DOMINION RESOURCES INC /VA/
Form 10-Q
November 01, 2007
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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, 2007

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 incorporation or organization)	*(I.R.S. Employer 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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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, 2007, the latest practicable date for determination, 287,724,069 shares of common stock, without par value, of the registrant were outstanding.

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DOMINION RESOURCES, INC.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(millions, except per share amounts)	2007	2006	2007	2006
Operating Revenue	**$ 3,589**	$ 3,973	**$ 11,980**	$ 12,375
Operating Expenses				
Electric fuel and energy purchases	**914**	1,057	**2,742**	2,580
Purchased electric capacity	**111**	122	**339**	361
Purchased gas	**346**	343	**2,024**	2,153
Other energy-related commodity purchases	**64**	144	**184**	862
Other operations and maintenance	**1,159**	502	**3,906**	2,123
Gain on sale of U.S. non-Appalachian E&P business	**(3,617)**		**(3,602)**	
Depreciation, depletion and amortization	**284**	389	**1,116**	1,146
Other taxes	**113**	122	**436**	430
Total operating expenses	**(626)**	2,679	**7,145**	9,655
Income from operations	**4,215**	1,294	**4,835**	2,720
Other income	**33**	43	**125**	134
Interest and related charges:				
Interest expense	**403**	218	**862**	658
Interest expense junior subordinated notes payable[1]	**30**	34	**100**	94
Subsidiary preferred dividends	**4**	4	**12**	12
Total interest and related charges	**437**	256	**974**	764
Income from continuing operations before income taxes, minority interest and extraordinary item	**3,811**	1,081	**3,986**	2,090
Income tax expense	**1,498**	421	**1,576**	750
Minority interest expense (income)	**(7)**	5	**7**	5
Income from continuing operations before extraordinary item	**2,320**	655	**2,403**	1,335
Extraordinary item[2]			**(158)**	
Income (loss) from discontinued operations[3]	**(3)**	(1)	**(5)**	14
Net Income	**$ 2,317**	$ 654	**$ 2,240**	$ 1,349
Earnings Per Common Share Basic[4]				
Income from continuing operations before extraordinary item	**$ 7.30**	$ 1.86	**$ 7.10**	$ 3.82
Extraordinary item			**(0.47)**	

Income (loss) from discontinued operations		**(0.01)**				**(0.01)**		0.04
Net income	**$**	**7.29**	$	1.86	**$**	**6.62**	$	3.86
Earnings Per Common Share Diluted[1]								
Income from continuing operations before extraordinary item	**$**	**7.25**	$	1.85	**$**	**7.05**	$	3.80
Extraordinary item						**(0.46)**		
Income (loss) from discontinued operations		**(0.01)**				**(0.01)**		0.04
Net income	**$**	**7.24**	$	1.85	**$**	**6.58**	$	3.84
Dividends paid per common share[4]	**$**	**0.71**	$	0.69	**$**	**2.13**	$	2.07

(1) Includes affiliated interest expense of $17 million and $29 million for the three months ended September 30, 2007 and 2006, respectively, and $61 million and $86 million for the nine months ended September 30, 2007 and 2006, respectively.

(2) Net of income tax benefit of $101 million.

(3) Includes income tax expense of $3 million and $116 million for the three and nine months ended September 30, 2007, respectively. Net of income tax benefit of $1 million for the three months ended September 30, 2006. Includes income tax benefit of $17 million for the nine months ended September 30, 2006.

(4) Per share figures do not reflect the effects of a two-for-one stock split approved by our board of directors on October 26, 2007. Dominion shareholders of record on November 9, 2007 will receive one additional share of common stock for each share held at the close of business on that date. See Note 10 for further details.

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, 2007	December 31, 2006[(1)]
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 469**	$ 138
Customer receivables (less allowance for doubtful accounts of $29 and $26)	**1,687**	2,395
Other receivables (less allowance for doubtful accounts of $13 and $13)	**256**	358
Inventories	**1,072**	1,101
Derivative assets	**1,244**	1,593
Assets held for sale	**1,096**	1,391
Prepayments	**115**	254
Other	**864**	868
Total current assets	**6,803**	8,098
Investments		
Nuclear decommissioning trust funds	**2,942**	2,791
Other	**1,051**	1,034
Total investments	**3,993**	3,825
Property, Plant and Equipment		
Property, plant and equipment	**32,915**	43,575
Accumulated depreciation, depletion and amortization	**(12,054)**	(14,193)
Total property, plant and equipment, net	**20,861**	29,382
Deferred Charges and Other Assets		
Goodwill	**3,496**	4,298
Pension and other postretirement benefit assets	**1,312**	1,246
Other	**2,061**	2,420
Total deferred charges and other assets	**6,869**	7,964
Total assets	**$ 38,526**	$ 49,269

(1) Our Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.
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, 2007	December 31, 2006[1]
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 799**	$ 2,478
Short-term debt		2,332
Accounts payable	**1,330**	2,142
Derivative liabilities	**1,787**	2,276
Liabilities held for sale	**414**	497
Accrued taxes	**3,075**	185
Other	**955**	1,319
Total current liabilities	**8,360**	11,229
Long-Term Debt		
Long-term debt	**11,002**	12,842
Junior subordinated notes payable:		
Affiliates	**678**	1,151
Other	**798**	798
Total long-term debt	**12,478**	14,791
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,097**	5,858
Asset retirement obligations	**1,715**	1,930
Regulatory liabilities	**1,190**	614
Other	**1,152**	1,654
Total deferred credits and other liabilities	**8,154**	10,056
Total liabilities	**28,992**	36,076
Commitments and Contingencies (see Note 19)		
Minority Interest	**29**	23
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par[2]	**5,694**	11,250
Other paid-in capital	**165**	128
Retained earnings	**3,438**	1,960
Accumulated other comprehensive loss	**(49)**	(425)
Total common shareholders equity	**9,248**	12,913

Total liabilities and shareholders equity	**$ 38,526**	$ 49,269

(1) Our Consolidated Balance Sheet at December 31, 2006 has been derived from the audited Consolidated Financial Statements at that date.

