DOMINION RESOURCES INC /VA/
Form 10-Q
October 30, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2008

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 001-08489

DOMINION RESOURCES, INC.

(Exact name of registrant as specified in its charter)

VIRGINIA	**54-1229715**
(State or other jurisdiction of	***(I.R.S. Employer***
incorporation or organization)	***Identification No.)***
120 TREDEGAR STREET	
RICHMOND, VIRGINIA	**23219**
(Address of principal executive offices)	***(Zip Code)***

(804) 819-2000

(Registrant s telephone number)

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

Indicate by check mark whether the registrant 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.

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

At September 30, 2008, the latest practicable date for determination, 581,341,316 shares of common stock, without par value, of the registrant were outstanding.

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-Q are defined below:

Abbreviation or Acronym	Definition
AOCI	Accumulated other comprehensive income (loss)
BBIFNA	A subsidiary of Babcock & Brown Infrastructure Fund North America
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
CDO	Collateralized debt obligation
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Dallastown	Dallastown Realty
DCI	Dominion Capital, Inc.
DD&A	Depreciation, depletion and amortization expense
DEI	Dominion Energy, Inc.
DEPI	Dominion Exploration & Production, Inc.
DOE	Department of Energy
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion East Ohio	The East Ohio Gas Company
Dominion Retail	Dominion Retail, Inc.
Dresden	Partially-completed merchant generation facility sold in 2007
DTI	Dominion Transmission, Inc.
DVP	Dominion Virginia Power operating segment
E&P	Exploration & production
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
Equitable	Equitable Resources, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gichner	Gichner, LLC
Hope	Hope Gas, Inc.
kWh	Kilowatt-hour
LNG	Liquefied natural gas
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	Moody s Investors Services
Mw	Megawatt
mwhrs	Megawatt hours
North Anna	North Anna power station
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Ohio Commission	Public Utilities Commission of Ohio
Peaker facilities	Collectively, the three natural gas-fired merchant generation peaking facilities sold in March 2007
Pennsylvania Commission	Pennsylvania Public Utility Commission
Peoples	The Peoples Natural Gas Company
PJM	PJM Interconnection, LLC
RTO	Regional transmission organization
SEC	Securities and Exchange Commission

SFAS	Statement of Financial Accounting Standards

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Abbreviation or Acronym	Definition
State Line	State Line power station
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission
Virginia Power	Virginia Electric and Power Company
VPEM	Virginia Power Energy Marketing, Inc.
VPP	Volumetric production payment
West Virginia Commission	Public Service Commission of West Virginia

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
(millions, except per share amounts)				
Operating Revenue	**$ 4,231**	$ 3,589	**$ 12,072**	$ 11,980
Operating Expenses				
Electric fuel and energy purchases	**1,370**	914	**3,006**	2,742
Purchased electric capacity	**102**	111	**306**	339
Purchased gas	**593**	346	**2,469**	2,024
Other energy-related commodity purchases	**9**	64	**43**	184
Other operations and maintenance	**689**	1,159	**2,236**	3,906
Gain on sale of U.S. non-Appalachian E&P business	**42**	(3,617)	**42**	(3,602)
Depreciation, depletion and amortization	**259**	284	**770**	1,116
Other taxes	**112**	113	**375**	436
Total operating expenses	**3,176**	(626)	**9,247**	7,145
Income from operations	**1,055**	4,215	**2,825**	4,835
Other income	**14**	33	**10**	125
Interest and related charges:				
Interest expense	**195**	403	**566**	862
Interest expense junior subordinated notes payable[1]	**18**	30	**68**	100
Subsidiary preferred dividends	**4**	4	**12**	12
Total interest and related charges	**217**	437	**646**	974
Income from continuing operations before income taxes, minority interest and extraordinary item	**852**	3,811	**2,189**	3,986
Income tax expense	**344**	1,498	**701**	1,576
Minority interest expense (income)		(7)		7
Income from continuing operations before extraordinary item	**508**	2,320	**1,488**	2,403
Extraordinary item[2]				(158)
Loss from discontinued operations[3]		(3)	**(2)**	(5)
Net Income	**$ 508**	$ 2,317	**$ 1,486**	$ 2,240
Earnings Per Common Share - Basic				
Income from continuing operations before extraordinary item	**$ 0.88**	$ 3.65	**$ 2.58**	$ 3.55
Extraordinary item				(0.23)
Loss from discontinued operations		(0.01)		(0.01)

Net income	**$**	**0.88**	$	3.64	**$**	**2.58**	$	3.31
Earnings Per Common Share - Diluted								
Income from continuing operations before extraordinary item	**$**	**0.87**	$	3.63	**$**	**2.56**	$	3.53
Extraordinary item								(0.23)
Loss from discontinued operations				(0.01)				(0.01)
Net income	**$**	**0.87**	$	3.62	**$**	**2.56**	$	3.29
Dividends paid per common share	**$**	**0.395**	$	0.355	**$**	**1.185**	$	1.065

(1) Includes affiliated interest expense of $5 million and $17 million for the three months ended September 30, 2008 and 2007, respectively, and $28 million and $61 million for the nine months ended September 30, 2008 and 2007, respectively.

(2) Reflects a $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to the Virginia jurisdiction of our generation operations.

(3) Net of income tax benefit of $3 million for the nine months ended September 30, 2008. Includes income tax expense of $3 million and $116 million for the three and nine months ended September 30, 2007, respectively. For the nine months ended September 30, 2007, the expense includes $76 million and $56 million for U.S. federal and Canadian taxes, respectively, related to the gain on the sale of our Canadian E&P operations.

The accompanying notes are an integral part of our Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2008	December 31, 2007[1]
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 88**	$ 283
Customer receivables (less allowance for doubtful accounts of $29 and $37)	**2,085**	2,130
Other receivables (less allowance for doubtful accounts of $7 and $10)	**149**	226
Inventories	**1,231**	1,045
Derivative assets	**1,301**	775
Assets held for sale	**1,388**	1,160
Other	**1,091**	1,051
Total current assets	**7,333**	6,670
Investments		
Nuclear decommissioning trust funds	**2,539**	2,888
Other	**943**	992
Total investments	**3,482**	3,880
Property, Plant and Equipment		
Property, plant and equipment	**34,744**	33,331
Accumulated depreciation, depletion and amortization	**(12,148)**	(11,979)
Total property, plant and equipment, net	**22,596**	21,352
Deferred Charges and Other Assets		
Goodwill	**3,503**	3,496
Pension and other postretirement benefit assets	**1,514**	1,565
Regulatory assets	**1,578**	957
Other	**1,373**	1,219
Total deferred charges and other assets	**7,968**	7,237
Total assets	**$ 41,379**	$ 39,139

(1) Our Consolidated Balance Sheet at December 31, 2007 has been derived from the audited Consolidated Financial Statements at that date and includes the impact of adopting FSP FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts*, as discussed in Note 3.

The accompanying notes are an integral part of our Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(millions)	September 30, 2008	December 31, 2007[1]
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 754**	$ 1,477
Short-term debt	**2,451**	1,757
Accounts payable	**1,507**	1,734
Accrued interest, payroll and taxes	**702**	934
Derivative liabilities	**1,275**	694
Liabilities held for sale	**617**	492
Other	**665**	672
Total current liabilities	**7,971**	7,760
Long-Term Debt		
Long-term debt	**13,051**	11,759
Junior subordinated notes payable:		
Affiliates	**268**	678
Other	**798**	798
Total long-term debt	**14,117**	13,235
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,490**	4,253
Asset retirement obligations	**1,783**	1,722
Regulatory liabilities	**1,106**	1,223
Other	**1,190**	1,255
Total deferred credits and other liabilities	**8,569**	8,453
Total liabilities	**30,657**	29,448
Commitments and Contingencies (see Note 17)		
Minority Interest		28
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock - no par[2]	**5,922**	5,733
Other paid-in capital	**187**	175
Retained earnings	**4,307**	3,510
Accumulated other comprehensive income (loss)	**49**	(12)
Total common shareholders equity	**10,465**	9,406

Total liabilities and shareholders equity	**$**	**41,379**	$	39,139

(1) Our Consolidated Balance Sheet at December 31, 2007 has been derived from the audited Consolidated Financial Statements at that date and includes the impact of adopting FSP FIN 39-1, as discussed in Note 3.

(2) 1 billion shares authorized; 581 million shares outstanding at September 30, 2008 and 577 million shares outstanding at December 31, 2007.

The accompanying notes are an integral part of our Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

Nine Months Ended September 30,	**2008**	**2007**
(millions)		
Operating Activities		
Net income	**$ 1,486**	$ 2,240
Adjustments to reconcile net income to net cash provided by operating activities:		
Dominion Capital, Inc. (DCI) impairment losses	**62**	86
Dresden impairment loss		387
Costs associated with early retirement of debt		242
Gain on sale of non-Appalachian E&P business	**42**	(3,796)
Extraordinary item, net of income taxes		158
Charges related to termination of volumetric production payment (VPP) agreements		139
Net realized and unrealized derivative losses	**177**	373
Depreciation, depletion and amortization	**888**	1,244
Deferred income taxes and investment tax credits, net	**351**	(1,670)
Changes in:		
Accounts receivable	**187**	766
Inventories	**(244)**	(15)
Prepayments	**(22)**	129
Deferred fuel and purchased gas costs, net	**(636)**	(164)
Accounts payable	**(289)**	(631)
Accrued interest, payroll and taxes	**(232)**	2,880
Margin deposit assets and liabilities	**(249)**	(79)
Other operating assets and liabilities	**(106)**	(6)
Net cash provided by operating activities	**1,415**	2,283
Investing Activities		
Plant construction and other property additions	**(2,307)**	(1,449)
Additions to gas and oil properties, including acquisitions	**(166)**	(1,788)
Proceeds from assignment of natural gas drilling rights	**343**	
Proceeds from sale of merchant generation peaking facilities		339
Proceeds from sale of non-Appalachian E&P business	**(21)**	13,706
Proceeds from sales of securities and loan receivable collections and payoffs	**1,058**	968
Purchases of securities and loan receivable originations	**(1,035)**	(1,030)
Investments in affiliates	**(337)**	(70)
Other	**144**	138
Net cash provided by (used in) investing activities	**(2,321)**	10,814
Financing Activities		
Issuance (repayment) of short-term debt, net	**695**	(2,332)
Issuance of long-term debt	**1,830**	1,235
Repayment of long-term debt, including redemption premiums	**(889)**	(4,984)
Repayment of affiliated notes payable	**(412)**	(440)
Issuance of common stock	**178**	193
Repurchase of common stock		(5,763)
Common dividend payments	**(686)**	(704)
Other	**(7)**	27

Net cash provided by (used in) financing activities	**709**	(12,768)
Increase (decrease) in cash and cash equivalents	**(197)**	329
Cash and cash equivalents at beginning of period[1]	**287**	142
Cash and cash equivalents at end of period[2]	**$ 90**	$ 471
Significant Noncash Investing and Financing Activities:		
Accrued capital expenditures	**$ 60**	$ 56
Proceeds held in escrow from sale of Canadian E&P operations		156

(1) 2008 and 2007 amounts include $4 million of cash classified as held for sale in our Consolidated Balance Sheets.
(2) 2008 and 2007 amounts include $2 million of cash classified as held for sale in our Consolidated Balance Sheets.
The accompanying notes are an integral part of our Consolidated Financial Statements.

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DOMINION RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Nature of Operations

Dominion Resources, Inc., headquartered in Richmond, Virginia, is one of the nation s largest producers and transporters of energy. Our principal subsidiaries are Virginia Power, Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI), Virginia Power Energy Marketing, Inc. (VPEM), Dominion Exploration & Production, Inc. (DEPI), Dominion East Ohio and Dominion Retail, Inc. (Dominion Retail).

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of September 30, 2008, Virginia Power served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. Virginia Power is a member of PJM, a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

DEI engages in merchant generation, energy marketing and price risk management activities and natural gas exploration and production in the Appalachian basin of the U.S.

DTI operates a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states and is engaged in the production, gathering and extraction of natural gas in the Appalachian basin.

VPEM provides fuel, gas supply management, and price risk management services to other Dominion affiliates and engages in energy trading and marketing activities.

DEPI explores for, develops and produces natural gas liquids and oil in the Appalachian basin.

Dominion Retail markets gas, electricity and related products and services to residential and small commercial customers. As of September 30, 2008, our nonregulated retail energy marketing operations served approximately 1.7 million residential and small commercial customer accounts in the Northeast, mid-Atlantic and Midwest regions of the U.S and Texas.

As of September 30, 2008, our regulated gas distribution subsidiaries, Dominion East Ohio, Peoples and Hope, served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia. Approximately 500,000 of these customers are served by Peoples and Hope, which are classified as held for sale, as discussed in Note 5. We also operate a liquefied natural gas (LNG) import and storage facility in Maryland. Our producer services operations involve the aggregation of natural gas supply and related marketing activities.

We manage our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Energy and Dominion Generation. In addition, we also report a Corporate and Other segment that includes our service company functions, as well as the net impact of certain operations disposed of or to be disposed of, as discussed in Note 5. Our assets remain wholly owned by us and our legal subsidiaries.

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any the following: the legal entity, Dominion Resources, Inc., one or more of Dominion Resources, Inc. s consolidated subsidiaries or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the SEC, our accompanying unaudited Consolidated Financial Statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with GAAP. These unaudited Consolidated Financial Statements should be read in conjunction with our Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments, including normal recurring accruals, necessary to present fairly our financial position as of September 30, 2008, our results of operations for the three and nine months ended September 30, 2008 and 2007 and our cash flows for the nine months ended September 30, 2008 and 2007.

We make certain estimates and assumptions in preparing our Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions 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 for the periods presented. Actual results may differ from those estimates.

Our accompanying unaudited Consolidated Financial Statements include, after eliminating intercompany transactions and balances, our accounts and those of our majority-owned subsidiaries.

In accordance with GAAP, we report certain contracts and instruments at fair value. See Note 11 for further information on fair value measurements in accordance with SFAS No. 157, *Fair Value Measurements*.

The results of operations for interim periods are not necessarily indicative of the results expected for the full year. Information for quarterly periods is affected by seasonal variations in sales, rate changes, electric fuel and energy purchases, purchased gas expenses and other factors.

Certain amounts in our 2007 Consolidated Financial Statements and Notes have been recast to conform to the 2008 presentation. See Note 3 for discussion of certain 2007 amounts that have been recast due to the adoption of FSP FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts*.

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007 resulted in a $259 million ($158 million after-tax) extraordinary charge and the reclassification of $195 million ($119 million after-tax) of unrealized gains from AOCI, related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*.

