash Benefit Payments

The pension and postretirement benefits the Company expects to pay in each of the next five years and in the aggregate for the subsequent five years for both plans are shown below. These estimated benefits are based on the same assumptions used to measure the benefit obligations at December 31, 2009, but include benefits attributable to estimated future employee service.

		Postretirement Benefits		
Year(s)	Pension Benefits	Before Medicare Part D	Medicare Part D Subsidy	After Medicare Part D
	(In Thousands)			
2010	$ 27,083	$ 4,511	$ (68)	$ 4,443
2011	26,120	5,025	(93)	4,932
2012	29,823	5,405	(135)	5,270
2013	34,848	6,040	(177)	5,863
2014	41,221	6,680	(214)	6,466
2015-2019	232,129	40,887	(1,515)	39,372

Assumptions for Pension and Postretirement Benefit Obligations and Periodic Cost

The Company made the following assumptions in calculating its pension and postretirement obligations and periodic costs at December 31, 2009 based upon the investment strategy, asset mix target, and expected returns for each asset class in CEG's pension plan, since the Company's pension plans are currently managed by CEG's Investment Committee:

	December 31, 2009		
	Pension Benefits	Postretirement Benefits	Assumption Impacts Calculation of
Discount rate	6.00%	6.50%	Benefit obligation and periodic cost
Expected return on plan assets	8.50%	N/A	Periodic cost
Rate of compensation increase for CENG-NMP Plan and CENG Plan, respectively	3.55%/4.00%	3.55%/4.00%	Benefit obligation and periodic cost

The discount rate is based on an analysis of high quality corporate bonds whose maturities match the Company's expected benefit payments. The 8.50% overall expected long-term rate of return on plan assets reflects the Company's long-term investment strategy in terms of asset mix targets and expected returns for each asset class for this period.

The Company assumed health care inflation rates of 8.00% and 7.50% for 2010 and 2011, respectively, with an ultimate trend rate of 5.00% to be reached in 2016.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $3.5 million at December 31, 2009 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $99,000 annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $2.8 million at December 31, 2009 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $78,000 annually.

Qualified Pension Plan Assets

Investment Strategy

The Company invests its qualified pension plan assets using the following investment objectives:

- ensure availability of funds for payment of plan benefits as they become due,
- provide for a reasonable amount of long-term growth of capital without excessive volatility,
- produce investment results that meet or exceed the assumed long-term rate of return, and
- improve the funded status of the plan over time.

The Company will establish its own Investment Committee which will be responsible for oversight over both the plans and the adoption of an investment strategy to achieve these investment objectives. Currently, CEG's Investment Committee holds these responsibilities.

Asset Allocation

The asset allocation shown below is based on the results of a 2009 asset-liability study prior to November 6, 2009. This asset allocation policy is long-term oriented and consistent with the funding status of the plans.

The Company's target asset allocations as well as the actual 2009 allocations for CEG's qualified pension plans were as follows:

At December 31, 2009	Target Allocation	Actual Allocation
Global equity securities	48%	57%
Fixed income securities	30	27
Alternative investments	15	7
High-yield bonds	7	7
Cash and cash equivalents	—	2
Total	100%	100%

Following the establishment of the Company's Investment Committee, the investment strategy, assumed long-term returns, and the above target asset allocation will be reassessed and the pension plan portfolio will be rebalanced accordingly. Thereafter, the portfolio will be rebalanced whenever the actual allocations fall outside of the target ranges. For the long-term, the Company will rebalance to de-risk the portfolio as the funded status improves.

The Company determines expected return on plan assets using a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

Fair Value of Pension Plan Assets

The following table sets forth, by level within the fair value hierarchy discussed in Note 3, the combined investments in the Pension Plans' master trust at fair value at December 31, 2009 for the CENG-NMP Pension Plan and CENG Pension Plan:

	Level 1	Level 2	Level 3	Total Fair Value at December 31, 2009
		(In Thousands)		
Global equity securities	$ 48,586	$ 86,372	$ —	$ 134,958
Fixed income securities	—	65,224	—	65,224
Alternative investments	—	—	16,785	16,785
High yield bonds	125	17,067	—	17,192
Cash equivalents	—	4,489	—	4,489
Total	$ 48,711	$ 173,152	$ 16,785	$ 238,648

The above distribution by type of investment and fair value classification is based upon CENG's 18.4% share of the total market value of the master trust.

The following table sets forth a summary of changes in the fair value of the Level 3 assets for the period November 6 through December 31, 2009:

	For the Period November 6 Through December 31, 2009 (In Thousands)
Balance at beginning of period	$ 16,126
Realized gains	162
Unrealized gains	490
Assets sold during the year	(431)
Purchases, sales and settlements	98
Transfers into and out of Level 3	340
Balance at end of period	$ 16,785

9. Leases, Commitments, and Guarantees

Leases

The Company is the lessee under certain facilities and equipment lease agreements which expire on various dates and have various renewal options. All leases are classified as operating leases. The Company included approximately $536,000 of expense related to its operating leases in the Consolidated Statement of Income for the period November 6 through December 31, 2009.