(2) 500 million shares authorized; 288 million shares outstanding at September 30, 2007 and 349 million shares outstanding at December 31, 2006.

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, (millions)	2007	2006
Operating Activities		
Net income	**$ 2,240**	$ 1,349
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of non-Appalachian E&P business	**(3,796)**	
Impairment of merchant generation assets	**387**	
Costs associated with early retirement of debt	**242**	
Extraordinary item, net of income taxes	**158**	
Charges related to termination of volumetric production payment agreements	**139**	
Dominion Capital, Inc. impairment losses	**86**	89
Charges related to pending sale of gas distribution subsidiaries		185
Net realized and unrealized derivative (gains) losses	**373**	(318)
Depreciation, depletion and amortization	**1,244**	1,296
Deferred income taxes and investment tax credits, net	**(1,670)**	417
Other adjustments to income, net	**10**	(87)
Changes in:		
Accounts receivable	**766**	1,042
Inventories	**(15)**	(143)
Deferred fuel and purchased gas costs, net	**(164)**	231
Accounts payable	**(631)**	(656)
Accrued taxes	**2,880**	249
Deferred revenues	**(71)**	(203)
Margin deposit assets and liabilities	**(79)**	(26)
Other operating assets and liabilities	**184**	61
Net cash provided by operating activities	**2,283**	3,486
Investing Activities		
Plant construction and other property additions	**(1,449)**	(1,365)
Additions to gas and oil properties, including acquisitions	**(1,788)**	(1,509)
Net proceeds from sale of merchant generation facilities	**339**	
Net proceeds from sale of non-Appalachian E&P business [(1)]	**13,706**	
Proceeds from sale of securities and loan receivable collections and payoffs	**968**	750
Purchases of securities and loan receivable originations	**(1,030)**	(808)
Other	**68**	152
Net cash provided by (used in) investing activities	**10,814**	(2,780)
Financing Activities		
Repayment of short-term debt, net	**(2,332)**	(1,386)
Issuance of long-term debt	**1,235**	1,800
Repayment of long-term debt, including redemption premiums	**(4,984)**	(835)
Repayment of affiliated notes payable	**(440)**	
Issuance of common stock	**193**	435
Repurchase of common stock	**(5,763)**	
Common dividend payments	**(704)**	(727)
Other	**27**	(11)
Net cash used in financing activities	**(12,768)**	(724)

Increase (decrease) in cash and cash equivalents		**329**		(18)
Cash and cash equivalents at beginning of period [2]		**142**		146
Cash and cash equivalents at end of period [3]	**$**	**471**	$	128
Noncash Investing and Financing Activities:				
Accrued capital expenditures	**$**	**56**	$	218
Proceeds held in escrow from sale of Canadian E&P operations		**156**		
Issuance of long-term debt and establishment of trust				47

(1) Excludes $156 million of proceeds held in escrow from the sale of our Canadian E&P operations.
(2) 2007 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.
(3) 2007 and 2006 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. (Dominion), headquartered in Richmond, Virginia, is one of the nation s largest producers and transporters of energy, with a portfolio of more than 26,500 megawatts (Mw) of generation, 7,800 miles of natural gas transmission pipeline and 1 trillion cubic feet equivalent (Tcfe) of natural gas and oil reserves. Dominion also owns and operates the nation s largest underground natural gas storage system with about 960 billion cubic feet (bcf) of storage capacity and serves retail energy customers in 11 states. On June 30, 2007, we merged our wholly-owned subsidiary, Consolidated Natural Gas Company (CNG), with our holding company, Dominion. As a result of the merger, all of CNG s subsidiaries became direct subsidiaries of Dominion.

As of September 30, 2007, we have sold all of our non-Appalachian natural gas and oil exploration and production (E&P) operations. We chose to retain our Appalachian assets due to their strategic fit with our natural gas transmission and storage assets. These transactions are discussed in Note 6.

Following the sale of our non-Appalachian E&P operations, our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Dominion Energy, Inc. (DEI), Dominion Transmission, Inc. (DTI) and Virginia Power Energy Marketing, Inc. (VPEM).

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, 2007, 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 Interconnection, LLC (PJM), a regional transmission organization (RTO), and its electric transmission facilities are integrated into the PJM wholesale electricity markets.

DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas exploration and production in the Appalachian basin of the United States (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 activities.

We have additional subsidiaries that operate in the natural gas business, including a variety of energy marketing services. As of September 30, 2007, our regulated gas distribution subsidiaries served approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and our nonregulated retail energy marketing businesses served approximately 1.6 million residential and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the U.S. 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 wholesale activities.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI) whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending. Refer to Note 16 for information on a third-party collateralized debt obligation (CDO) entity that we consolidate in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. In addition, we report a Corporate segment that includes our corporate, service company and other functions. Our assets remain wholly owned by us and our legal subsidiaries.

In the fourth quarter of 2007, we will realign our business units to reflect our strategic refocusing and begin managing our daily operations through three primary operating segments: Dominion Virginia Power (DVP), Dominion Generation and Dominion Energy. DVP will include our regulated electric distribution and electric transmission operations in

Virginia and North Carolina, as well as our nonregulated retail energy marketing and customer service operations. Dominion Generation will continue to include our regulated and merchant power generation. Dominion Energy will include our regulated natural gas distribution, transmission, storage and LNG operations, Appalachian-based natural gas and oil E&P operations and producer services.