Note 3. Newly Adopted Accounting Standards

SFAS No. 157

We adopted the provisions of SFAS No. 157, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and non-financial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances.

Generally, the provisions of this statement are applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments* . Retrospective application resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

In February 2008, the FASB issued FSP FAS No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*, which excludes leasing transactions from the scope of SFAS No. 157. However, the exclusion does not apply to fair value measurements of assets and liabilities recorded as a result of a lease transaction but measured pursuant to other pronouncements within the scope of SFAS No. 157.

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In February 2008, the FASB issued FSP FAS No. 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This delays the effective date of SFAS No. 157 primarily for goodwill, intangibles, property, plant and equipment and asset retirement obligations.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,* which clarifies the application of SFAS No. 157 to financial assets in a market that is not active. This FSP was effective for the third quarter of 2008 and confirms that SFAS No. 157 allows for the use of unobservable inputs in determining the fair value of a financial asset when relevant observable inputs do not exist or when observable inputs require significant adjustment based on unobservable data. This may be the case, for example, in an inactive or distressed market. This FSP did not have an impact on our results of operations or financial condition.

See Note 11 for further information on fair value measurements in accordance with SFAS No. 157.

SFAS No. 159

The provisions of SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, became effective for us beginning January 1, 2008. SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. As of September 30, 2008, we had not elected the fair value option for any eligible items. Therefore, the provisions of SFAS No. 159 have not impacted our results of operations or financial condition.

FSP FIN 39-1

The provisions of FSP FIN 39-1 became effective for us beginning January 1, 2008. FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement that have been offset. Upon our adoption of FSP FIN 39-1, we revised our accounting policy to no longer offset fair value amounts recognized for certain derivative instruments and recast our prior year Consolidated Balance Sheet in order to retrospectively apply the standard. The adoption of FSP FIN 39-1 resulted in an increase in Derivative assets of $14 million, Other deferred charges and other assets of $2 million, Derivative liabilities of $14 million and Other deferred credits and other liabilities of $2 million as of December 31, 2007. The adoption of FSP FIN 39-1 had no impact on our results of operations or cash flows.

EITF 06-4

The provisions of EITF Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements*, became effective for us beginning January 1, 2008. EITF 06-4 specifies that if an employer provides a benefit to an employee under an endorsement split-dollar life insurance arrangement that extends to postretirement periods, it should recognize a liability for future benefits in accordance with SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions* (if, in substance, a postretirement benefit plan exists) or APB Opinion No. 12, *Deferred Compensation Contracts* (if the arrangement is, in substance, an individual deferred compensation contract) based on the substantive agreement with the employee. The adoption of EITF 06-4 resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

EITF 06-11

The provisions of EITF Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*, became effective for us beginning January 1, 2008. EITF 06-11 addresses the recognition of income tax benefits realized from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for nonvested share-based payment awards that are classified as equity. Effective January 1, 2008, we began recognizing such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. Our adoption of EITF 06-11 did not have a material impact on our results of operations or financial condition.

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Note 4. Recently Issued Accounting Standards

SFAS No. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*. SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, *Accounting for Income Taxes*, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, *Accounting for Uncertainty in Income Taxes*, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties and acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. For acquisitions completed on or before September 30, 2008, we do not expect these SFAS No. 141R provisions to have a material impact on our future results of operations or financial condition.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements.* SFAS No. 160 requires that noncontrolling (minority) interests be reported as a component of equity, net income attributable to the parent and to the non-controlling interest be separately identified in the income statement, changes in a parent s ownership interest while the parent retains its controlling interest be accounted for as equity transactions, and any retained noncontrolling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. The provisions of SFAS No. 160 will become effective for us beginning January 1, 2009. We do not expect the provisions of SFAS No. 160 to have an impact on our results of operations or financial condition.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 requires enhancements to disclosures regarding derivative instruments and hedging activities accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The enhancements include additional disclosures regarding the reasons derivative instruments are used, how they are used, how these instruments and their related hedged items are accounted for under SFAS No. 133, as well as the impact of these derivative instruments on an entity s results of operations, financial condition and cash flows. In addition, SFAS No. 161 requires the disclosure of the fair values of derivative instruments and associated gains and losses in a tabular format and information about derivative features that are credit-risk related. The provisions of SFAS No. 161 will become effective for us beginning January 1, 2009, and will have no impact on our results of operations or financial condition.

FSP EITF 03-6-1

In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. This FSP addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method as described in SFAS No. 128, *Earnings per Share*. Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. The provisions of FSP EITF 03-6-1 will become effective for us beginning January 1, 2009 and are to be applied retrospectively. We do not expect FSP EITF 03-6-1 to have a material impact on our earnings per share.

FSP APB 14-1

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of Accounting Principles Board Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* The FSP specifies that issuers of convertible debt instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The provisions of FSP APB 14-1 will become effective for us beginning January 1, 2009 and will be applied retrospectively.

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We have determined that the provisions of FSP APB 14-1 will be applicable to $220 million of our 2.125% unsecured convertible senior notes due in 2023. We do not expect the adoption of FSP APB 14-1 to have a material impact on our results of operations or financial position and its adoption will have no impact on our consolidated cash flows.

EITF 07-5

In June 2008, the FASB ratified the consensus on EITF 07-5, *Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock*. This issue addresses whether an instrument (or an embedded feature) is indexed to an entity s own stock, which is the first part of the scope exception in paragraph 11(a) of SFAS No. 133, for purposes of determining whether the instrument should be classified as an equity instrument or accounted for as a derivative instrument. The provisions of EITF 07-5 will become effective for us beginning January 1, 2009 and will be applied retrospectively through a cumulative effect adjustment to retained earnings should we have outstanding instruments within its scope as of that date. We do not expect EITF 07-5 to have a material impact on our results of operations or financial condition.

Note 5. Dispositions

Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

In 2007, we completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. The results of operations for our U.S. non-Appalachian E&P operations were not reported as discontinued operations in our Consolidated Statements of Income since we did not sell our entire U.S. cost pool, which includes the retained Appalachian assets. Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P operations are reported as discontinued operations in our 2007 Consolidated Statement of Income. For the nine months ended September 30, 2007, our Canadian E&P operations reported $82 million of operating revenue and $149 million of income before income taxes, including a pre-tax gain of $194 million recognized on the sale.

Costs Associated with Disposal of Non-Appalachian E&P Operations

The sale of our U.S. non-Appalachian E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we recognized charges, recorded in other operations and maintenance expense in our Consolidated Statement of Income, predominantly reflecting the reclassification of losses from AOCI to earnings and subsequent changes in fair value of these contracts of $544 million ($347 million after-tax) for the nine months ended September 30, 2007. We recognized a similar charge of $15 million ($9 million after-tax) for the nine months ended September 30, 2007 related to our Canadian operations, which is reflected in discontinued operations in our Consolidated Statement of Income.

During the nine months ended September 30, 2007, we also recorded a charge of approximately $171 million ($108 million after-tax) for the recognition of certain forward gas contracts that previously qualified for the normal purchase and sales exemption under SFAS No. 133. The $171 million charge includes $139 million associated with VPP agreements to which we were a party. We paid $250 million to terminate the VPP agreements and retained the repurchased fixed-term overriding royalty interests formerly associated with these agreements.

Additionally, we recognized expenses for employee severance, retention and other costs of $77 million ($48 million after-tax) for the nine months ended September 30, 2007, related to the sale of our U.S. non-Appalachian E&P business, which are reflected in other operations and maintenance expense in our Consolidated Statement of Income. We also recognized expenses for employee severance, retention, legal, investment banking and other costs of $30 million ($18 million after-tax) for the nine months ended September 30, 2007 related to the sale of our Canadian E&P operations, which are reflected in discontinued operations in our Consolidated Statement of Income.

In 2007, we recognized a gain of approximately $3.6 billion ($2.1 billion after-tax) from the disposition of our U.S. non-Appalachian E&P operations. This gain was net of expenses related to the disposition plan for transaction costs, including audit, legal, investment banking and other costs of $47 million ($29 million after-tax), but excludes severance and retention costs and costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts. In 2008, post-closing adjustments resulted in a $42 million ($26 million after-tax) reduction to the gain recognized in 2007.

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For the nine months ended September 2007, we recognized charges of $242 million ($148 million after-tax) associated with the completion of a debt tender offer using a portion of the proceeds from the sale. Of this amount, $234 million ($143 million after-tax) was recorded in interest and related charges in our Consolidated Statements of Income.

The total impact on net income from the sale of our Canadian and U.S. non-Appalachian E&P operations for the three and nine months ended September 30, 2007, was a benefit of $1.9 billion and $1.5 billion, respectively. This benefit was net of expenses for transaction costs, severance and retention costs, costs associated with the discontinuance of hedge accounting and recognition of forward gas contracts, and costs associated with our debt tender offer completed in July 2007 using a portion of the proceeds received from the sale.

Disposition of Partially Completed Generation Facility

In September 2007, we completed the sale of the partially-completed Dresden Energy merchant generation facility (Dresden) to AEP Generating Company (AEP) for $85 million. During the second quarter 2007, we recorded a $387 million ($252 million after-tax) impairment charge in other operations and maintenance expense to reduce Dresden s carrying amount to its estimated fair value based on AEP s purchase price.

Sale of Merchant Generation Facilities

In March 2007, we sold the Peaker facilities for net cash proceeds of $254 million. The results of operations of the Peaker facilities are reported as discontinued operations in our 2007 Consolidated Statement of Income. For the nine months ended September 30, 2007, the Peaker facilities recorded $5 million of operating revenue and a $31 million loss before income taxes. The loss before income taxes included a pre-tax loss of $25 million recognized on the sale.

Sale of Certain DCI Operations

In August 2007, we completed the sale of Gichner, LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner) and Dallastown Realty (Dallastown) for approximately $30 million. The results of operations of Gichner and Dallastown are reported as discontinued operations in our Consolidated Statements of Income. For the three and nine months ended September 30, 2007, Gichner and Dallastown recorded $7 million and $29 million of operating revenue and $1 million and $7 million of losses before income taxes, respectively. The sale resulted in an after-tax loss of $4 million.

In April 2008, we sold our remaining interest in the subordinated notes of a third-party collateralized debt obligation (CDO) entity held as an investment by DCI and received proceeds of $54 million, including accrued interest. In connection with the sale of the subordinated notes, we recognized impairment losses of $62 million ($38 million after-tax) for the nine months ended September 30, 2008. As discussed in Note 14, we deconsolidated the CDO entity as of March 31, 2008.

Planned Sale of Regulated Gas Distribution Subsidiaries

In March 2006, we entered into an agreement with Equitable for the sale of Peoples and Hope. In January 2008, Dominion and Equitable announced the termination of that agreement, primarily due to the continued delays in achieving final regulatory approvals. We continued to seek other offers for the purchase of these utilities.

In July 2008, we announced that we entered into an agreement with a subsidiary of Babcock & Brown Infrastructure Fund North America (BBIFNA) to sell Peoples and Hope for approximately $910 million, subject to adjustments to reflect levels of capital expenditures and changes in working capital. The transaction is expected to close in 2009, subject to regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act.

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The carrying amounts of the major classes of assets and liabilities associated with the planned sale of Peoples and Hope and classified as held for sale in our Consolidated Balance Sheets are as follows:

	September 30, 2008	December 31, 2007
(millions)		
ASSETS		
Current Assets		
Customer receivables	**$ 80**	$ 147
Other	**221**	109
Total current assets	**301**	256
Property, Plant and Equipment		
Property, plant and equipment	**1,188**	1,160
Accumulated depreciation, depletion and amortization	**(360)**	(367)
Total property, plant and equipment, net	**828**	793
Deferred Charges and Other Assets		
Regulatory assets	**159**	109
Other	**100**	2
Total deferred charges and other assets	**259**	111
Assets held for sale	**$ 1,388**	$ 1,160
LIABILITIES		
Current Liabilities	**$ 196**	$ 210
Deferred Credits and Other Liabilities		
Deferred income taxes[1]	**322**	203
Other	**99**	79
Total deferred credits and other liabilities	**421**	282
Liabilities held for sale	**$ 617**	$ 492

(1) Represents net deferred tax liabilities that relate to, and are being reported with, the subsidiaries assets and liabilities held for sale and that, based on the form of the dispositions, will reverse upon closing.

The following table presents selected information regarding the results of operations of Peoples and Hope:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
(millions)				
Operating revenue	**$ 74**	$ 62	**$ 480**	$ 479
Income (loss) before income taxes[1]		(6)	**100**	49

(1) Income before income taxes for the nine months ended September 30, 2008 includes a $47 million benefit related to the re-establishment of a regulatory asset in connection with the pending sale of Peoples and Hope to BBIFNA.

Note 6. Operating Revenue

Our operating revenue consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
(millions)				
Operating Revenue				
Electric sales:				
Regulated	**$ 2,143**	$ 1,796	**$ 5,153**	$ 4,593
Nonregulated	**1,010**	839	**2,657**	2,299
Gas sales:				
Regulated	**107**	86	**898**	829
Nonregulated	**676**	471	**2,207**	2,584
Other energy-related commodity sales	**58**	142	**213**	722
Gas transportation and storage	**189**	181	**799**	742
Other	**48**	74	**145**	211
Total operating revenue	**$ 4,231**	$ 3,589	**$ 12,072**	$ 11,980

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Note 7. Income Taxes

A reconciliation of income taxes at the U.S. statutory federal rate as compared to the income tax expense recorded for continuing operations in our Consolidated Statements of Income is presented below:

	Nine Months Ended September 30,	
	2008	**2007**
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
State taxes, net of federal benefit	**3.9**	3.4
Reversal of deferred taxes stock of subsidiaries held for sale	**(6.2)**	(0.2)
Changes in valuation allowances	**0.7**	(2.6)
Goodwill		5.2
Other, net	**(1.3)**	(1.3)
Effective tax rate	**32.1%**	39.5%

The change in our effective tax rate for the nine months ended September 30, 2008, is primarily attributable to the reversal of deferred tax liabilities, recognized in 2006, associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope, in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company s Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation.* Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent s investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. In 2006, based on the intended form of the sale to Equitable, we recognized these deferred tax liabilities as such difference was expected to reverse upon closing of the sale.

In January 2008, Dominion and Equitable agreed to terminate the agreement for the sale of Peoples and Hope. At that time, based on our expectation that the form of the ultimate disposal of these subsidiaries could be structured so that the taxable gain would instead be determined by reference to the basis in the subsidiaries underlying assets, we reversed those deferred tax liabilities recognized in 2006. As discussed in Note 5, we have executed a new agreement to sell Peoples and Hope. We will determine our taxable gain by reference to the basis in the subsidiaries underlying assets.