Commitments

The Company has made substantial commitments in connection with the operation of its plants relating to the procurement of nuclear fuel, long-term service agreements, capital for construction programs, and other purchases.

Nuclear Fuel

The Company has long-term contracts for the purchase, conversion, and enrichment of nuclear fuel, and the fabrication of fuel rod assemblies. These commitments provide for quantities to substantially meet the Company's expected requirements for the next several years. These contracts expire between 2010 and 2028. The nuclear fuel markets are competitive and prices can be volatile, but management does not anticipate problems in meeting the Company's future supply requirements.

Other Long-Term Agreements

The Company has multi-year commitments in connection with various construction projects, the procurement of canisters for the disposal of spent nuclear fuel, other long-term service agreements, and other purchase commitments for its plants.

At December 31, 2009, management estimates that the Company's future obligations on existing commitments will be as set forth below:

	2010	2011	2012	2013	2014	Thereafter	Total
				(In Thousands)			
Operating leases	$ 3,237	$ 1,210	$ 1,228	$ 1,045	$ 539	$ 180	$ 7,439
Nuclear fuel contracts	195,070	223,034	190,546	219,860	121,100	1,791,835	2,741,445
Power services agency agreement with CECG (see Note 2)	42,100	13,600	8,500	8,500	4,300	—	77,000
Administrative services agreements with CEG (see Note 2)	66,000	—	—	—	—	—	66,000
Long-term service contracts, capital projects, nuclear fuel canisters, etc.	60,289	56,771	20,409	7,427	10,187	8,505	163,588
Total future obligations	$ 366,696	$ 294,615	$ 220,683	$ 236,832	$136,126	$1,800,520	$ 3,055,472

Guarantees

The Company's guarantees do not represent incremental obligations. Instead, they represent parental guarantees of the obligations of its consolidated operating subsidiaries. At December 31, 2009, the Company guaranteed the following on behalf of its consolidated operating subsidiaries:

- a total of $681 million for the contingent payment obligation of the nuclear liability insurance retrospective premiums discussed in Note 10,
- the remaining $77 million of the payment obligations under the Power Services Agency Agreement with CECG discussed in Note 2, and
- the payment obligations resulting from non-performance under the power purchase agreements with CECG and EDFTNA discussed in Note 7.

10. Contingencies

Storage of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 ("NWPA") required the federal government, through the DOE, to develop a repository for the disposal of spent nuclear fuel and high-level radioactive waste. Although the NWPA and the Company's contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel no later than January 31, 1998, the DOE has stated that it may not meet that obligation until 2020 at the earliest. This delay has required that the Company undertake additional actions and incur costs to provide on-site dry fuel storage at all three of its nuclear sites. The Company has installed additional capacity at its independent spent fuel storage installation ("ISFSI") at Calvert Cliffs, and it is constructing ISFSIs to be placed in service at Ginna in 2010 and Nine Mile Point in 2012.

In January 2004, each of the Company's plant subsidiaries filed complaints against the federal government in the U.S. Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. The cases are currently stayed, pending litigation in other related cases. Any funds received from the DOE that represent the reimbursement of costs incurred prior to the EDF

Closing shall belong to CEG, and any funds representing the reimbursement of costs incurred after the EDF Closing shall belong to CENG.

In connection with the purchases of the Nine Mile Point and Ginna plants, all of the former owners' rights and obligations related to recovery of damages for the DOE's failure to meet its contractual obligations were assigned to the Company. However, any recovery from the DOE on behalf of the Ginna damages claim is subject to a potential reimbursement back to the former owner of the facility for up to $10 million.

Nuclear Insurance

The Company maintains nuclear insurance coverage for its plants in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry-standard exclusions, including, but not limited to, ordinary wear and tear and war.

In November 2002, the President signed into law the Terrorism Risk Insurance Act ("TRIA") of 2002, which was extended by the Terrorism Risk Insurance Extension Act of 2005 and the Terrorism Risk Insurance Program Reauthorization Act of 2007. Under the TRIA, property and casualty insurance companies are required to offer insurance for losses resulting from certified acts of terrorism. Certified acts of terrorism are determined by the Secretary of the Treasury, in concurrence with the Secretary of State and Attorney General, and primarily are based upon the occurrence of significant acts of terrorism that intimidate the civilian population of the United States or attempt to influence policy or affect the conduct of the United States Government. The Company's nuclear liability, nuclear property, and accidental outage insurance programs described below provide coverage for certified acts of terrorism.