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one 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 Securities and Exchange Commission (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 accounting principles generally accepted in the United States of America (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, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

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, 2007, our results of operations for the three and nine months ended September 30, 2007 and 2006, and our cash flows for the nine months ended September 30, 2007 and 2006.

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 and those variable interest entities (VIEs) where we have been determined to be the primary beneficiary.

In accordance with GAAP, we report certain contracts and instruments at fair value. Market pricing and indicative price information from external sources are used to measure fair value when available. In the absence of this information, we estimate fair value based on near-term and historical price information and statistical methods. For individual contracts, the use of differing assumptions could have a material effect on the contract s estimated fair value. See Note 2 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006 for a more detailed discussion of our estimation techniques.

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 2006 Consolidated Financial Statements and Notes have been recast to conform to the 2007 presentation.

As discussed further in Note 5, we reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to the Virginia jurisdiction of our utility generation operations upon enactment of reregulation legislation in Virginia on April 4, 2007. In connection with the reapplication of SFAS No. 71 to these operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities.

Under amendments to the Virginia fuel cost recovery statute passed in 2004, the fuel factor provisions for our electric utility were frozen until July 1, 2007. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were instituted beginning July 1, 2007.

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Note 3. Newly Adopted Accounting Standards
FIN 48

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $58 million charge to beginning retained earnings, representing the cumulative effect of the change in accounting principle.

Unrecognized tax benefits represent those tax benefits related to tax positions that have been taken or are expected to be taken in tax returns, including refund claims, that are not recognized in the financial statements because, in accordance with FIN 48, management has either measured the tax benefit at an amount less than the benefit claimed, or expected to be claimed, or concluded that it is not more-likely-than-not that the tax position will be ultimately sustained. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of an income tax refund receivable, an increase in deferred tax liabilities, or a decrease in deferred tax assets. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in other current liabilities, except when such amounts are presented net with amounts receivable from or amounts prepaid to taxing authorities in other current assets.

In May 2007, the FASB issued FASB Staff Position No. FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48* (FSP FIN 48-1), to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. In light of its delayed issuance, if an enterprise did not implement FIN 48 in a manner consistent with the provisions of FSP FIN 48-1, it is required to retrospectively apply its provisions to the date of its initial adoption of FIN 48. In our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, we reported that our unrecognized tax benefits totaled $642 million as of January 1, 2007. In accordance with FSP FIN 48-1, we have reduced our January 1, 2007 balance of unrecognized benefits to $625 million to adjust for effectively settled tax positions.

For the nine months ended September 30, 2007, the activity for unrecognized tax benefits for tax positions taken in prior years included gross increases of $60 million and reductions of $51 million due to settlements with taxing authorities. The activity for unrecognized tax benefits for tax positions taken in the current year included gross increases of $47 million and gross decreases of $26 million.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits also include amounts, for which uncertainty exists as to whether such amounts are deductible as ordinary deductions or capital losses. As discussed further in Note 6, we have sold all of our non-Appalachian E&P operations and assets. With the realization of gains from the non-Appalachian E&P sales, these prior year losses, if ultimately determined to be capital losses, would be deductible in 2007. When uncertainty about the deductibility of amounts is limited to the timing of such deductibility, any tax liabilities recognized for prior periods would be subject to offset with the availability of refundable amounts from later periods when such deductions could otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued from the due date of prior years returns until the period in which the amounts would be deductible, if not deducted in prior years. Through the nine months ended September 30, 2007, unrecognized tax benefits for prior periods have been reduced by $248 million to recognize amounts that, if not deducted in prior years, would be deductible in 2007. Over the next twelve months, unrecognized tax benefits could be reduced by an additional $16 million to recognize prior period amounts becoming otherwise deductible in the current period.

Unrecognized tax benefits as of January 1, 2007, included $76 million that, if recognized, would lower the effective tax rate. For the nine months ended September 30, 2007, the activity for such unrecognized tax benefits related to tax positions taken in the current year included gross decreases of $17 million and gross increases of $31 million.

Consistent with our existing policies, we continue to recognize estimated interest payable on underpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. As of January 1, 2007, we had accrued approximately $9 million for interest and penalties.

We file a consolidated U.S. federal income tax return for Dominion and its subsidiaries. In addition, where applicable, we file combined income tax returns for Dominion and its subsidiaries in various states; otherwise, we file separate income tax returns for our subsidiaries in various states. We also filed federal and provincial income tax returns for certain former subsidiaries in Canada.

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For Dominion and its subsidiaries, the U.S. federal statute of limitations has expired for tax years prior to 1999, except that we have reserved the right to claim certain 1998 tax credits and also have reserved the right to pursue a refund of amounts related to interest costs capitalized on plant and equipment during the years 1995 through 1998. For CNG and its former subsidiaries, tax years prior to Dominion s acquisition of CNG in January 2000 are no longer subject to examination, except for amended returns filed in June 2007 for tax years 1996, 1997 and 1998, claiming refunds for certain tax credits.

The U.S. Congressional Joint Committee on Taxation has recently completed its review of our settlement for tax years 1993 through 1998 with the Appellate Division of the Internal Revenue Service (IRS). As a result, we will receive a tax refund of approximately $42 million. Receipt of this refund will not impact our results of operations. We are also currently engaged in settlement negotiations with the Appellate Division of the IRS regarding certain adjustments proposed during the examination of tax years 1999 through 2001. Settlement negotiations could possibly conclude later this year. In addition, the IRS recently completed its examination of our 2002 and 2003 consolidated returns and the 2002 and 2003 returns of certain affiliate partnerships. We filed protests for certain proposed adjustments with the Appellate Division of the IRS in July and October 2007.