As the result of West Virginia income tax rate reductions enacted in March 2008, to be phased in during the period 2009 through 2014, we reduced our net deferred tax liabilities by $12 million. In addition, we recognized $11 million of additional deferred tax expense to reflect Massachusetts legislation enacted in July 2008 that requires combined reporting and provides for tax rate reductions during the period 2010 through 2012.

Our 2007 effective tax rate reflects the effects of the sale of the majority of our U.S. E&P operations. The effects included the impact of goodwill, not recognized for tax purposes, that was deducted in the determination of book gain on the sale and the recognition of additional deferred tax expense to reflect changes in our state income tax profile. Those effects were partially offset by tax benefits related to the elimination of valuation allowances on federal loss carryforwards that would be utilized to offset gains generated from the sale.

At September 30, 2008, unrecognized tax benefits related to current year tax positions were $43 million. During the nine months ended September 30, 2008, unrecognized tax benefits related to prior year uncertain tax positions increased by $40 million and decreased by $67 million, reflecting reductions to uncertain tax positions for amounts that would otherwise be deductible in 2008, settlement negotiations and payments to tax authorities.

We are currently engaged in settlement negotiations with tax authorities regarding certain adjustments proposed during the examination of tax years 2002, 2003 and 2004. We believe that it is reasonably possible, based on settlement negotiations and risks of litigation, that unrecognized tax benefits could decrease by up to $95 million over the next twelve months with no material impact on our results of operations.

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Note 8. Earnings Per Share

The following table presents the calculation of our basic and diluted EPS:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
(millions, except EPS)				
Income from continuing operations before extraordinary item	**$ 508**	$ 2,320	**$ 1,488**	$ 2,403
Extraordinary item, net of tax				(158)
Loss from discontinued operations, net of tax		(3)	**(2)**	(5)
Net income	**$ 508**	$ 2,317	**$ 1,486**	$ 2,240
Basic EPS				
Average shares of common stock outstanding basic	**578.6**	635.6	**577.0**	676.7
Income from continuing operations before extraordinary item	**$ 0.88**	$ 3.65	**$ 2.58**	$ 3.55
Extraordinary item				(0.23)
Loss from discontinued operations		(0.01)		(0.01)
Net income	**$ 0.88**	$ 3.64	**$ 2.58**	$ 3.31
Diluted EPS				
Average shares of common stock outstanding	**578.6**	635.6	**577.0**	676.7
Net effect of potentially dilutive securities(1)	**3.4**	4.0	**3.3**	4.5
Average shares of common stock outstanding diluted	**582.0**	639.6	**580.3**	681.2
Income from continuing operations before extraordinary item	**$ 0.87**	$ 3.63	**$ 2.56**	$ 3.53
Extraordinary item				(0.23)
Loss from discontinued operations		(0.01)		(0.01)
Net income	**$ 0.87**	$ 3.62	**$ 2.56**	$ 3.29

(1) Potentially dilutive securities consist of stock options, restricted stock and contingently convertible senior notes.
There were no anti-dilutive securities outstanding during the three or nine months ended September 30, 2008 or 2007.

Note 9. Property, Plant and Equipment

Marcellus Shale

We previously entered into an agreement with Antero Resources (Antero) to assign natural gas drilling rights on approximately 205,000 Appalachian Basin net acres for approximately $552 million; however, due to Antero s difficulty in obtaining follow-on financing, the amount assigned was reduced. On September 30, 2008, we completed a transaction with Antero to assign drilling rights to approximately 114,000 acres in the Marcellus Shale formation located in West Virginia and Pennsylvania. We received approximately $347 million and recognized $4 million of associated closing costs. Under the agreement, we will receive a 7.5% overriding royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage. The transaction is subject to post-closing title adjustments; however, any such adjustments would be settled through acreage substitution.

We follow the full cost method of accounting for gas and oil E&P activities as prescribed by the SEC. Under the full cost method of accounting, gains or losses on the sale or other disposition of gas and oil properties are not recognized, unless the gain or loss would significantly alter the relationship between the capitalized costs and proved reserves of natural gas and oil. We initially expected to recognize a pre-tax gain based on the terms of the initial agreement with Antero, however, due to the reduced size of the final transaction no material alteration occurred and the net proceeds were credited to the full cost pool, reducing property, plant and equipment in our Consolidated Balance Sheet. After-tax proceeds of $205 million will be used initially to reduce outstanding short-term debt.

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Note 10. Comprehensive Income

The following table presents total comprehensive income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
(millions)				
Net income	**$ 508**	$ 2,317	**$ 1,486**	$ 2,240
Other comprehensive income (loss):				
Net other comprehensive income associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**1,263**(1)	104	**140**(1)	428(2)
Other, net of tax	**(19)**(3)	18(4)	**(79)**(3)	(52)(5)
Other comprehensive income	**1,244**	122	**61**	376
Total comprehensive income	**$ 1,752**	$ 2,439	**$ 1,547**	$ 2,616

(1) For the quarter, principally due to the impact of a decrease in commodity prices. For the year-to-date period, reflects a decrease in commodity prices in the third quarter, partially offset by an increase in commodity prices through the first six months of the year.

(2) Principally due to the de-designation of certain E&P cash flow hedges in connection with the sale of our non-Appalachian E&P operations.

(3) Primarily represents a reduction in unrealized gains on investments held in merchant nuclear decommissioning trusts.

(4) Primarily reflects the recognition of certain pension-related amounts as a component of net periodic benefit cost that were previously deferred in AOCI.

(5) Primarily reflects the impact of foreign currency translation adjustments due to the sale of our Canadian E&P operations and the reclassification of pension-related amounts and gross unrealized gains on investments held in nuclear decommissioning trusts, both associated with the Virginia jurisdiction of our utility generation operations. As a result of the reapplication of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to those operations, those amounts previously recorded in AOCI are now recorded in regulatory assets and regulatory liabilities.

Note 11. Fair Value Measurements

As described in Note 3, we adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, SFAS No. 157 permits the use of a mid-market pricing convention (the mid-point between bid and ask prices). SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. SFAS No. 157 also requires fair value measurements to assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). We apply fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments, and nuclear decommissioning trust and other investments in accordance with the requirements described above. We apply credit adjustments to our derivative fair values in accordance with the requirements described above. These credit adjustments are not material to the derivative fair values.

In accordance with SFAS No. 157, we maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, we seek price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, or if we believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect our market assumptions.

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For options and contracts with option-like characteristics where observable pricing information is not available from external sources, we generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. We use other option models under special circumstances, including a Spread Approximation Model, when contracts include different commodities or commodity locations and a Swing Option Model, when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, we may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different valuation models or assumptions could have a material effect on the contract s estimated fair value.

We also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as the majority of exchange-traded derivatives, listed equities and Treasury securities.

Level 2 Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps, interest rate swaps, foreign currency forwards and options and municipal bonds held in nuclear decommissioning and rabbi trust funds.

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, natural gas liquids contracts (NGLs), natural gas peaking options, financial transmission rights (FTRs) and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

Fair value measurements are categorized as Level 3 when a significant amount of price and other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to the length of time to settlement and are therefore categorized as Level 3. For NGLs, market illiquidity requires a valuation based on proxy markets that do not always correlate to the actual instrument, therefore they are also categorized as Level 3. For the same illiquidity reason, natural gas peaking options at non-Henry Hub locations are valued using Henry Hub volatilities, which may or may not be identical to the volatilities at transacted locations, and are therefore considered to be unobservable inputs. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from independent system operator auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of September 30, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a liability of $102 million. A hypothetical 10% increase in commodity prices would increase the liability by $95 million, while a hypothetical 10% decrease in commodity prices would decrease the liability by $97 million.

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SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions as of September 30, 2008:

(millions)	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives	$ 57	$ 1,366	$ 116	$ 1,539
Investments	897	1,624		2,521
Total assets	954	2,990	116	4,060
Liabilities:				
Derivatives	$ 24	$ 1,202	$ 218	$ 1,444

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the three and nine months ended September 30, 2008:

(millions)	Derivatives[1]
Three Months Ended September 30, 2008	
Balance at July 1, 2008	$ (191)
Total realized and unrealized gains or (losses):	
Included in earnings	(9)
Included in other comprehensive income (loss)	357
Included in regulatory and other assets/liabilities	(249)
Purchases, issuances and settlements	(15)
Transfers out of Level 3	5
Balance at September 30, 2008	$ (102)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	$ (35)
Nine Months Ended September 30, 2008	
Balance at January 1, 2008	$ (61)
Total realized and unrealized gains or (losses):	
Included in earnings	53
Included in other comprehensive income (loss)	(19)
Included in regulatory and other assets/liabilities	(49)
Purchases, issuances and settlements	(27)
Transfers out of Level 3	1
Balance at September 30, 2008	$ (102)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	$ (3)

(1) Derivative assets and liabilities are presented on a net basis.

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The following table presents gains and losses included in earnings in the Level 3 fair value category for the three and nine months ended September 30, 2008:

(millions)	Operating Revenue	Electric Fuel and Energy Purchases	Other Operations and Maintenance	Total
Three Months Ended September 30, 2008				
Total gains or (losses) included in earnings	$	$ 13	$ (22)	$ (9)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	(4)		(31)	(35)
Nine Months Ended September 30, 2008				
Total gains or (losses) included in earnings	$ (40)	$ 54	$ 39	$ 53
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date			(3)	(3)

Note 12. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products marketed and purchased, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133. As discussed in Note 2 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, for certain jurisdictions subject to cost-based regulation, changes in the fair value of derivatives designated as hedges are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. Selected information about our hedge accounting activities follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	**2008**	2007
(millions)				
Portion of gains on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	**$ 9**	$ 3	**$ 3**	$ 5
Cash flow hedges		4	**1**	47
Net ineffectiveness	**$ 9**	$ 7	**$ 4**	$ 52

For the three and nine months ended September 30, 2008 and 2007, amounts excluded from the measurement of effectiveness did not have a significant impact on net income.

See Note 5 for a discussion of the discontinuance of hedge accounting for gas and oil hedges in 2007.

In the third quarter of 2007, as a result of the expected termination of the long-term power sales agreement associated with our 515 Mw State Line power station (State Line), we discontinued applying the normal purchase and normal sale exemption allowed under SFAS No. 133 to this agreement and recorded a $236 million ($140 million after-tax) charge in other operations and maintenance expense in our Consolidated Statement of Income. During the fourth quarter of 2007, we paid approximately $229 million primarily in exchange for the termination of the power sales agreement, acquisition of coal inventory and assignment of certain coal supply, transportation and railcar lease contracts.

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The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at September 30, 2008:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
Gas	$ 36	$ 31	39 months
Electricity	76	44	39 months
Natural gas liquids	(31)	(10)	39 months
Other	8	4	80 months
Interest rate	7	(2)	363 months
Foreign currency	2	1	48 months
Total	$ 98	$ 68	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign exchange rates.

Note 13. Ceiling Test

We follow the full cost method of accounting for gas and oil E&P activities prescribed by the SEC. Under the full cost method, capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, discounted at 10%, assuming period-end hedge-adjusted prices.

Approximately 5% of our anticipated production, from our remaining E&P operations and fixed-term overriding royalty interests formerly associated with VPP agreements terminated in conjunction with the 2007 sale of the majority of our U.S. E&P operations, is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of September 30, 2008.

Note 14. Variable Interest Entities

As discussed in Note 17 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered variable interests in the counterparties in accordance with FIN 46 (revised December 2003), *Consolidation of Variable Interest Entities*.

We have long-term power and capacity contracts with four variable interest entities (VIEs), which contain certain variable pricing mechanisms to the counterparty in the form of partial fuel reimbursement. We have concluded that we are not the primary beneficiary of any of these VIEs. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these VIEs other than our remaining purchase commitments which totaled $2 billion as of September 30, 2008. We paid $50 million and $51 million for electric capacity and $60 million and $50 million for electric energy to these entities for the three months ended September 30, 2008 and 2007, respectively. We paid $152 million and $160 million for electric capacity and $153 million and $128 million for electric energy to these entities for the nine months ended September 30, 2008 and 2007, respectively.

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As discussed in Note 28 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, DCI held an investment in the subordinated notes of a third-party CDO entity. The CDO entity s primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets. We concluded previously that the CDO entity was a VIE and that DCI was the primary beneficiary of the CDO entity and therefore we consolidated the CDO entity in accordance with FIN 46R at December 31, 2007. Due to the consolidation of the CDO entity at December 31, 2007, our consolidated balance sheet included $460 million of notes payable, which were nonrecourse to us, and the following assets that served as collateral for its obligations:

	Amount
(millions)	
Other current assets[(1)]	$ 257
Loans held for sale	323
Other investments	32
Total assets	$ 612

(1) Includes $30 million of loans held for resale.

In March 2008, we entered into an agreement to sell our remaining interest in the subordinated notes effectively eliminating the variability of our interest, and therefore deconsolidated the CDO entity as of March 31, 2008.

Note 15. Significant Financing Transactions

Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The levels of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and our credit quality and the credit quality of our counterparties. At September 30, 2008, we had committed lines of credit totaling $5.4 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At September 30, 2008, we had the following commercial paper, bank loans and letters of credit outstanding and capacity available under our credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Borrowings	Outstanding Letters of Credit	Facility Capacity Available
(millions)					
Five-year joint revolving credit facility[(1)]	$ 3,000	$ 664	$	$ 239	$ 2,097
Five-year Dominion credit facility[(2)]	1,700	1,041	600	59	
Five-year Dominion bilateral facility[(3)]	200	146			54
364-day Dominion credit facility[(4)]	500				500
Totals	$ 5,400	$ 1,851	$ 600	$ 298	$ 2,651

(1) The $3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.

(2)

The amended and restated $1.7 billion five-year credit facility is dated February 2006 and terminates in August 2010. This facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

(3) The $200 million five-year facility was entered into in December 2005 and terminates in December 2010. This bilateral credit facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

(4) The $500 million 364-day credit facility was entered into in July 2008 and terminates in July 2009. This credit facility can be used to support bank borrowings and the issuance of commercial paper.