If there were a nuclear accident or an extended outage at any of the Company's units, it could have a substantial adverse effect on the Company's liquidity and financial results. In addition, if there were an accident at any nuclear power plant in the country, the Company could be assessed retrospective insurance premiums, which could have a substantial adverse effect on the Company's liquidity and financial results.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability. This limit of liability consists of the maximum available commercial insurance of $375 million and mandatory participation in an industry-wide retrospective premium assessment program. The retrospective premium assessment is $117.5 million per reactor, per incident, increasing the total amount of insurance for public liability to approximately $12.6 billion. Under the retrospective assessment program, the Company can be assessed up to $587.5 million per incident at any commercial reactor in the country, payable at no more than $87.5 million per incident per year. This assessment also applies in excess of the worker radiation claims insurance. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years based upon the Consumer Price Index and are subject to state premium taxes. In addition, the United States Congress could impose additional revenue-raising measures to pay claims.

Worker Radiation Claims Insurance

The Company participates in the American Nuclear Insurers Master Worker Program that provides coverage for worker tort claims filed for radiation injuries. The policy provides a single industry aggregate limit of $200 million for occurrences of radiation injury claims against all those insured by this policy prior to January 1, 2003; $300 million for occurrences of radiation injury claims against all those insured by this policy between January 1, 2003 and January 1, 2010; and $375 million for occurrences of radiation injury claims against all those insured by this policy on or after January 1, 2010.

The sellers of Nine Mile Point retain the liabilities for existing and potential claims that occurred prior to November 7, 2001, and the seller of Ginna retains the liabilities for existing and potential claims that occurred prior to June 10, 2004. In addition, the Long Island Power Authority, which owns 18% of Nine Mile Point Unit 2, is obligated to assume its pro rata share of any liabilities for retrospective premiums and other premium assessments. If claims under these policies exceed the coverage limits, the provisions of the Price-Anderson Act would apply.

Nuclear Property Insurance

The Company's policies provide $500 million in primary coverage at each nuclear plant. In addition, the Company maintains $1.8 billion of excess coverage at Ginna and $2.3 billion in excess coverage under a blanket excess program offered by the industry mutual insurer at both Calvert Cliffs and Nine Mile Point. Under the blanket excess policy, Calvert Cliffs and Nine Mile Point share $1.0 billion of the total $2.3 billion of excess property coverage. Therefore, in the unlikely event of two full limit property damage losses at Calvert Cliffs and Nine Mile Point, the Company would recover $4.5 billion instead of $5.5 billion.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by the Company's nuclear property insurance company within a 12-month period, they would be treated as one event and the owners of the plants where the acts occurred would share one full limit of liability ($3.2 billion as of December 31, 2009).

Accidental Nuclear Outage Insurance

The Company's policies provide indemnification on a weekly basis for losses resulting from an accidental outage of a nuclear unit. Coverage begins after a 12-week deductible period and continues at 100% of the weekly indemnity limit for 52 weeks and then 80% of the weekly indemnity limit for the next 110 weeks. The Company's coverage is up to $490 million per unit at Calvert Cliffs and Ginna, $420 million for Nine Mile Point Unit 1, and $402 million for Nine Mile Point Unit 2. These amounts can be reduced by up to $98 million per unit at Calvert Cliffs, $84 million for Nine Mile Point Unit 1, and $80 million for Nine Mile Point Unit 2 if an outage of more than one unit is caused by a single insured physical damage loss.

Both the accidental nuclear outage insurance and the nuclear property insurance are currently purchased through the industry mutual insurance company. If accidents at plants insured by the mutual insurance company result in a shortfall of funds, all policyholders could be assessed, with the Company's share being up to $93 million. During 2008, the Board of Directors for the industry mutual insurance company approved a change to CENG's policy that, in the event of a credit-rating downgrade to below-investment grade, would require the Company to post collateral in the form of a letter of credit or cash equal to $93 million. Since CENG is not rated, CEG and EDF have issued financial guarantees for the payment of the retrospective premium adjustment on behalf of the Company in the amounts of $47 million each. Alternatively, CENG would be required to purchase insurance.

February 26, 2010

VIA ELECTRONIC TRANSMISSION

Securities and Exchange Commission
Division of Corporation Finance
Attention: Filing Desk
100 F Street, N.E.
Washington, D.C. 20549

Re: File Nos. 1-12869 and 1-1910
Form 10-K for the year ended December 31, 2009

Ladies and Gentlemen:

We are transmitting to you the Form 10-K of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company for the year ended December 31, 2009 for filing under the Securities Exchange Act of 1934.

Pursuant to General Instruction D(3) of Form 10-K, we note that the financial statements included in the Form 10-K reflect a change in accounting principles relating to our method of presenting noncontrolling interests, which we adopted on January 1, 2009.

Kindly direct any notice concerning the Form 10-K or any questions or comments regarding our filing to us, Charles A. Berardesco at (410) 470-3011 or Sean J. Klein at (410) 470-5718.

Our fax number for any communication is (410) 470-2819.

Very truly yours,

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Senior Vice President and Chief Financial Officer
Constellation Energy Group, Inc.

/s/ Kevin W. Hadlock
Kevin W. Hadlock
Senior Vice President and Chief Financial Officer
Baltimore Gas and Electric Company

Enclosure