We have filed appeals of assessments received from taxing authorities, and we believe that it is reasonably possible that, based on settlement negotiations, unrecognized tax benefits could decrease by up to $77 million over the next twelve months.

For major states in which we operate, the earliest tax year remaining open for examination is as follows:

State	**Earliest Open Tax Year**
Pennsylvania	2000
Connecticut	2001
Virginia	2003
Massachusetts	2003

We are also obligated to report adjustments resulting from IRS settlements to state taxing authorities. In addition, if we utilize state net operating losses or tax credits generated in years for which the statute of limitations has expired, the determination of such amounts is subject to examination.

EITF 04-13

Prior to the sale of our non-Appalachian E&P business, we entered into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore and to facilitate gas transportation. In September 2005, the FASB ratified the Emerging Issues Task Force s (EITF) consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (EITF 04-13), that requires buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. We adopted the provisions of EITF 04-13 on April 1, 2006 for new arrangements entered into, and modifications or renewals of existing arrangements after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for the three months and nine months ended September 30, 2007; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are included in the activity summarized below:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(millions)	**2007**	**2006**	**2007**	**2006**
Sale activity included in operating revenue	**$ 8**	$ 37	**$ 67**	$ 543
Purchase activity included in operating expenses[(1)]	**8**	39	**70**	539

(1) Included in other energy-related commodity purchases expense and purchased gas expense on our Consolidated Statements of Income.

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EITF 06-3

Effective January 1, 2007, EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*, requires certain disclosures if an entity collects any tax assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between the entity, as a seller, and its customers. We collect sales, consumption and consumer utility taxes but exclude such amounts from revenue.

Note 4. Recently Issued Accounting Standards
SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be 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 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*. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). 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. The provisions of SFAS No. 159 will become effective for us beginning January 1, 2008. We are currently evaluating the impact that SFAS No. 159 may have on our results of operations and financial condition.

EITF 06-4

In September 2006, the FASB ratified the consensus reached by the EITF on Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* (EITF 06-4). 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 Accounting Principles Board 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. We have certain insurance policies subject to the provisions of EITF 06-4 and are currently evaluating the impact that EITF 06-4 may have on our results of operations and financial condition. The provisions of EITF 06-4 will become effective for us beginning January 1, 2008.

EITF 06-11

In June 2007, the FASB ratified the consensus reached by the EITF on Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11). 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 equity-classified share-based payment awards. Effective January 1, 2008, we will recognize such income tax benefits as an increase to additional paid-in capital rather than as a reduction to income tax expense. We do not expect EITF 06-11 to have a material impact on our results of operations or financial condition.

FSP FIN 39-1

In April 2007, the FASB issued FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts* (FSP FIN 39-1). 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. FSP FIN 39-1 will become effective for us beginning January 1, 2008 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. We are currently evaluating the impact that FSP FIN 39-1 may have on our financial condition. We do not expect FSP FIN 39-1 to have an impact on our results of operations or cash flows.

Note 5. Reapplication of SFAS No. 71

In March 1999, we discontinued the application of SFAS No. 71 to the majority of our utility generation operations upon the enactment of deregulation legislation in Virginia. Our utility transmission and distribution operations continued to apply the provisions of SFAS No. 71 since they remained subject to cost-of-service rate regulation.

In April 2007, the Virginia General Assembly passed legislation that returns the Virginia jurisdiction of our utility generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. The accounting impacts of the reapplication of SFAS No. 71 are described below.

Extraordinary Item

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations 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 accumulated other comprehensive income (AOCI). This was done in order to establish a $454 million long-term regulatory liability for amounts 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* (SFAS No. 143).

Pension and Other Postretirement Benefits

Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, we reclassified $110 million ($67 million after tax) of pension and other postretirement benefit costs attributable to those operations previously recorded in AOCI to a regulatory asset. These costs represent net unrecognized actuarial (gains) losses, unrecognized prior service cost (credit) and unrecognized transition obligation remaining from our initial adoption of SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*, that will be recognized as a component of future net periodic benefit cost based on our historical accounting policy for amortizing such amounts and are expected to be recovered through future rates.

Accounting Policy Changes

In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our utility generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed above, the overall impact of these changes, summarized below, was not material to our results of operations or financial condition.

Utility Nuclear Decommissioning Trust Funds

Net realized and unrealized gains and losses are now recorded to the regulatory liability established upon reapplication of SFAS No. 71 as described above. Previously, realized gains and losses and any other-than-temporary declines in fair value were included in other income and unrealized gains were reported as a component of AOCI, net of tax.

Property, Plant and Equipment

Early retirements of generation-related utility property are now recorded to accumulated depreciation rather than recognizing gains and losses upon retirement. Cost of removal incurred or salvage proceeds realized in connection with a retirement of utility generation property, plant and equipment is now recorded to accumulated depreciation rather than being charged to expense as incurred. We discontinued capitalizing interest on all utility generation construction projects since the Virginia State Corporation Commission (Virginia Commission) previously allowed for current recovery of construction financing costs.

Asset Retirement Obligations (ARO)

Accretion and depreciation associated with utility nuclear decommissioning AROs, previously charged to expense, are now recorded as a reduction to the regulatory liability for nuclear decommissioning trust funds discussed above, in order to match the recognition for rate-making purposes.

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Derivative Instruments

Previously, unrealized gains and losses resulting from changes in the fair value of derivative instruments designated as cash flow or fair value hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), were recorded in AOCI, or long-term debt, respectively. Also, ineffectiveness and gains and losses excluded from the measurement of ineffectiveness, were recorded through earnings as incurred. Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of these derivative instruments will be classified as regulatory assets or regulatory liabilities as these instruments now receive regulatory treatment. Gains or losses on the derivative instruments will generally be recognized when the related transactions impact net income.