In addition to the credit facility commitments of $5.4 billion disclosed above, we also have a $200 million five-year credit facility that supports certain Virginia Power tax-exempt financings. Our aggregate credit facility commitments of $5.6 billion are with a large consortium of banks, including Lehman Brothers Holdings Inc. (Lehman). In September 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. As of September 30, 2008, Lehman s total commitment to these credit facilities was less than five percent of the aggregate commitment from the consortium of banks. We do not believe that the potential reduction in available capacity under these credit facilities that could result from Lehman s bankruptcy will have a significant impact on our liquidity.

Long-Term Debt

In January 2008, Virginia Power borrowed $30 million in connection with the Economic Development Authority of the City of Chesapeake Pollution Control Refunding Revenue Bonds, Series 2008 A, which mature in 2032 and bear an initial coupon rate of 3.6% for the first five years, after which they will bear interest at a market rate to be determined at that time. The proceeds were used to refund the principal amount of the Industrial Development Authority of the City of Chesapeake Money Market Municipals Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in February 2008.

In April 2008, Virginia Power issued $600 million of 5.4% senior notes that mature in 2018. The proceeds were used for general corporate purposes, including the repayment of short-term debt and the redemption of all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities (including the related $412 million 7.375% unsecured Junior Subordinated Notes) due July 30, 2042. These securities were called for redemption in April 2008 and redeemed in May 2008 at a price of $25 per preferred security plus accrued and unpaid distributions.

In June 2008, Dominion issued $500 million of 6.4% senior notes that mature in 2018, $400 million of 7.0% senior notes that mature in 2038 and $300 million of floating rate senior notes that mature in 2010 and bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 1.05%, reset quarterly. We used the proceeds for general corporate purposes, including the repayment of short-term debt.

Including the amounts discussed above, we repaid $1.3 billion of long-term debt and notes payable during the nine months ended September 30, 2008.

Convertible Securities

In December 2003, we issued $220 million of contingent convertible senior notes that are convertible by holders into a combination of cash and shares of our common stock under certain circumstances. In 2004 and 2005, we entered into exchange transactions with respect to these contingent convertible senior notes in contemplation of EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases. As of September 30, 2008, the conversion rate has been adjusted to 27.6703 shares of common stock per $1,000 principal amount of senior notes, primarily due to individual dividend payments above the level paid at issuance, which represents a conversion price of $36.14.

The new notes have been included in the diluted EPS calculation using the method described in EITF 04-8 when appropriate. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price is lower than the average market price of our common stock over the period, and no adjustment when the conversion price exceeds the average market price.

As of December 31, 2007, the closing price of our common stock was equal to $44.16 per share (the applicable contingent conversion price) or higher for at least 20 out of the last 30 consecutive trading days. Therefore, the senior notes were eligible for conversion during the first quarter of 2008. During the first quarter, less than $1 million of the contingent convertible senior notes were converted by shareholders. At March 31, 2008, the applicable contingent conversion price of the notes was $43.51 per share and none of the conditions for conversion had been met, therefore the senior notes were not eligible for conversion during the second quarter of 2008. As of June 30, 2008, the closing price of our common stock was equal to $43.44 (the applicable contingent conversion price) per

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share or higher for at least 20 out of the last 30 consecutive trading days. Therefore the senior notes were eligible for conversion during the third quarter of 2008. In late September 2008, approximately $17 million of the contingent convertible senior notes were surrendered for conversion. In October 2008, we paid approximately $17 million and issued 62,452 shares in connection with this conversion. As of September 30, 2008, the applicable contingent conversion price of the notes was $43.37 per share and none of the conditions for conversion had been met, therefore the senior notes are not eligible for conversion during the fourth quarter of 2008.

Issuance of Common Stock

During the nine months ended September 30, 2008, we issued 4.4 million shares and received cash proceeds of $178 million, through Dominion Direct®, employee savings plans and the exercise of employee stock options.

Note 16. Stock-Based Awards

Our results for the three months ended September 30, 2008 and 2007 include $10 million and $14 million, respectively, of compensation costs and $4 million and $5 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the nine months ended September 30, 2008 and 2007 include $29 million and $38 million, respectively, of compensation costs and $11 million and $14 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income. SFAS No. 123R, *Share-Based Payment*, requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. Approximately $9 million and $37 million of excess tax benefits were realized for the nine months ended September 30, 2008 and 2007, respectively.

Stock Options

The following table provides a summary of changes in amounts of stock options outstanding as of and for the nine months ended September 30, 2008:

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated Intrinsic Value(1) (millions)
Outstanding and exercisable at January 1, 2008	7,021	$ 30.46		
Exercised	**(976)**	**29.98**		**$ 14**
Forfeited/expired	**(4)**	**30.58**		
Outstanding and exercisable at September 30, 2008	**6,041**	**$ 30.54**	**2.25**	**$ 74**

(1) Intrinsic value represents the difference between the exercise price of the option and the market value of our stock.

We issue new shares to satisfy stock option exercises. We received cash proceeds from the exercise of stock options of approximately $30 million and $193 million in the nine months ended September 30, 2008 and 2007, respectively.

Restricted Stock

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the nine months ended September 30, 2008:

	Shares	Weighted-Average Grant Date Fair

	(thousands)		Value
Nonvested at January 1, 2008	2,014	$	35.31
Granted	**535**		**40.95**
Vested	**(882)**		**31.59**
Cancelled and forfeited	**(67)**		**39.81**
Transferred from goal-based stock to restricted stock	**200**		**34.77**
Nonvested at September 30, 2008	**1,800**	**$**	**38.58**

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As of September 30, 2008, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $32 million and is expected to be recognized over a weighted-average period of 1.6 years.

Goal-Based Stock

Goal-based stock awards are generally granted to key non-officer employees on an annual basis. The issuance of awards is based on the achievement of multiple performance metrics during a two-year period, including return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. Goal-based stock awards are also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. Current outstanding goal-based shares include awards granted in April 2007 and April 2008.

After the performance period for the April 2006 grants ended on December 31, 2007, the Compensation, Governance and Nominating Committee determined the actual performance against metrics established for those awards, and 130 thousand shares of the outstanding goal-based stock awards granted in April 2006 were converted to 200 thousand shares and transferred to restricted stock for the remaining term of the vesting period.

For remaining stock-based awards, at September 30, 2008, the targeted number of shares to be issued is 315 thousand, but the actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of goal-based stock activity for the nine months ended September 30, 2008:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2008	289	$ 39.16
Granted	**164**	**40.97**
Vested	**(1)**	**43.78**
Cancelled and forfeited	**(7)**	**43.37**
Transferred from goal-based stock to restricted stock	**(130)**	**34.77**
Nonvested at September 30, 2008	**315**	**$ 42.56**

At September 30, 2008, unrecognized compensation cost related to nonvested goal-based stock awards totaled $8 million and is expected to be recognized over a weighted-average period of 1.6 years.

Cash-Based Performance Grant

The targeted amount of the cash-based performance grant made to officers in April 2006 was $13 million, but the actual payout of the award in February 2008 determined by the Compensation, Governance and Nominating Committee was $18 million, based on the level of performance metrics achieved.

In April 2007, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2009 and is based on the achievement of two performance metrics during 2007 and 2008, return on invested capital and total shareholder return relative to that of a peer group of companies. At September 30, 2008, the targeted amount of the grant is $14 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

In April 2008, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2010 and is based on the achievement of three performance metrics during 2008 and 2009, return on invested capital, book value per share and total shareholder return relative to that of a peer group of companies. At September 30, 2008, the targeted amount of the grant is $13 million, but actual payout will vary between zero and 200% of the targeted amount depending on the level of performance metrics achieved.

At September 30, 2008, a liability of $13 million has been accrued for these awards.

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Note 17. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 24 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007, or Note 16 to our Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008, nor have any significant new matters arisen during the three months ended September 30, 2008.

Guarantees

At September 30, 2008, we had issued $413 million of guarantees to support third parties and equity method investees (issued guarantees). This includes $200 million of guarantees to support our investment in a joint venture with Shell WindEnergy Inc. (Shell) to develop a wind-turbine facility in Grant County, West Virginia (NedPower). These NedPower guarantees are primarily comprised of limited-scope guarantees and indemnifications for one-half of the project-level financing for phases one and two of the NedPower wind farm, which would require us to repay one-half of NedPower s debt, only if it is unable to do so, as a direct result of an unfavorable ruling associated with current litigation seeking to halt the project. These litigation-related guarantees will terminate when a final non-appealable ruling in favor of the project is received. We do not expect an unfavorable ruling and no significant amounts have been recorded. Our exposure under these litigation-related guarantees totaled $141 million as of September 30, 2008 and will increase to $166 million during the remainder of 2008 based upon NedPower s future expected borrowings to complete phase two. Shell has provided an identical guarantee for the other one-half of NedPower s borrowings.

Issued guarantees also include $163 million of guarantees to support our investment in a joint venture with BP Alternative Energy Inc. (BP) to develop a wind-turbine facility in Benton County, Indiana, referred to as the Fowler Ridge wind farm. The guarantees primarily relate to payments for wind turbines and construction costs. Our exposure under these guarantees was $57 million as of September 30, 2008 and will largely decline during the remainder of 2008, as the joint venture makes the underlying payments covered by these guarantees. BP has provided identical guarantees for the other one-half of these joint venture commitments.

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We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At September 30, 2008, we had issued the following subsidiary guarantees:

	Stated Limit	Value[1]
(millions)		
Subsidiary debt[2]	$ 74	$ 74
Commodity transactions[3]	3,133	441
Lease obligation for power generation facility[4]	891	891
Nuclear obligations[5]	413	302
Cove Point LNG facility[6]	770	717
Other	263	161
Total	$ 5,544	$ 2,586

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of September 30, 2008, based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.
(2) Guarantees of debt of certain DEI subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amount.
(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.
(4) Guarantee of a DEI subsidiary s leasing obligation for the Fairless Energy power station.
(5) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to $150 million and $60 million to two DEI subsidiaries, to pay the operating expenses of the Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage, as part of satisfying certain Nuclear Regulatory Commission (NRC) requirements concerned with ensuring adequate funding for the operations of nuclear power stations.
(6) Includes a $700 million payment and performance guarantee related to the expansion of our Cove Point LNG facility.

Surety Bonds and Letters of Credit

As of September 30, 2008, we had purchased $163 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $298 million to facilitate commercial transactions by our subsidiaries with third parties.

Litigation

In 2006, Gary P. Jones and others filed suit against DTI, DEPI and Dominion Resources Services, Inc. (DRS). The plaintiffs are royalty owners, seeking to recover damages as a result of the Dominion defendants allegedly underpaying royalties by improperly deducting post-production costs and not paying fair market value for the gas produced from their leases. The plaintiffs seek class action status on behalf of all West Virginia residents and others who are parties to, or beneficiaries of, oil and gas leases with the Dominion defendants. DRS is erroneously named as a defendant, as the parent company of DTI and DEPI. During 2007, we established a litigation reserve representing our best estimate of the probable loss related to this matter. We do not believe that the final resolution of this matter will have a material adverse effect on our results of operations or financial condition. By order dated July 16, 2008, the Court preliminarily approved settlement of the class action and conditionally certified a temporary settlement class. The Court also dismissed DRS and added Dominion Appalachian Development LLC as a defendant for the sole purpose of settling the class claims. Following preliminary approval by the Court, settlement notices were sent out to potential class members. Class members have until November 1, 2008 to opt out of the class. A final fairness hearing is scheduled for January 21, 2009.

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Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contracts with the DOE. In January 2004, we and certain of our direct and indirect subsidiaries filed lawsuits in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for us in the amount of approximately $155 million for our spent fuel-related costs through June 30, 2006. The DOE has 60 days from the entry of a judgment to file an appeal and is expected to appeal the decision. We cannot predict the outcome of this matter, however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Note 18. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our September 30, 2008 provision for credit losses, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. and Texas. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our energy marketing and price risk management activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At September 30, 2008, our gross credit exposure totaled $863 million. After the application of collateral, our credit exposure was reduced to approximately $827 million. Of this amount, investment grade counterparties, including those internally rated, represented 94% and no single counterparty exceeded 14%.

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Note 19. Employee Benefit Plans

The components of the provision for net periodic benefit cost (credit) were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
(millions)				
Three Months Ended September 30,				
Service cost	**$ 25**	$ 36	**$ 13**	$ 13
Interest cost	**57**	70	**19**	20
Expected return on plan assets	**(99)**	(124)	**(14)**	(17)
Amortization of prior service cost (credit)	**1**		**(1)**	(1)
Amortization of net loss	**1**	12	**1**	2
Settlements and curtailments(1)				(1)
Net periodic benefit cost (credit)	**$ (15)**	$ (6)	**$ 18**	$ 16
Nine Months Ended September 30,				
Service cost	**$ 77**	$ 89	**$ 43**	$ 41
Interest cost	**178**	172	**66**	58
Expected return on plan assets	**(310)**	(305)	**(52)**	(53)
Amortization of prior service cost (credit)	**3**	2	**(4)**	(4)
Amortization of transition obligation				2
Amortization of net loss	**5**	30	**5**	5
Benefit enhancement(2)		3		9
Settlements and curtailments(1)		7		(1)
Net periodic benefit cost (credit)	**$ (47)**	$ (2)	**$ 58**	$ 57

(1) Relates to the then-pending sale of Peoples and Hope and the sale of our non-Appalachian E&P operations.
(2) Reflects a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P operations.

Employer Contributions

Under our funding policies, we evaluate pension and other postretirement benefit plan funding requirements annually, usually in the second half of the year after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, the amount of additional contributions to be made each year is determined at that time. We made no contributions to our defined benefit pension plans or other postretirement benefit plans during the nine months ended September 30, 2008. We do not expect to make any contributions to our pension plans in 2008, but we do expect to contribute approximately $36 million to our other postretirement benefit plans during the fourth quarter of 2008.

Note 20. Operating Segments

We are organized primarily on the basis of the products and services we sell. We manage our daily operations through the following segments.

DVP includes our regulated electric transmission, distribution and customer service operations, as well as our nonregulated retail energy marketing operations.

Dominion Energy includes our Ohio regulated natural gas distribution company, regulated gas transmission pipeline and storage operations, including gathering and extraction activities, regulated LNG operations and our remaining E&P operations. Dominion Energy also includes producer services, which aggregates gas supply, engages in gas trading and marketing activities, provides market-based services related to fuel and gas supply management, and supplies price risk management services to Dominion affiliates.

Dominion Generation includes the electric generation operations of our utility and merchant fleet, as well as energy marketing and price risk management activities associated with our generation assets.

Corporate and Other includes our corporate, service company and other functions (including unallocated debt), the remaining assets and operations of DCI, the net impact of discontinued operations, our divested U.S. E&P operations, and Peoples and Hope. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings.