Note 6. Dispositions
Sale of Non-Appalachian Natural Gas and Oil E&P Operations and Assets

We have completed the sale of our non-Appalachian natural gas and oil E&P operations and assets for approximately $13.9 billion. At December 31, 2006, our non-Appalachian natural gas and oil assets included about 5.5 Tcfe of proved reserves. The Appalachian assets that we have retained included about 1 Tcfe of proved reserves at December 31, 2006.

Due to the sale of our entire Canadian cost pool, the results of operations for our Canadian E&P business are reported as discontinued operations in our Consolidated Statements of Income. The results of operations for our U.S. non-Appalachian E&P business are 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.

We used most of the after-tax proceeds from these dispositions to reduce our outstanding debt and repurchase shares of our common stock. See Note 17 for a discussion of significant financing transactions.

The E&P operations we have sold are as follows:

Canadian Operations

On June 26, 2007, we completed the sale of our Canadian E&P operations to Paramount Energy Trust and Baytex Energy Trust for approximately $624 million, subject to post-closing adjustments. These operations included approximately 267 billion cubic feet equivalent (bcfe) of proved reserves in western Canada as of December 31, 2006. The sale resulted in an after-tax gain of $61 million ($0.17 per share). As required by the sale agreement, $156 million of the proceeds were held in escrow to ensure the payment of our Canadian tax obligation, resulting from the gain recognized on the sale. The funds were released from escrow in the fourth quarter of 2007 in exchange for a letter of credit. We expect to pay the tax related to the gain on the sale by the end of the second quarter of 2008.

The following table presents selected information regarding the results of operations of our Canadian E&P operations, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	**2007**	**2006**	**2007**	**2006**
Operating revenue	**$**	$ 33	**$ 82**	$ 109
Income before income taxes		3	**149**(1)	18

(1) Amount includes pre-tax gain of $194 million recognized on the sale.

Offshore Operations

On July 2, 2007, we completed the sale of substantially all of our offshore E&P operations to Eni Petroleum Co. Inc. (Eni) for approximately $4.73 billion, subject to post-closing adjustments. Our offshore operations included approximately 967 bcfe of proved natural gas and oil reserves in the outer continental shelf and deepwater areas of the Gulf of Mexico at December 31, 2006. Of this total, approximately 961 bcfe were sold to Eni. Remaining offshore E&P operations were disposed of in a separate transaction in June 2007.

Certain Onshore Operations

On July 31, 2007, we completed the sale to HighMount Exploration & Production LLC, a newly formed subsidiary of Loews Corporation, of our E&P operations in the Alabama, Michigan and Permian basins for approximately $4.0 billion, subject to post-closing adjustments. These operations included approximately 2.5 Tcfe of proved natural gas and oil reserves at December 31, 2006.

Also on July 31, 2007, we completed the sale to XTO Energy Inc., of our E&P operations in the Gulf Coast, Rocky Mountains, South Louisiana and San Juan Basin of New Mexico for approximately $2.5 billion, subject to post-closing adjustments. These operations included approximately 1 Tcfe of proved natural gas and oil reserves at December 31, 2006.

On August 31, 2007, we completed the sale to Linn Energy, LLC, of our E&P operations in the Mid-Continent Basin for approximately $2.0 billion, subject to post-closing adjustments. These operations, located primarily in Oklahoma, included approximately 780 bcfe of proved natural gas and oil reserves at December 31, 2006.

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

The sales 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 will 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 retained these gas and oil derivatives, but have entered into offsetting derivative contracts that will minimize the future volatility in earnings that may result from these contracts being marked to market. 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 volumetric production payment (VPP) agreements to which we were a party. We paid $250 million to terminate the VPP agreements and are retaining 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.

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 is 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. We expect to pay the federal income taxes related to the gain on the sale in the fourth quarter of 2007 and the related state income taxes by the end of the second quarter of 2008.

The total impact on net income from the sale of our Canadian and U.S. non-Appalachian E&P operations was $1.9 billion and $1.5 billion, respectively, for the three and nine months ended September 30, 2007. This benefit is 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, as discussed in Note 17.

Disposition of Partially Completed Generation Facility

In September 2007, we completed the sale of the 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.

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Sale of Certain DCI Operations

In May 2007, we committed to a plan to dispose of certain DCI operations for $30 million. The sale includes substantially all of the assets of Gichner LLC (Gichner), all of the issued and outstanding shares of the capital stock of Gichner, Inc. (an affiliate of Gichner), as well as all of the membership interests in Dallastown Realty (Dallastown). Gichner designs, manufactures, integrates, markets, distributes, sells and services tactical and logistic shelters and related products for military commercial applications. Dallastown owns the land and buildings in which Gichner conducts its principal operations in the U.S.

The consideration to be received indicated that the goodwill associated with these operations was impaired and in June 2007, we recorded a goodwill impairment charge in other operations and maintenance expense in our Consolidated Statement of Income of $8 million related to the DCI reporting unit. In August 2007, we completed the sale of Gichner and Dallastown for approximately $30 million. The sale resulted in an after-tax loss of $4 million ($0.01 per share), which included the allocation of $10 million of Corporate reporting unit goodwill to the bases of the investments sold.

The following table presents selected information regarding the results of operations of Gichner and Dallastown, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	**2007**	**2006**	**2007**	**2006**
Operating revenue	**$ 7**	$ 9	**$ 29**	$ 31
Income (loss) before income taxes	**(1)**		**(7)**	2

Sale of Merchant Generation Facilities

In March 2007, we sold three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) for net cash proceeds of $254 million. The sale resulted in a $24 million after-tax loss ($0.07 per share). The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary s, West Virginia.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet at December 31, 2006 were comprised of property, plant and equipment, net ($245 million), inventory ($13 million) and accounts payable ($3 million).

The following table presents selected information regarding the results of operations of the Peaker facilities, which are reported as discontinued operations in our Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	**2007**	**2006**	**2007**	**2006**

Operating revenue	**$**	$ 19	**$ 5**	$ 33
Loss before income taxes		(6)	**(31)** [1]	(23)

[1] Amount includes pre-tax loss of $25 million recognized on the sale, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments sold.

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Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc., to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope), for approximately $970 million plus adjustments to reflect capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is subject to regulatory approval, as discussed in *Future Issues and Other Matters* in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations. The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheets are as follows:

(millions)	September 30, 2007	December 31, 2006
ASSETS		
Current Assets		
Customer receivables	**$ 69**	$ 144
Other	**137**	125
Total current assets	**206**	269
Property, Plant and Equipment		
Property, plant and equipment	**1,150**	1,129
Accumulated depreciation, depletion and amortization	**(370)**	(375)
Total property, plant and equipment, net	**780**	754
Deferred Charges and Other Assets		
Regulatory assets	**108**	106
Other	**2**	4
Total deferred charges and other assets	**110**	110
Assets held for sale	**$ 1,096**	$ 1,133
LIABILITIES		
Current Liabilities	**$ 151**	$ 236
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**190**	187
Other	**73**	71
Total deferred credits and other liabilities	**263**	258
Liabilities held for sale	**$ 414**	$ 494

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

(millions)	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006

Operating revenue	**$ 62**	$ 63	**$ 479**	$ 512
Income (loss) before income taxes	**(6)**	(6)	**49**	(134)

In the nine months ended September 30, 2006, we recognized a $167 million ($103 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, since the recovery of those assets is no longer probable. At September 30, 2007, our Consolidated Balance Sheet reflects $134 million of deferred tax liabilities, which were recorded 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* (EITF 93-17). 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. We recorded these deferred tax liabilities, since the financial reporting basis of our investment in Peoples and Hope exceeded our tax basis. This difference and related deferred taxes will reverse and will partially offset current tax expense recognized upon closing of the sale.

Note 7. Pro Forma Financial Statements

The accompanying unaudited Pro Forma Condensed Consolidated Statements of Income for the nine months ended September 30, 2007 and for the year ended December 31, 2006, reflect the disposition of our non-Appalachian E&P operations as if it had occurred on January 1, 2007 and 2006, respectively.

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The pro forma adjustments have been based on the operations of our non-Appalachian E&P operations during the periods presented, the impact of the disposition of these operations and other transactions resulting from the disposition. The pro forma adjustments have been made to illustrate the anticipated financial impact of the disposition upon Dominion and are based upon available information and assumptions that we believe to be reasonable at the date of this filing. Consequently, the pro forma financial information presented is not necessarily indicative of the consolidated results of operations that would have been reported had the transaction actually occurred on the dates presented. Moreover, the pro forma financial information does not purport to indicate the future results that Dominion will experience.

PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Nine Months Ended September 30, 2007

(Unaudited)

(millions, except per share amounts)	As Reported	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
Operating Revenue	$ 11,980	$ 1,351	$	$ 10,629
Operating Expenses				
Electric fuel and energy purchases	2,742			2,742
Purchased electric capacity	339			339
Purchased gas	2,024	50		1,974
Other energy-related commodity purchases	184			184
Other operations and maintenance	3,906	1,312	(8)(1)	2,586
Gain on sale of U.S. non-Appalachian E&P business	(3,602)	(3,602)		
Depreciation, depletion and amortization	1,116	427		689
Other taxes	436	87		349
Total operating expenses	7,145	(1,726)	(8)	8,863
Income from operations	4,835	3,077	8	1,766
Other income	125			125
Interest and related charges	974		(153)(2)	
			(234)(1)	587
Income from continuing operations before income tax expense and minority interest	3,986	3,077	395	1,304
Income tax expense	1,576	1,481	153 (3)	248
Minority interest	7			7
Income from continuing operations	$ 2,403	$ 1,596	$ 242	$ 1,049
Earnings Per Share				
Income from continuing operations Basic	$ 7.10			$ 3.61
Income from continuing operations Diluted	$ 7.05			$ 3.58
Weighted average shares outstanding Basic	338.4		(47.9)(4)	290.5
Weighted average shares outstanding Diluted	340.6		(47.9)(4)	292.7

(1) Represents the removal of non-recurring expenses associated with the completion of our debt tender offer on July 12, 2007, using a portion of the proceeds from the disposition of our non-Appalachian E&P operations.

(2) Represents the prorated decrease in interest expense resulting from the repayment of $3.4 billion in debt with a portion of the proceeds from the disposition of our non-Appalachian E&P operations (disposition). This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our and CNG s subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of trust preferred securities originally issued by CNG, which were redeemed on July 17, 2007.

(3) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted-average statutory rates for all jurisdictions that would have applied during the period.

(4) Reflects the prorated impact of our equity tender offer discussed in Note 17. We purchased approximately 57.8 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

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PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31, 2006

(Unaudited)

(millions, except per share amounts)	As Reported[1]	Less: E&P Dispositions	Pro Forma Adjustments	Pro Forma Results
Operating Revenue	$ 16,296	$ 2,838	$	$ 13,458
Operating Expenses				
Electric fuel and energy purchases	3,236			3,236
Purchased electric capacity	481			481
Purchased gas	2,937	165		2,772
Other energy-related commodity purchases	1,022	409		613
Other operations and maintenance	3,177	352		2,825
Depreciation, depletion and amortization	1,557	695		862
Other taxes	568	125		443
Total operating expenses	12,978	1,746		11,232
Income from operations	3,318	1,092		2,226
Other income	173			173
Interest and related charges	1,028		(254)[2]	774
Income from continuing operations before income tax expense and minority interest	2,463	1,092	254	1,625
Income tax expense	927	417	99 [3]	609
Minority interest	6			6
Income from continuing operations	$ 1,530	$ 675	$ 155	$ 1,010
Earnings Per Share				
Income from continuing operations Basic	$ 4.38			$ 3.46
Income from continuing operations Diluted	$ 4.35			$ 3.44
Weighted average shares outstanding Basic	349.7		(57.8)[4]	291.9
Weighted average shares outstanding Diluted	351.6		(57.8)[4]	293.8

(1) Reflects the reclassification of Gichner, Dallastown and our Canadian E&P operations to discontinued operations.