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As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments and are instead reported in the Corporate and Other segment. In the nine months ended September 30, 2008 and 2007, our Corporate and Other segment included $54 million and $616 million, respectively, of after-tax expenses attributable to our operating segments:

The expenses in 2008 primarily reflect $83 million ($50 million after-tax) of impairment charges resulting from other-than-temporary declines in the fair value of securities held in merchant nuclear decommissioning trust funds, attributable to Dominion Generation.

The expenses in 2007 largely resulted from the following items attributable to Dominion Generation:

A $387 million ($252 million after-tax) charge related to the impairment of Dresden;

A $259 million ($158 million after-tax) extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations; and

A $236 million ($140 million after-tax) charge in connection with the termination of a long-term power sales agreement at State Line.

Intersegment sales and transfers are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

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The following table presents segment information pertaining to our operations:

	DVP	Dominion Energy	Dominion Generation	Corporate and Other	Adjustments/ Eliminations	Consolidated Total
(millions)						
Three Months Ended September 30,						
2008						
Total revenue from external customers	**$ 595**	**$ 334**	**$ 2,693**	**$ 37**	**$ 572**	**$ 4,231**
Intersegment revenue	**18**	**624**	**17**	**198**	**(857)**	
Total operating revenue	**613**	**958**	**2,710**	**235**	**(285)**	**4,231**
Net income (loss)	**84**	**81**	**449**	**(106)**		**508**
2007						
Total revenue from external customers	$ 579	$ 209	$ 2,229	$ 220	$ 352	$ 3,589
Intersegment revenue	12	455	31	143	(641)	
Total operating revenue	591	664	2,260	363	(289)	3,589
Loss from discontinued operations, net of tax				(3)		(3)
Net income	103	66	403	1,745		2,317
Nine Months Ended September 30,						
2008						
Total revenue from external customers	**$ 2,129**	**$ 1,639**	**$ 6,507**	**$ 461**	**$ 1,336**	**$ 12,072**
Intersegment revenue	**109**	**1,497**	**63**	**509**	**(2,178)**	
Total operating revenue	**2,238**	**3,136**	**6,570**	**970**	**(842)**	**12,072**
Loss from discontinued operations, net of tax				**(2)**		**(2)**
Net income (loss)	**278**	**333**	**991**	**(116)**		**1,486**
2007						
Total revenue from external customers	$ 2,057	$ 1,340	$ 5,745	$ 1,905	$ 933	$ 11,980
Intersegment revenue	84	1,171	98	412	(1,765)	
Total operating revenue	2,141	2,511	5,843	2,317	(832)	11,980
Extraordinary item, net of tax				(158)		(158)
Loss from discontinued operations, net of tax				(5)		(5)
Net income	333	274	623	1,010		2,240

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DOMINION RESOURCES, INC.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

MD&A discusses our results of operations and general financial condition. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their may represent any of the following: the legal entity, Dominion Resources, Inc., one or more of Dominion Resources, Inc. s consolidated subsidiaries or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Contents of MD&A

Our MD&A consists of the following information:

- Forward-Looking Statements
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information Energy Trading Activities
- Liquidity and Capital Resources
- Future Issues and Other Matters

Forward-Looking Statements

This report contains statements concerning our expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as anticipate, estimate, forecast, expect, believe, shoulc could, plan, may, target or other similar words.

We make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;

Extreme weather events, including hurricanes and severe storms, that can cause outages and property damage to our facilities;

State and federal legislative and regulatory developments and changes to environmental and other laws and regulations, including those related to climate change, greenhouse gases and other emissions, to which we are subject;

Cost of environmental compliance, including those costs related to climate change;

Risks associated with the operation of nuclear facilities;

Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;

Counterparty credit risk;

Risks associated with our membership and participation in RTOs related to obligations created by the default of other participants;

Capital market conditions, including the availability of credit and our ability to obtain financing on reasonable terms;

Price risk due to securities held as investments in nuclear decommissioning and benefit plan trusts;

Fluctuations in interest rates;

Changes in federal and state tax laws and regulations;

Changes to benefit plan assumptions such as discount rates and the expected rate of return on plan assets;

Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;

Changes in financial or regulatory accounting principles or policies imposed by governing bodies;

Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;

The risks of operating businesses in regulated industries that are subject to changing regulatory structures;

Changes to the regulated gas and electric rates we collect and the timing of such collection as it relates to fuel costs;

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Receipt of approvals for and timing of closing dates for acquisitions and divestitures;

Changes in rules for RTOs in which we participate, including changes in rate designs and capacity models;

Adverse outcomes in litigation matters;

Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;

Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;

The inability to complete planned construction or expansion projects within the terms and time frames initially anticipated; and

Completing the divestiture of Peoples and Hope.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in this report, in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008, and in our Annual Report on Form 10-K for the year ended December 31, 2007.

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

Accounting Matters

Critical Accounting Policies and Estimates

As of September 30, 2008, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, regulated operations, asset retirement obligations, employee benefit plans, gas and oil operations, and income taxes.

Other

See Notes 3 and 4 to our Consolidated Financial Statements for a discussion of newly adopted and recently issued accounting standards. See Note 11 to our Consolidated Financial Statements for information on our fair value measurements.

Results of Operations

Presented below is a summary of our consolidated results for the quarter and year-to-date periods ended September 30, 2008 and 2007:

	2008	**2007**	**$ Change**
(millions, except EPS)			
Third Quarter			
Net income	**$ 508**	$ 2,317	$ (1,809)
Diluted EPS	**0.87**	3.62	(2.75)

Year-To-Date			
Net income	**$ 1,486**	$ 2,240	$ (754)
Diluted EPS	**2.56**	3.29	(0.73)

Overview

Third Quarter 2008 vs. 2007

Net income decreased by 78% to $508 million. The decrease primarily reflects the absence of a $2.1 billion after-tax gain on the sale of our U.S. non-Appalachian E&P business, partially offset by the absence of charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007 and the termination of a long-term power sales agreement at State Line in 2007 and higher contributions from our merchant generation operations in 2008. Diluted EPS decreased to $0.87 and includes $0.08 of share accretion resulting from the repurchase of shares in 2007 with proceeds received from the sale of the majority of our E&P operations.

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Year-to-Date 2008 vs. 2007

Net income decreased by 34% to $1.5 billion. Unfavorable drivers include the absence of a $2.1 billion after-tax gain on the sale of our U.S. non-Appalachian E&P business and the absence of ongoing earnings from this business due to the sale. Favorable drivers include the absence of the following 2007 items:

Charges related to the sale of the majority of our E&P operations;

An impairment charge related to the sale of Dresden;

An extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations; and

A charge in connection with the termination of a long-term power sales agreement at State Line.

Additional favorable drivers include the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our utility generation operations effective July 1, 2007, a higher contribution from our merchant generation operations and the reversal of deferred tax liabilities associated with the planned sale of Peoples and Hope. Diluted EPS decreased to $2.56 and includes $0.38 of share accretion resulting from the repurchase of shares in 2007 with proceeds received from the sale of the majority of our E&P operations.

Analysis of Consolidated Operations

Presented below are selected amounts related to our results of operations.

	Third Quarter			Year-To-Date		
	2008	**2007**	**$ Change**	**2008**	**2007**	**$ Change**
(millions)						
Operating Revenue	**$ 4,231**	$ 3,589	$ 642	**$ 12,072**	$ 11,980	$ 92
Operating Expenses						
Electric fuel and energy purchases	**1,370**	914	456	**3,006**	2,742	264
Purchased electric capacity	**102**	111	(9)	**306**	339	(33)
Purchased gas	**593**	346	247	**2,469**	2,024	445
Other energy-related commodity purchases	**9**	64	(55)	**43**	184	(141)
Other operations and maintenance	**689**	1,159	(470)	**2,236**	3,906	(1,670)
Gain on sale of U.S. non-Appalachian E&P business	**42**	(3,617)	3,659	**42**	(3,602)	3,644
Depreciation, depletion and amortization	**259**	284	(25)	**770**	1,116	(346)
Other taxes	**112**	113	(1)	**375**	436	(61)
Other income	**14**	33	(19)	**10**	125	(115)
Interest and related charges	**217**	437	(220)	**646**	974	(328)
Income tax expense	**344**	1,498	(1,154)	**701**	1,576	(875)
Extraordinary item, net of tax					(158)	158

An analysis of our results of operations for the third quarter and year-to-date periods of 2008 as compared to 2007 follows:

Third Quarter 2008 vs. 2007

Operating Revenue increased 18% to $4.2 billion, primarily reflecting:

A $347 million increase in revenue from our electric utility operations resulting primarily from an increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions that was offset by a corresponding increase in *Electric fuel and energy purchases expense*;

A $178 million increase in our producer services business primarily as a result of an increase in prices realized for gas aggregation activities and favorable price changes associated with gas trading activities;

A $157 million increase for merchant generation operations primarily reflecting higher realized prices for nuclear and fossil operations; and

An $89 million increase in gas sales by our gas distribution operations, primarily due to the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier.

These increases were partially offset by:

A $136 million decrease due to the sale of the majority of our U.S. E&P operations; and

A $51 million decrease in nonutility coal sales related to exiting this activity.

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Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 50% to $1.4 billion, primarily reflecting the combined effects of:

- A $367 million increase for our utility generation operations primarily reflecting a comparatively higher fuel rate in certain customer jurisdictions, as discussed in *Operating Revenue*; and
- A $60 million increase for our merchant generation operations primarily reflecting increased consumption ($43 million) and higher commodity prices ($13 million) at certain fossil generation facilities.

Purchased gas expense increased 71% to $593 million, principally resulting from the following factors:

- A $126 million increase in our producer services business primarily as a result of an increase in prices ($103 million) and volumes ($23 million) associated with gas aggregation and marketing activities; and
- A $92 million increase in the cost of gas sold by our gas distribution operations, primarily due to the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier.

Other energy-related commodity purchases expense decreased 86% to $9 million, primarily due to a $53 million decrease in the cost of nonutility coal sales related to exiting this activity.

Other operations and maintenance expense decreased 41% to $689 million, primarily reflecting the combined effects of:

- The absence of a $236 million charge in connection with the termination of a long-term power sales agreement at State Line in 2007;
- A $106 million decrease reflecting the sale of the majority of our U.S. E&P operations, including the absence of charges incurred in 2007 in connection with the sale; and
- The absence of $86 million of impairment charges in 2007 related to DCI investments.

Gain on sale of U.S. non-Appalachian E&P business primarily reflects the absence of the gain of $3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business in 2007.

DD&A decreased 9% to $259 million, principally due to decreased gas and oil production resulting from the sale of the majority of our U.S. E&P operations, partially offset by property additions and an increase in depreciation rates for our utility generation assets.

Other income decreased by 58% to $14 million, primarily due to higher other-than-temporary impairments for merchant nuclear decommissioning trust investments.

Interest and related charges decreased 50% to $217 million resulting principally from the absence of charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007.

Income tax expense decreased by 77% to $344 million, primarily due to lower pre-tax income in 2008 largely reflecting the absence of the gain realized in 2007 from the sale of our U.S. non-Appalachian E&P business.

Year-To-Date 2008 vs. 2007

Operating Revenue increased 1% to $12.1 billion, primarily reflecting:

- A $561 million increase in revenue from our electric utility operations resulting primarily from an increase in fuel revenue largely due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;

- A $365 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations ($430 million), partially offset by lower overall volumes due to outages at certain fossil generating facilities ($65 million);

- A $254 million increase in our producer services business primarily as a result of an increase in prices realized for gas aggregation activities and favorable price changes associated with gas trading activities;

- A $164 million increase in sales of gas production from our remaining E&P operations, primarily due to:

  - An $89 million increase in sales from our Appalachian properties due to higher prices ($66 million) and increased production ($23 million); and

  - Increased production associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007 ($71 million).

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A $90 million increase in nonregulated gas sales by our gas distribution operations, primarily due to the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier;

A $69 million increase in regulated gas sales attributable to our gas distribution operations primarily resulting from the net impact of higher prices ($94 million) partially offset by lower volumes and changes in customer usage patterns and other factors ($25 million);

A $57 million increase in gas transportation and storage revenue primarily due to a $32 million increase in revenue from our gas distribution operations due to higher prices and a $27 million increase attributable to our gas transmission operations primarily reflecting increased rates for certain storage activities and gathering and extraction services; and

A $47 million increase in sales of extracted products from our gas transmission operations as a result of higher realized prices.

These increases were partially offset by:

A $1.4 billion decrease due to the sale of the majority of our U.S. E&P operations; and

A $141 million decrease in nonutility coal sales related to exiting this activity.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 10% to $3.0 billion, primarily reflecting the combined effects of:

A $109 million increase for our utility generation operations. This increase was largely due to a $470 million increase in fuel costs, primarily as a result of higher commodity prices, including purchased power. The increase in fuel costs was partially offset by the deferral of fuel expenses that were in excess of the current period fuel rate recovery ($361 million); and

A $103 million increase for our merchant generation operations primarily reflecting the impact of higher commodity prices ($59 million) and increased consumption ($44 million) at certain fossil generation facilities.

Purchased gas expense increased 22% to $2.5 billion, primarily due to the following factors:

A $241 million increase for our producer services business primarily as a result of an increase in prices associated with gas aggregation and marketing activities; and

A $145 million increase in the cost of gas sold by our gas distribution operations primarily reflecting the combined effects of the following:

- A $103 million increase due to higher prices; and
- A $42 million increase in volumes due to the net impact of the sale of gas inventory by Dominion East Ohio related to its plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier partially offset by lower sales for our regulated gas distribution operations.

Other energy-related commodity purchases expense decreased 77% to $43 million, primarily due to a $140 million decrease in the cost of nonutility coal sales volumes related to exiting this activity.

Other operations and maintenance expense decreased 43% to $2.2 billion, primarily reflecting the combined effects of:

- A $1.1 billion decrease reflecting the sale of the majority of our U.S. E&P operations, including the absence of charges incurred in 2007 in connection with the sale;
- The absence of a $387 million impairment charge in 2007 related to the sale of Dresden; and
- The absence of a $236 million charge in connection with the termination of a long-term power sales agreement at State Line in 2007; partially offset by
- A $73 million increase in outage costs primarily reflecting an increase in scheduled merchant nuclear and fossil outages, partially offset by fewer scheduled utility generation outages.

Gain on sale of U.S. non-Appalachian E&P business primarily reflects the absence of the gain of $3.6 billion resulting from the completion of the sale of our U.S. non-Appalachian E&P business in 2007.