(2) Represents the decrease in interest expense expected to result from the repayment of $3.4 billion in debt with a portion of the proceeds from the disposition of our non-Appalachian E&P operations. This amount is comprised of $2.5 billion in long term debt retired in connection with our debt tender offer completed on July 12, 2007; $500 million of bank debt incurred at our CNG subsidiary which was repaid prior to the merger of that subsidiary with and into Dominion, effective June 30, 2007; $200 million of senior notes originally issued by our and CNG s subsidiary Dominion Oklahoma Texas Exploration & Production, Inc., which were redeemed on June 29, 2007 and $200 million of trust preferred securities originally issued by CNG, which were redeemed on July 17, 2007.

(3) Reflects the income tax effects of the pro forma adjustments associated with the disposition of our non-Appalachian E&P operations based on the weighted-average statutory rates for all jurisdictions that would have applied during the period.

(4) Reflects the final results of our equity tender offer discussed in Note 17. We purchased approximately 57.8 million shares at a price of $91 per share, with a portion of the proceeds received from the disposition.

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NOTES TO CONDENSED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Nonrecurring items related to the dispositions

Certain nonrecurring items resulting from the disposition of our non-Appalachian E&P operations have not been reflected in the accompanying Condensed Pro Forma Consolidated Statements of Income. See *Costs Associated with Disposal of Non-Appalachian E&P Operations* in Note 6.

Note 8. Operating Revenue
Our operating revenue consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2007	2006	2007	2006
Operating Revenue				
Electric sales:				
Regulated	**$ 1,796**	$ 1,650	**$ 4,593**	$ 4,231
Nonregulated	**839**	623	**2,299**	1,760
Gas sales:				
Regulated	**86**	96	**829**	1,071
Nonregulated	**338**	382	**1,681**	1,638
Other energy-related commodity sales	**128**	253	**434**	1,156
Gas transportation and storage	**181**	190	**742**	676
Gas and oil production	**147**	446	**1,191**	1,401
Other	**74**	333	**211**	442
Total operating revenue	**$ 3,589**	$ 3,973	**$ 11,980**	$ 12,375

Note 9. 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,	
	2007	2006
U.S. statutory rate	**35.0%**	35.0%
Increases (reductions) resulting from:		
Amortization of investment tax credits	**(0.2)**	(0.4)
Qualified production activities	**(0.5)**	
Employee pension and other benefits	**(0.2)**	(0.3)
Employee stock ownership plan and restricted stock dividends	**(0.3)**	(0.5)
State taxes, net of federal benefit	**3.4**	5.1
Changes in valuation allowances	**(2.6)**	(9.1)
Goodwill	**5.2**	

Recognition of deferred taxes stock of subsidiaries held for sale	**(0.2)**	6.5
Other, net	**(0.1)**	(0.4)
Effective tax rate	**39.5%**	35.9%

Our estimated 2007 annual effective tax rate reflects the effects of the sale of our non-Appalachian E&P operations, including the impact of goodwill, not deductible for tax purposes, that reduced the book gain on sale. A tax benefit has been recognized from the elimination of $126 million of valuation allowances on deferred tax assets that relate to federal and state loss carryforwards, since these carryforwards will be utilized to offset gains from the sale. As the result of changes in state apportionment following the sale, our future effective state tax rate is expected to be higher for ongoing operations.

In 2006, the effective tax rate reflected the net tax benefit from changes in valuation allowances on deferred tax assets, including a $222 million reduction related to federal and state tax loss carryforwards then expected to be utilized to offset capital gain income anticipated from the pending sale of Peoples and Hope, offset by a $38 million increase in the second quarter related to the impairment of certain DCI investments. The net benefit was partially offset by the establishment of $136 million of deferred tax liabilities, in 2006, associated with the excess of our financial reporting basis over our tax basis in the stock of Peoples and Hope, in accordance with EITF 93-17.

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Note 10. 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,	
(millions, except EPS)	2007	2006	2007	2006
Income from continuing operations before extraordinary item	**$ 2,320**	$ 655	**$ 2,403**	$ 1,335
Extraordinary item			**(158)**	
Income (loss) from discontinued operations	**(3)**	(1)	**(5)**	14
Net income	**$ 2,317**	$ 654	**$ 2,240**	$ 1,349
Basic EPS				
Average shares of common stock outstanding basic	**317.8**	351.9	**338.4**	349.1
Income from continuing operations before extraordinary item	**$ 7.30**	$ 1.86	**$ 7.10**	$ 3.82
Extraordinary item			**(0.47)**	
Income (loss) from discontinued operations	**(0.01)**		**(0.01)**	0.04
Net income	**$ 7.29**	$ 1.86	**$ 6.62**	$ 3.86
Diluted EPS				
Average shares of common stock outstanding	**317.8**	351.9	**338.4**	349.1
Net effect of potentially dilutive securities(1)	**2.0**	2.0	**2.2**	1.8
Average shares of common stock outstanding diluted	**319.8**	353.9	**340.6**	350.9
Income from continuing operations before extraordinary item	**$ 7.25**	$ 1.85	**$ 7.05**	$ 3.80
Extraordinary item			**(0.46)**	
Income (loss) from discontinued operations	**(0.01)**		**(0.01)**	0.04
Net income	**$ 7.24**	$ 1.85	**$ 6.58**	$ 3.84

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities and contingently convertible senior notes. Potentially dilutive securities with the right to acquire approximately 1 million common shares for the nine months ended September 30, 2006 were not included in the respective period s calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of our common shares. There were no such anti-dilutive securities outstanding during the three months ended September 30, 2006 or the three or nine months ended September 30, 2007.