DD&A decreased 31% to $770 million, principally due to decreased gas and oil production resulting from the sale of the majority of our U.S. E&P operations in 2007, partially offset by an increase in production from our remaining E&P operations, property additions and an increase in depreciation rates for our utility generation assets.

Other taxes decreased 14% to $375 million primarily due to lower severance and property taxes resulting from the sale of the majority of our U.S. E&P operations in 2007.

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Other income decreased by 92% to $10 million, primarily due to higher other-than-temporary impairments for merchant nuclear decommissioning trust investments.

Interest and related charges decreased 34% to $646 million, resulting principally from the absence of charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007.

Income tax expense decreased by 56% to $701 million, primarily due to lower pre-tax income in 2008 largely reflecting the absence of the gain realized in 2007 from the sale of our U.S. non-Appalachian E&P business.

Extraordinary item reflects the absence of a $158 million after-tax charge in 2007 in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by our operating segments to net income for the quarter and year-to-date periods ended September 30, 2008 and 2007:

	Net Income			Diluted EPS		
Third Quarter	**2008**	**2007**	**$ Change**	**2008**	**2007**	**$ Change**
(millions, except EPS)						
DVP	**$ 84**	$ 103	$ (19)	**$ 0.15**	$ 0.16	$ (0.01)
Dominion Energy	**81**	66	15	**0.14**	0.10	0.04
Dominion Generation	**449**	403	46	**0.77**	0.63	0.14
Primary operating segments	**614**	572	42	**1.06**	0.89	0.17
Corporate and Other	**(106)**	1,745	(1,851)	**(0.19)**	2.73	(2.92)
Consolidated	**$ 508**	$ 2,317	$ (1,809)	**$ 0.87**	$ 3.62	$ (2.75)
Year-To-Date						
(millions, except EPS)						
DVP	**$ 278**	$ 333	$ (55)	**$ 0.48**	$ 0.49	$ (0.01)
Dominion Energy	**333**	274	59	**0.57**	0.40	0.17
Dominion Generation	**991**	623	368	**1.71**	0.91	0.80
Primary operating segments	**1,602**	1,230	372	**2.76**	1.80	0.96
Corporate and Other	**(116)**	1,010	(1,126)	**(0.20)**	1.49	(1.69)
Consolidated	**$ 1,486**	$ 2,240	$ (754)	**$ 2.56**	$ 3.29	$ (0.73)

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DVP

Presented below are operating statistics related to DVP s operations:

	Third Quarter			Year-To-Date		
	2008	**2007**	**% Change**	**2008**	**2007**	**% Change**
Electricity delivered (million mwhrs)	**23.4**	23.7	(1)%	**64.2**	64.7	(1)%
Degree days (electric distribution service area):						
Cooling(1)	**1,083**	1,150	(6)	**1,587**	1,643	(3)
Heating(2)	**2**	5	(60)	**2,074**	2,365	(12)
Average electric distribution customer accounts(3)	**2,387**	2,364	1	**2,383**	2,357	1
Average retail energy marketing customer accounts(3)	**1,617**	1,566	3	**1,601**	1,529	5

mwhrs = megawatt hours

(1) Cooling degree days (CDDs) are units measuring the extent to which the average daily temperature is greater than 65 degrees. CDDs are calculated as the difference between the average temperature for each day and 65 degrees.
(2) Heating degree days (HDDs) are units measuring the extent to which the average daily temperature is less than 65 degrees. HDDs are calculated as the difference between the average temperature for each day and 65 degrees.
(3) Period average, in thousands.

Presented below, on an after-tax basis, are the key factors impacting DVP s net income contribution:

	Third Quarter 2008 vs. 2007 Increase (Decrease)		Year-To-Date 2008 vs. 2007 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Regulated electric sales:				
Weather	$ (7)	$ (0.01)	$ (15)	$ (0.02)
Customer growth	2		7	0.01
Other	(3)		(1)	
Retail energy marketing operations	(6)	(0.01)	4	0.01
Interest expense	(2)		(11)	(0.02)
Depreciation and amortization	(2)		(5)	(0.01)
Storm damage and service restoration distribution operations			(11)	(0.02)
Operations and maintenance(1)	4	0.01	(13)	(0.02)
Other	(5)	(0.01)	(10)	(0.01)
Share accretion		0.01		0.07
Change in net income contribution	$ (19)	$ (0.01)	$ (55)	$ (0.01)

(1) For the year-to-date period, primarily reflects increases in salaries, wages and benefits, outside contractor services and general administrative costs.

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Dominion Energy

Presented below are operating statistics related to our Dominion Energy operations:

	Third Quarter			Year-To-Date		
	2008	**2007**	**% Change**	**2008**	**2007**	**% Change**
Gas distribution throughput (bcf):						
Sales	**3**	3	%	**35**	36	(3)%
Transportation	**28**	26	8	**156**	152	3
HDDs (gas distribution service area)	**54**	72	(25)	**3,929**	3,964	(1)
Average gas distribution customer accounts[1]						
Sales	**384**	406	(5)	**396**	412	(4)
Transportation	**802**	791	1	**807**	799	1
Production[2] (bcfe)	**15.2**	17.2	(12)	**49.2**	39.6	24
Average realized prices without hedging results (per mcfe)	**$ 9.94**	$ 5.83	70	**$ 9.39**	$ 6.48	45
Average realized prices with hedging results (per mcfe)	**8.54**	6.61	29	**8.61**	6.37	35
DD&A (unit of production rate per mcfe)	**2.06**	1.63	26	**1.98**	1.58	25
Average production (lifting) cost[3] (per mcfe)	**1.51**	1.33	14	**1.35**	1.30	4

bcf = billion cubic feet

bcfe = billion cubic feet equivalent

mcfe = thousand cubic feet equivalent

(1) Period average, in thousands.
(2) Includes natural gas, natural gas liquids and oil. Production includes 3.5 bcfe and 14.4 bcfe for the quarter and year-to-date periods ended September 30, 2008, respectively, and 6.7 bcfe and 9.0 bcfe for the quarter and year-to-date periods ended September 30, 2007, respectively, associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.
(3) The inclusion of volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007 would have resulted in lifting costs of $1.26 and $1.07 for the quarter and year-to-date periods ended September 30, 2008, respectively, and $0.86 and $1.03 for the quarter and year-to-date periods ended September 30, 2007, respectively.

Presented below, on an after-tax basis, are the key factors impacting Dominion Energy s net income contribution:

	Third Quarter 2008 vs. 2007 Increase (Decrease)		Year-To-Date 2008 vs. 2007 Increase (Decrease)	
	Amount	**EPS**	**Amount**	**EPS**
(millions, except EPS)				
Producer services[1]	$ 15	$ 0.03	$ (6)	$ (0.01)
Gas and oil prices	14	0.02	48	0.07
Gas and oil production[2]	(6)	(0.01)	43	0.06
DD&A gas and oil	(2)		(21)	(0.03)
Other	(6)	(0.01)	(5)	(0.01)
Share accretion		0.01		0.09
Change in net income contribution	$ 15	$ 0.04	$ 59	$ 0.17

(1) For the quarter, increase is primarily due to higher income related to the impact of favorable price changes associated with gas trading, storage and affiliated price risk management services, partially offset by losses associated with physical gas transportation margins.

(2) For the year-to-date period, increase primarily reflects the inclusion of volumes associated with reacquired overriding royalty interests arising from the VPPs terminated in 2007.

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Included below are the volumes and weighted-average prices associated with hedges in place for our E&P operations and fixed-term overriding royalty interests formerly associated with VPP agreements as of September 30, 2008, by applicable time period:

Year	Natural Gas Hedged Production (bcf)	Natural Gas Average Hedge Price (per mcf)
2008	13.6	$ 8.94
2009	31.7	9.08
2010	12.7	8.60

mcf = thousand cubic feet

Dominion Generation

Presented below are operating statistics related to our Dominion Generation operations:

	Third Quarter 2008	Third Quarter 2007	Third Quarter % Change	Year-To-Date 2008	Year-To-Date 2007	Year-To-Date % Change
Electricity supplied (million mwhrs)						
Utility	**23.4**	23.7	(1)%	**64.2**	64.7	(1)%
Merchant	**12.4**	12.7	(2)	**33.4**	34.2	(2)
Degree days (electric utility service area):						
Cooling	**1,083**	1,150	(6)	**1,587**	1,643	(3)
Heating	**2**	5	(60)	**2,074**	2,365	(12)

Presented below, on an after-tax basis, are the key factors impacting Dominion Generation s net income contribution:

	Third Quarter 2008 vs. 2007 Increase (Decrease) Amount	Third Quarter 2008 vs. 2007 Increase (Decrease) EPS	Year-To-Date 2008 vs. 2007 Increase (Decrease) Amount	Year-To-Date 2008 vs. 2007 Increase (Decrease) EPS
(millions, except EPS)				
Merchant generation margin[1]	$ 67	$ 0.10	$ 154	$ 0.22
Regulated electric sales:				
Customer growth	5	0.01	13	0.02
Weather	(16)	(0.03)	(29)	(0.04)
Other	4	0.01	34	0.05
Virginia fuel expenses[2]			243	0.36
Sales of emissions allowances			18	0.03
Depreciation and amortization	(8)	(0.01)	(28)	(0.04)
Outage costs	(2)		(50)	(0.07)
Other	(4)	(0.01)	13	0.02
Share accretion		0.07		0.25
Change in net income contribution	$ 46	$ 0.14	$ 368	$ 0.80

(1) Primarily reflects higher realized prices, partially offset by higher fuel prices and lower volumes at certain generation facilities due to outages.
(2) For the year-to-date period, primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for the Virginia jurisdiction of our utility generation operations.

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Corporate and Other

Presented below are the Corporate and Other segment s after-tax results:

	Third Quarter			Year-To-Date		
	2008	**2007**	**$ Change**	**2008**	**2007**	**$ Change**
(millions, except EPS)						
Specific items attributable to operating segments	**$ (27)**	$ (178)	$ 151	**$ (54)**	$ (616)	$ 562
Discontinued operations		(3)	3	**(2)**	(5)	3
Sale of U.S. E&P business	**(26)**	1,946	(1,972)	**(26)**	1,415	(1,441)
Divested U.S. E&P operations		4	(4)		257	(257)
Peoples and Hope	**2**	(3)	5	**63**	30	33
Other corporate operations	**(55)**	(21)	(34)	**(97)**	(71)	(26)
Total net benefit (expense)	**$ (106)**	$ 1,745	$ (1,851)	**$ (116)**	$ 1,010	$ (1,126)
EPS impact	**$ (0.19)**	$ 2.73	$ (2.92)	**$ (0.20)**	$ 1.49	$ (1.69)

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded from profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 20 to our Consolidated Financial Statements for discussion of these items.

Sale of U.S. E&P business

The sale of our U.S. non-Appalachian E&P business for the 2007 quarter and year-to-date periods primarily reflects the $2.1 billion after-tax gain recognized in 2007 on the sale, partially offset by charges related to the divestitures as well as charges associated with the early retirement of debt with proceeds from the sale. The 2008 quarter and year-to-date amounts reflect post-closing adjustments to the gain on the sale.

Divested U.S. E&P operations

Year-to-date 2008 vs. 2007

The decrease is due to the disposition of these operations in the third quarter of 2007.

Peoples and Hope

Year-to-date 2008 vs. 2007

The net benefit related to Peoples and Hope increased primarily due to the re-establishment of a regulatory asset in connection with the agreement to sell these subsidiaries to BBIFNA.

Other Corporate Operations

Third Quarter 2008 vs. 2007

Net expenses increased $34 million, primarily due to higher income tax benefits in 2007 related to the interim impact of changes in our estimated annual effective tax rate and the impact of Massachusetts tax legislation enacted in July 2008. The increase in net expenses also reflects the absence of interest income earned on the proceeds from the sale of our non-Appalachian E&P business in the third quarter of 2007. These increases were partially offset by the absence of an $86 million ($55 million after-tax) impairment charge in 2007 related to certain DCI investments and the impact of favorable changes in the fair value of a gas contract for which we discontinued hedge accounting as a result of the sale of our U.S. non-Appalachian E&P business in 2007.

Year-to-date 2008 vs. 2007

Net expenses increased $26 million, primarily reflecting a decrease in tax benefits and the absence of interest income earned on the proceeds received from the sale of our non-Appalachian E&P business in 2007. The decrease in tax benefits primarily reflects the net impact of the following items:

A decrease in state tax benefits, including the impact of Massachusetts tax legislation enacted in July 2008; and

The absence of tax benefits from the elimination of valuation allowances on federal and state tax loss carryforwards in 2007, partially offset by

An increase in tax benefits due to the reversal of deferred tax liabilities associated with Peoples and Hope in the first quarter of 2008.

The increase in net expenses was partially offset by the impact of lower impairment charges in 2008 related to the disposition of certain DCI investments.

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Selected Information Energy Trading Activities

See *Selected Information-Energy Trading Activities* in MD&A included in our Annual Report on Form 10-K for the year ended December 31, 2007 for a discussion of our energy trading, hedging and marketing activities and related accounting policies. For additional discussion of trading activities, see *Market Risk Sensitive Instruments and Risk Management* in Item 3.

A summary of the changes in unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the nine months ended September 30, 2008 follows:

	Amount
(millions)	
Net unrealized gain at December 31, 2007	$ 52
Contracts realized or otherwise settled during the period	**(34)**
Net unrealized gain at inception of contracts initiated during the period	
Changes in valuation techniques	
Other changes in fair value	**16**
Net unrealized gain at September 30, 2008	**$ 34**

The fair values summarized below were determined in accordance with the requirements of SFAS No. 157, which we adopted effective January 1, 2008. In addition, we aligned the categories below with the Level 1, 2, and 3 fair value measurements as defined by SFAS No. 157. The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at September 30, 2008, is summarized in the following table based on the inputs used to determine fair value:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value	**Less than 1 year**	**1-2 years**	**2-3 years**	**3-5 years**	**In excess of 5 years**	**Total**
(millions)						
Actively quoted Level 1[(1)]	$ 1	$	$	$	$	$ 1
Other external sources Level 2[(2)]	18	2	(1)			19
Models and other valuation methods Level 3[(3)]	5	4	3	2		14
Total	$ 24	$ 6	$ 2	$ 2	$	$ 34

(1) Values represent observable unadjusted quoted prices for traded instruments in active markets.
(2) Values with inputs that are observable directly or indirectly for the instrument, but do not qualify for Level 1.
(3) Values with a significant amount of inputs that are not observable for the instrument.

Liquidity and Capital Resources

We depend on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

Impact of Recent Credit Market Events

Despite recent disruptions in the credit markets, we have sufficient access to liquidity for our daily operations through our credit facilities discussed in Note 15 to our Consolidated Financial Statements. While we continue to issue commercial paper, in October 2008 we borrowed $870 million from our credit facilities to reduce our exposure to the commercial paper market. We expect our operations to provide sufficient cash flow to fund maintenance capital expenditures and maintain or grow our dividend; however we expect to access the capital markets to fund growth capital expenditures. If necessary, we have the flexibility to mitigate the need for future debt financings and equity issuances, by postponing or cancelling certain planned capital expenditures without significantly impacting our earnings per share growth plans over the next several years. However, a material reduction or delay in growth projects would likely reduce our earnings per share growth rate longer term.

At September 30, 2008, we had $2.7 billion of unused capacity under our credit facilities.

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A summary of our cash flows for the nine months ended September 30, 2008 and 2007 is presented below:

	2008	2007
(millions)		
Cash and cash equivalents at January 1,[1]	**$ 287**	$ 142
Cash flows provided by (used in):		
Operating activities	**1,415**	2,283
Investing activities	**(2,321)**	10,814
Financing activities	**709**	(12,768)
Net decrease in cash and cash equivalents	**(197)**	329
Cash and cash equivalents at September 30,[2]	**$ 90**	$ 471

(1) 2008 and 2007 amounts include $4 million of cash classified as held for sale on our Consolidated Balance Sheets.
(2) 2008 and 2007 amounts include $2 million of cash classified as held for sale on our Consolidated Balance Sheets.

Operating Cash Flows

For the nine months ended September 30, 2008, net cash provided by operating activities decreased by $868 million as compared to the nine months ended September 30, 2007. The decrease was primarily due to a reduction in cash flow resulting from the disposition of the majority of our E&P operations in the third quarter of 2007 and higher collateral requirements related to our commodity hedging transactions, partially offset by a higher contribution from our merchant generation business. Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors in this report, our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008 and in our Annual Report on Form 10-K for the year-ended December 31, 2007.

Credit Risk

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities. Presented below is a summary of our gross credit exposure as of September 30, 2008, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade[1]	$ 528	$ 28	$ 500
Non-investment grade[2]	16		16
No external ratings:			
Internally rated investment grade[3]	287	8	279
Internally rated non-investment grade[4]	32		32
Total	$ 863	$ 36	$ 827

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s and Standard & Poor s. The five largest counterparty exposures, combined, for this category represented approximately 31% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented less than 2% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 26% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 3% of the total net credit exposure.

Investing Cash Flows

For the nine months ended September 30, 2008, net cash used in investing activities was $2.3 billion as compared to net cash provided by investing activities of $10.8 billion for the nine months ended September 30, 2007. This change is primarily due to the absence of the proceeds received in 2007 from the sales of our non-Appalachian E&P business and Peaker facilities, a reduction in capital expenditures as a result of the disposition of the majority of our E&P operations, and proceeds received from the assignment of drilling rights in the Marcellus Shale formation to Antero, partially offset by an increase in capital expenditures primarily related to our electric utility operations and our investment in wind farm facilities.

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Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by the companies operations. As discussed further in the *Credit Ratings and Debt Covenants* section, our ability to borrow funds or issue securities and the return demanded by investors are affected by the issuing company s credit ratings. In addition, the raising of external capital is subject to meeting certain regulatory requirements, including registration with the SEC and in the case of Virginia Power, approval by the Virginia Commission.

For the nine months ended September 30, 2008, net cash provided by financing activities was $709 million as compared to net cash used in financing activities of $12.8 billion for the nine months ended September 30, 2007. This change is primarily due to net issuances of common stock and short-term and long-term debt in 2008 as compared to net repurchases and repayments in 2007 reflecting the use of proceeds received in 2007 from the sale of the majority of our E&P business.

See Note 15 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007, we discussed the use of capital markets by Dominion and Virginia Power, as well as the impact of credit ratings on the accessibility and costs of using these markets. In addition, these sections of MD&A discussed various covenants present in the enabling agreements underlying Dominion and Virginia Power s debt. As of September 30, 2008, there have been no changes in our credit ratings, other than the matters discussed in MD&A in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, nor have there been any changes to or events of default under our debt covenants.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of September 30, 2008, there have been no material changes outside the ordinary course of business to our contractual obligations nor any material changes to our planned capital expenditures disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007.

Use of Off-Balance Sheet Arrangements

As of September 30, 2008, there have been no material changes in the off-balance sheet arrangements disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2007, other than the third-party guarantees discussed in Note 17 to our Consolidated Financial Statements.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with *Future Issues and Other Matters* in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008.

Marcellus Shale

We previously entered into an agreement with Antero Resources (Antero) to assign natural gas drilling rights on approximately 205,000 Appalachian Basin net acres for approximately $552 million; however, due to Antero s difficulty in obtaining follow-on financing, the amount assigned was reduced. On September 30, 2008, we completed a transaction with Antero to assign drilling rights to approximately 114,000 acres in the Marcellus Shale formation located in West Virginia and Pennsylvania. We received approximately $347 million and recognized $4 million of associated closing costs. Under the agreement, we will receive a 7.5% overriding royalty interest on future natural gas production from the assigned acreage. We will retain the drilling rights in traditional formations both above and below the Marcellus Shale interval and will continue our conventional drilling program on the acreage. The transaction is subject to post-closing title adjustments; however, any such adjustments would be settled through acreage substitution.

We follow the full cost method of accounting for gas and oil E&P activities as prescribed by the SEC. Under the full cost method of accounting, gains or losses on the sale or other disposition of gas and oil properties are not

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recognized, unless the gain or loss would significantly alter the relationship between the capitalized costs and proved reserves of natural gas and oil. We initially expected to recognize a pre-tax gain based on the terms of the initial agreement with Antero, however, due to the reduced size of the final transaction no material alteration occurred and the net proceeds were credited to the full cost pool, reducing property, plant and equipment in our Consolidated Balance Sheet. After-tax proceeds of $205 million will be used initially to reduce outstanding short-term debt.

We control drilling rights on substantial acreage in the Marcellus Shale formation. We continue to receive indications of interest in our remaining Marcellus Shale acreage and expect to pursue similar transactions.

In addition, we have announced the proposed development of the Dominion Keystone Project, an expansion of the DTI system that would transport new natural gas supplies from the Appalachian Basin to markets throughout the eastern U.S. As part of the drilling rights agreement, Antero will join DEPI as anchor tenants of the Dominion Keystone Project. DTI is negotiating binding precedent agreements with other customers interested in the new Keystone capacity following an open season that concluded in August 2008. Project timing is subject to producer drilling plans in the basin, as well as, customer demand throughout the mid-Atlantic and Northeast regions.

Regulatory Approval of Sale of Peoples and Hope

In September 2008, Peoples and BBIFNA filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by BBIFNA of all of the stock of Peoples. In October 2008, Hope and BBIFNA filed a joint petition seeking West Virginia Commission approval of the purchase by BBIFNA of all of the stock of Hope. In September 2008, Dominion and BBIFNA each filed a Premerger Notification and Report Form with the U.S. Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act (HSR Act). In October 2008, the waiting period under the HSR Act related to the proposed sale of Peoples and Hope to BBIFNA expired. The transaction is expected to close in 2009, subject to state regulatory approvals in Pennsylvania and West Virginia as well as clearance under the Exon-Florio provision of the Omnibus Trade and Competitiveness Act.

Cove Point Expansion

In 2006, FERC approved the proposed expansion of our Cove Point terminal and DTI pipeline and the commencement of construction of such project. Such expansion included the installation of two new LNG storage tanks at our Cove Point terminal, each capable of storing 160,000 cubic meters of LNG and expansion of our Cove Point pipeline to approximately 1,800,000 dekatherms per day. In addition, our DTI gas pipeline and storage system would be expanded by building 81 miles of pipeline, two compressor stations in Pennsylvania and other upgrades. We have commenced construction and anticipate that these projects will be placed into service in late 2008.

In 2007, Washington Gas Light Company (WGL) petitioned the U.S. Court of Appeals for the District of Columbia (D.C. Appeals Court) for review of FERC s orders. Prior to FERC s final order approving the Cove Point expansion, WGL had asked FERC to delay its approval based on its assertion that leaks on its system were caused by the composition of gas received from the Cove Point pipeline. FERC rejected WGL s claims, concluding that the leaks were a result of other defects in WGL s system, not the composition of the LNG received from Cove Point. In July 2008, the D.C. Appeals Court affirmed FERC s rulings on a number of important issues, including FERC s findings that the leaks were the result of defects on WGL s system and that we are not responsible for repairs. However, the court vacated FERC s orders to the extent that these orders approved the expansion and remanded the case back to FERC so that FERC could more fully explain whether the expansion could go forward without causing unsafe leakage on WGL s system.

In an order on remand issued in October 2008, FERC responded to the D.C. Appeals Court by reissuing authorizations for the construction and operation of the Cove Point and DTI facilities. FERC also capped deliveries from the Cove Point pipeline into Columbia Gas Transmission Corporation (Columbia) at currently authorized levels. FERC took this step to ensure that WGL would not be exposed to greater deliveries of regasified LNG via Columbia than it can currently receive. This limitation on deliveries to Columbia will have no impact on Cove Point s firm service obligations.

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DTI Appalachian Basin Expansion

DTI has announced the proposed development of a gas pipeline project, known as the Appalachian Gateway Project, which is designed to transport gas on a firm basis out of the Appalachian Basin in West Virginia and southwestern Pennsylvania to DTI s interconnect with Texas Eastern Transmission Corporation at Oakford, Pennsylvania. An open season for the project concluded in September 2008 and DTI is in the process of finalizing binding precedent agreements. Project timing is uncertain.

DTI is also evaluating other investments in gathering and processing facilities for wet natural gas, as a result of increased production in the region. Wet natural gas includes methane and heavier hydrocarbons such as propane, butane, isobutane and natural gasoline.

Collective Bargaining Agreements

We are currently negotiating with the International Union of Operating Engineers, Local 310 (Local 310). Local 310 represents approximately 170 employees at Kewaunee Power Station. The current labor contract, which was extended in 2007, has an effective date through October 21, 2008.

Kewaunee Power Station Operating License

In August 2008, we filed an application with the NRC to renew the Kewaunee Power Station operating license. Kewaunee is currently licensed to operate through December 21, 2013. A renewal would permit Kewaunee to operate through December 21, 2033. The NRC docketed the application in October 2008 and has begun its review. Interested persons have 60 days from the date of docketing to request a hearing, and there are other opportunities for public input as the NRC conducts its review of the application. The NRC s schedule contemplates completion of the proceeding in June 2010 if there is no hearing, and in February 2011 if a hearing is granted.

Dominion East Ohio Rate Case

In August 2007, Dominion East Ohio filed an application to increase base rates. In this rate case, Dominion East Ohio requested approval of an increase in operating revenues of approximately $73 million and proposed an increase in demand-side management spending. Subsequently, Dominion East Ohio also requested that the Ohio Commission consolidate its review of the rate case application with Dominion East Ohio s application, filed in February 2008, for approval to recover costs related to a 25-year program to replace 19% of its 21,000-mile pipeline system, which is expected to cost approximately $2.6 billion. In August 2008, Dominion East Ohio reached an agreement with intervening parties on all issues in the base rate case except for one related to rate design (Settlement Agreement).

In October 2008, the Ohio Commission issued its Opinion and Order in this case, in which the Ohio Commission approved the majority of the Settlement Agreement, but modified the allowed return on rate base from the 8.49% agreed upon in the Settlement Agreement to 8.29%. The resulting annual revenue increase approved by the Ohio Commission is approximately $37.5 million, which will be reflected in base rates commencing October 16, 2008. The Ohio Commission also approved the modified rate design supported by Ohio Commission staff and Dominion East Ohio for certain rate schedules, as well as the other terms of the Settlement Agreement, including a cost recovery mechanism for the implementation of automated meter reading equipment and a cost recovery mechanism for an initial five-year period of the pipeline replacement program. In addition, the Settlement Agreement requires Dominion East Ohio to increase its annual spending for energy conservation programs to a total of $9.5 million and to make grants totaling $1.2 million to several organizations to provide payment assistance and energy efficiency education to low-income customers. The Ohio Commission also ordered Dominion East Ohio to work in consultation with Commission staff and other parties to the case to develop a low-income pilot program under which a total of 5,000 eligible low-income, low-usage customers would receive a $4.00 reduction in their monthly service charge, as a result of implementing the new rate design.

Hope Rate Case

In October 2008, Hope filed a request with the West Virginia Commission for an increase in the base rates it charges for natural gas service. The requested new base rates would increase Hope s revenues by $34.4 million and would increase the monthly bill of the average residential customer using six mcf per month by 21 percent. The average monthly bill would increase 12 percent for commercial customers, 32.6 percent for industrial customers and 14 percent for resale customers. We expect the West Virginia Commission to hold public hearings in the near future, and then issue a decision that would affect bills next summer.

Utility Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service

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area, we will need additional generation capacity over the next ten years. We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market in Virginia. Our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008 provide a description of these projects, which are in various stages of development. The following is a discussion of certain significant developments related to such projects.

We are considering the construction of a third nuclear unit at a site located at North Anna which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) to our subsidiary, Dominion Nuclear North Anna, LLC (DNNA), for a site located at North Anna. Also in November 2007, Virginia Power, along with ODEC filed an application with the NRC for a Combined Construction Permit and Operating License (COL), which would allow us to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted our application for the COL and deemed it complete. The NRC is required to conduct a hearing in all COL proceedings. In August 2008, the Atomic Safety and Licensing Board of the NRC granted a request for a hearing on one of eight contentions filed by the Blue Ridge Environmental Defense League. The mandatory NRC hearing will be uncontested with respect to other issues. We have not yet committed to building a new nuclear unit.

In April 2008, we and DNNA filed applications with the Virginia Commission and the North Carolina Utilities Commission, seeking approval to merge DNNA into Virginia Power. The Virginia application was approved in July 2008, and the North Carolina application was approved in September 2008. Also in April 2008, we filed an application with the NRC to transfer the ESP from DNNA to us and ODEC. This application remains under consideration with the NRC, and we expect a decision in the fourth quarter of 2008.

In June 2008, the DOE issued a solicitation announcement inviting the submission of applications for loan guarantees from the DOE under its Loan Guarantee Program in support of debt financing for nuclear power facility projects in the U.S. (the Solicitation). The Solicitation is specifically designed to provide loan guarantees to support those projects that employ new or significantly improved nuclear power facility technologies. Any loan guarantee which may be issued by the DOE pursuant to the Solicitation would be backed by the full faith and credit of the U.S. government, and would provide credit enhancement for all or a portion of the debt financing an applicant would incur with respect to such a project. In August 2008, we submitted to the DOE Part I of the application, including a high-level description of the proposed nuclear unit, project eligibility, financing strategy and progress to date related to critical path schedules. We expect to submit to the DOE a Part II application by the required filing date of December 19, 2008.

North Carolina Fuel Factor

In September 2008, our electric utility subsidiary filed an application to revise our fuel factor with the North Carolina Utilities Commission, requesting an annual increase in our North Carolina fuel factor from 2.221 cents per kWh to 3.825 cents per kWh to be effective January 1, 2009. The proposal would result in an annual increase in fuel revenue of approximately $69 million for the North Carolina jurisdiction. An evidentiary hearing is scheduled for November 14, 2008.

Regional Transmission Expansion Plan

In June 2006, PJM authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects, which are designed to improve the reliability of service to our customers and the region, and are subject to applicable state and federal permits and approvals.

The first project is an approximately 270-mile 500-kilovolt (kV) transmission line that begins in southwestern Pennsylvania, crosses West Virginia, and terminates in northern Virginia, of which we will construct approximately 65 miles in Virginia (the Meadow Brook-to-Loudoun line) and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. In April 2007, we, along with Trans-Allegheny Interstate Line Company (Trans-Allegheny), filed an application with the Virginia Commission requesting approval of the proposed construction of the 65-mile transmission line in northern Virginia. In October 2008, the Virginia Commission authorized construction of the Meadow Brook-to-Loudoun line and affirmed the 65-mile route we proposed for the line which is adjacent to, or within, existing transmission line right-of-ways.

The Virginia Commission s approval of the Meadow Brook-to-Loudoun line is conditioned on the respective state

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commission approvals of both the West Virginia and Pennsylvania portions of the transmission line. The West Virginia Commission approved Trans-Allegheny s application in August 2008. Trans-Allegheny s application remains pending before the Pennsylvania Commission. The Meadow Brook-to-Loudoun line is expected to cost approximately $255 million and, subject to the receipt of all regulatory approvals, is expected to be completed in June 2011.

The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia (Carson-to-Suffolk line). This project is estimated to cost $224 million and is expected to be completed in June 2011. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the Carson-to-Suffolk line. Evidentiary hearings on the application commenced in February 2008. In May 2008 the hearing examiner filed a report finding need for and recommending approval of the line.

Application for Enhanced ROE for Electric Transmission Projects

In July 2008, we filed an application with FERC requesting a revision to our cost of service to reflect an additional return on equity (ROE) for eleven electric transmission enhancement projects. Under the proposal, our cost of transmission service would increase to include an ROE incentive adder for each of the eleven projects, beginning the date each project enters commercial operation (but not before January 1, 2009). We proposed an incentive of 150 basis points or 1.5% for four of the projects (including the Meadow Brook-to-Loudoun line and Carson-to-Suffolk line) and an incentive of 125 basis points or 1.25% for the other seven projects. In August 2008, FERC approved our proposal, effective September 1, 2008. The total cost for all eleven projects is estimated at $877 million, and all projects are currently expected to be completed by 2012.

PJM Capacity Auction Complaint

In May 2008, the Maryland Public Service Commission, Delaware Public Service Commission, Pennsylvania Commission, New Jersey Board of Public Utilities, the American Forest & Paper Association, the Portland Cement Association and several other organizations representing consumers in the PJM region (the RPM Buyers) filed a complaint at FERC claiming that PJM s Reliability Pricing Model s transitional auctions have produced unjust and unreasonable capacity prices. The RPM Buyers requested that a refund effective date of June 1, 2008 be established and that FERC provide appropriate relief from unjust and unreasonable capacity charges within 15 months. In September 2008, FERC dismissed the complaint.

RTO Start-up Costs and Administration Fees

In September 2008, we filed a Deferral Recovery Charge (DRC) request with FERC to recover approximately $153 million of RTO costs that we have been unable to recover due to a statutory rate cap established under Virginia law. The RTO costs include:

(i) costs incurred in development of Alliance RTO on and after this rate cap became effective on July 1, 1999;

(ii) costs incurred to start up our participation in PJM; and

(iii) PJM administrative fees billed by PJM from the date that we joined PJM as a transmission owner.

If the DRC is approved by FERC, then recovery of RTO costs through the DRC will not commence until the date established by the Virginia Commission permitting us to implement such recovery.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we are allowed to seek recovery through rates.

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Clean Air Act Compliance

In February 2008, the D.C. Appeals Court issued a ruling that vacates the Clean Air Mercury Rule (CAMR) as promulgated by the EPA. In May 2008, the EPA s appeal of this decision with the D.C. Appeals Court was denied. In September 2008, the Utility Air Regulatory Group filed a petition requesting that the U.S. Supreme Court overturn the D.C. Appeals Court decision to vacate the EPA rules. In October 2008, the Solicitor General, on behalf of the EPA, also filed a petition with the U.S. Supreme Court. We cannot predict how the EPA and the states that adopted CAMR-based mercury emissions reduction rules may alter their approach to reducing mercury emissions. Given this regulatory uncertainty, we cannot estimate at this time the impact of the ruling on our future capital and operational expenditures. It should be noted that we continue to be governed by individual state mercury emission reduction regulations in Massachusetts and Illinois that were largely unaffected by the CAMR ruling.

In July 2008, the D.C. Appeals Court issued a ruling that vacates the Clean Air Interstate Rule (CAIR) as promulgated by the EPA. The primary effects of the Court s decision are the elimination of the CAIR requirement to surrender sulfur dioxide (SO_2) allowances under the Acid Rain Program at a 2:1 ratio starting in 2010 and a 2.86:1 ratio starting in 2015, and the emission reduction targets and timetables for nitrogen oxides (NO_X) that were beyond those reductions already required under the Clean Air Act s Acid Rain Program. The CAIR annual NO_X emissions allowance cap and trade program is also eliminated. Remaining in effect is the EPA NO_X State Implementation Plan Call regulation applicable to summertime NO_X emissions under a cap and trade program and the Acid Rain Program for SO_2 reductions. A number of parties, including the EPA, filed petitions for a D.C. Appeals Court rehearing of the decision. The CAIR ruling remains deferred until the D.C. Appeals Court rules on the petitions for rehearing.

We do not expect to recognize any loss in connection with the elimination of the annual NO_X program as all of our annual NO_X allowances were allocated to us and were not assigned a cost value. The Court s decision has resulted in a decline in the market value of SO_2 allowances which may impact our ability to monetize the value of these allowances in the future. We tested our SO_2 allowances for impairment and concluded that no impairment adjustment was required for SO_2 allowances during the third quarter of 2008, as a result of this decline in market value.

Regulation of Greenhouse Gas Emissions

We operate two coal/oil-fired generating power stations in Massachusetts that are already subject to the implementation of carbon dioxide (CO_2) emission regulations issued by the Massachusetts Department of Environmental Protection (MADEP). Additionally, Massachusetts and Rhode Island have joined the Regional Greenhouse Gas Initiative (RGGI), a multi-state effort to reduce CO_2 emissions in the Northeast to be implemented through state specific regulations which are currently in development in these states. We own and operate a gas/oil-fired electric generating facility in Rhode Island that is subject to RGGI, in addition to the two coal/oil-fired stations in Massachusetts. The cost of complying with the RGGI requirements for the period 2009 to 2011 could adversely affect our results of operations. However, because of the price volatility that may occur in the early stages of this emerging market, we cannot provide a reasonable estimate of such cost until the RGGI CO_2 allowance market more fully matures. We participated in the first RGGI auction in September 2008. Any such costs of compliance could potentially be mitigated by increases in power prices impacting our affected facilities in the Northeast.

Clean Water Act Compliance

In July 2004, the EPA published regulations under the Clean Water Act Section 316b that govern existing utilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The EPA s rule presented several compliance options. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. In July 2007, the EPA suspended the regulations pending further rulemaking, consistent with the decision issued by the U.S. Court of Appeals for the Second Circuit. In November 2007, a number of industries appealed the lower court decision to the U.S. Supreme Court. In April 2008, the U.S. Supreme Court granted the industry request to review the question of whether Section 316b of the Clean Water Act authorizes EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral arguments before the U.S. Supreme Court are scheduled for December 2, 2008 with a decision expected in 2009. We have sixteen facilities that are likely to be subject to these regulations. We cannot predict the outcome of the judicial or EPA regulatory processes, nor can we determine with any certainty what specific controls may be required.

In August 2006, the Connecticut Department of Environmental Protection (CTDEP) issued a notice of a Tentative Determination to renew our Millstone power station s National Pollutant Discharge Elimination System (NPDES) permit, which included a draft copy of the revised permit. In October 2007, CTDEP issued a report to the hearing officer for the tentative determination stating the agency s intent to further revise the draft permit. In December

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2007, the CTDEP issued a new draft permit. An administrative hearing on the draft permit is scheduled to begin in January 2009, with a Final Determination expected to be issued by the CTDEP during 2009. Until the final permit is reissued, it is not possible to predict the financial impact that may result.

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ITEM 3. QUANTITATIVE AND QUALITATIVE

DISCLOSURES ABOUT MARKET RISK

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part I, Item 2. MD&A of this Form 10-Q. The reader s attention is directed to those paragraphs for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices. Commodity price risk is present in our electric operations, gas production and procurement operations, and energy marketing and trading operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. We use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to equity price risk through various portfolios of equity securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% unfavorable change in commodity prices and interest rates.

Commodity Price Risk

To manage price risk, we primarily hold commodity-based financial derivative instruments for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products. As part of our strategy to market energy and to manage related risks, we also hold commodity-based financial derivative instruments for trading purposes.

The derivatives used to manage our commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $325 million and $338 million as of September 30, 2008 and December 31, 2007, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $12 million and $8 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of September 30, 2008 and December 31, 2007, respectively.

The impact of a change in energy commodity prices on our non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from sales.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at September 30, 2008, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $10 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2007, would have resulted in a decrease in annual earnings of approximately $11 million.

Investment Price Risk

We are subject to investment price risk due to securities held as investments in nuclear decommissioning trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in our Consolidated Balance Sheets at fair value.

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Following the reapplication of SFAS No. 71, to the Virginia jurisdiction of our utility generation operations in April 2007, gains or losses on those nuclear decommissioning trust investments are recorded to regulatory liabilities.

We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $91 million for the nine months ended September 30, 2008 and net realized gains (including investment income) of $44 million and $43 million for the nine months ended September 30, 2007 and for the year ended December 31, 2007, respectively. For the nine months ended September 30, 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $259 million. For the nine months ended September 30, 2007, we recorded, in AOCI and regulatory liabilities, an increase in unrealized gains on these investments of $104 million. For the year ended December 31, 2007, we recorded, in AOCI and regulatory liabilities, an increase in unrealized gains on these investments of $52 million.

We sponsor employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. Declines in the values of investments held in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and the amount of cash to be contributed to the employee benefit plans.

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including our CEO and CFO, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, the CEO and CFO have concluded that our disclosure controls and procedures are effective.

There were no changes in our internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by us, or permits issued by various local, state and federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, we are involved in various legal proceedings. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations. See Future Issues and Other Matters in MD&A for discussions on various environmental and other regulatory proceedings to which we are a party.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that potentially violated Clean Air Act (CAA) permitting requirements. In July 2007, a third party purchased our E&P assets in Utah, including these facilities. In September 2008, we received a draft Consent Decree related to the potential CAA infractions, which imposes obligations on our subsidiary, DEPI and the purchaser, including payment of a civil penalty to the U.S. Department of Justice (DOJ) in the amount of $250,000. We expect the Consent Decree will be executed during the fourth quarter of 2008 after which it will be posted for public notice and comment for a period of not less than thirty days. Following the execution of the Consent Decree and the expiration of the 30-day public notice and comment period, the DOJ may request the federal judge in this proceeding to enter a final Consent Decree. Per our asset purchase agreement, the third-party purchaser assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2007 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008, which should be taken into consideration when reviewing the information contained in this report. There have been no material changes with regard to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2007 or our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The table below provides certain information with respect to our purchases of our common stock:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased[(1)]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs
7/1/08-7/31/08	1,991	$ 47.49	N/A	53,971,148 shares/ $2.68 billion
8/1/08-8/31/08	768	44.18	N/A	53,971,148 shares/ $2.68 billion
9/1/08-9/30/08	5,697	43.53	N/A	53,971,148 shares/ $2.68 billion
Total	8,456	$ 44.52	N/A	53,971,148 shares/

$2.68 billion

(1) Amount represents registered shares tendered by employees to satisfy tax withholding obligations on vested restricted stock.

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Item 6. EXHIBITS

(a) Exhibits:

3.1	Articles of Incorporation as in effect August 9, 1999, as amended March 12, 2001 (Exhibit 3.1, Form 10-K for the year ended December 31, 2002, File No. 1-8489, incorporated by reference), as amended November 9, 2007 (Exhibit 3, Form 8-K, filed November 9, 2007, File No. 1-8489, incorporated by reference).
3.2	Amended and Restated Bylaws effective on June 20, 2007 (Exhibit 3.1, Form 8-K filed June 22, 2007, File No. 1-8489, incorporated by reference).
4	Dominion Resources, Inc. agrees to furnish to the SEC upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of its total consolidated assets.
10.1	$500 million 364-Day Revolving Credit Agreement dated July 30, 2008 among Dominion Resources, Inc., The Royal Bank of Scotland PLC, as Administrative Agent, Barclays Bank PLC and Morgan Stanley Bank, as Co-Syndication Agents, Citibank N.A. and The Bank of Nova Scotia, as Co-Documentation Agents and other lenders named therein (filed herewith).
10.2	Form of Advancement of Expenses for certain directors and officers of Dominion, approved by the Board of Directors on October 24, 2008 (filed herewith).
10.3	New Executive Supplemental Retirement Plan, as amended and restated, effective January 1, 2009 (filed herewith).
10.4	New Retirement Benefit Restoration Plan, as amended and restated, effective January 1, 2009 (filed herewith).
12	Ratio of earnings to fixed charges (filed herewith).
31.1	Certification by Registrant s CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the SEC by Registrant s CEO and CFO, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99	Condensed consolidated earnings statements (unaudited) (filed herewith).

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DOMINION RESOURCES, INC.
Registrant

October 30, 2008

/s/ Thomas P. Wohlfarth
Thomas P. Wohlfarth
Senior Vice President and Chief Accounting Officer

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