Common Stock Split

On October 26, 2007, our board of directors approved a two-for-one stock split and an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion. Shareholders of record on November 9, 2007, will receive one additional share of common stock for each share held at the close of business on that date; however, the proportionate interest that a shareholder owns in the Company will not change as a result of the stock split. The additional shares will be distributed on or after November 19, 2007. Based on shares outstanding at September 30, 2007, upon the completion of the stock split Dominion will have approximately 575 million shares of common stock outstanding. The stock split will require us to recast all of our historical shares and per share data in the fourth quarter of 2007.

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Note 11. Goodwill

The changes in the carrying amount of goodwill during the nine months ended September 30, 2007 are presented below:

(millions)	Dominion Generation	Dominion Energy	Dominion Delivery	Dominion E&P	Corporate	Total
Balance at December 31, 2006	$ 1,479	$ 740	$ 1,184	$ 877	$ 18	$ 4,298
Sale of non-Appalachian E&P business				**(760)**		**(760)**
Sale of Peaker facilities	**(24)**					**(24)**
Sale of Gichner and Dallastown					**(18)**	**(18)**
Balance at September 30, 2007	**$ 1,455**	**$ 740**	**$ 1,184**	**$ 117**	**$**	**$ 3,496**

Note 12. Comprehensive Income

The following table presents total comprehensive income:

(millions)	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Net income	**$ 2,317**	$ 654	**$ 2,240**	$ 1,349
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	**104**	888 (1)	**428** (2)	2,011 (1)
Other	**18** (3)	70 (4)	**(52)** (5)	59 (4)
Other comprehensive income	**122**	958	**376**	2,070
Total comprehensive income	**$ 2,439**	$ 1,612	**$ 2,616**	$ 3,419

(1) Largely due to the settlement of certain commodity derivative contracts and favorable changes in fair value, primarily resulting from a decrease in electricity and gas prices.

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

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

(4) Primarily represents the impact of net unrealized gains on investments held in nuclear decommissioning trusts and foreign currency translation adjustments.

(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 unrealized gains on investments held in nuclear decommissioning trusts, both associated with the Virginia jurisdiction of our utility generation operations, previously recorded in AOCI to regulatory assets and regulatory liabilities, respectively, as a result of the reapplication of SFAS No. 71 to those operations.

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Note 13. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of electricity, natural gas, oil 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. Selected information about our hedge accounting activities follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2007	2006	2007	2006
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:				
Fair value hedges	**$ 3**	$ (15)	**$ 5**	$ (23)
Cash flow hedges	**4**	9	**47**	33
Net ineffectiveness	**$ 7**	$ (6)	**$ 52**	$ 10

For the three months and nine months ended September 30, 2007 and 2006, amounts excluded from the measurement of effectiveness did not have a significant impact on net income.

See Note 6 for a discussion of the discontinuance of hedge accounting for gas and oil hedges during the nine months ended September 30, 2007.

In the third quarter of 2007, we determined that, 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), this agreement no longer qualifies for the normal purchase and normal sale exception allowed under SFAS No. 133. As part of the termination transaction, we will pay approximately $233 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. The normal purchase and normal sale exception must be discontinued if it is no longer probable that physical delivery of power will continue to occur throughout the term of the power sales agreement. As a result of the discontinuance of the normal purchase and normal sale exception, we recorded a $236 million ($140 million after-tax) charge included in other operations and maintenance expense in our Consolidated Statement of Income. The transaction closed in October 2007.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at September 30, 2007:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ 19	$ 6	41 months
Electricity	12	6	65 months
Other	(2)	(4)	32 months
Interest rate	(27)	(4)	225 months
Foreign currency	4	2	44 months
Total	$ 6	$ 6	

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.

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Note 14. 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, assuming period-end hedge-adjusted prices.

Approximately 7% of the anticipated production from our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements 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, 2007.

Note 15. Asset Retirement Obligations

The following table describes the changes to our AROs during the nine months ended September 30, 2007:

(millions)	Amount
Asset retirement obligations at December 31, 2006[1]	$ 1,932
Obligations incurred during the period	**17**
Obligations settled during the period	**(30)**
Obligations relieved due to sale of non-Appalachian E&P business	**(275)**
Accretion	**74**
Revisions in estimated cash flows	**(2)**
Asset retirement obligations at September 30, 2007[1]	**$ 1,716**

(1) Includes $2 million and $1 million reported in other current liabilities at December 31, 2006 and September 30, 2007, respectively.

Note 16. Variable Interest Entities

Certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered potential variable interests in the counterparties. As discussed in Note 16 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, two potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), had not provided sufficient information for us to perform our evaluation under FIN 46R.

As of September 30, 2007, limited information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.2 billion at September 30, 2007. We are not subject to any risk of loss from these potential VIEs, other than the remaining purchase commitments. We paid $24 million for electric generation capacity from these entities in the three months ended September 30, 2007 and 2006. We paid $34 million and $31 million for electric energy from these entities in the three months ended September 30, 2007 and 2006, respectively. We paid $74 million and $72 million for electric generation capacity and $84 million and $68 million for electric energy from these entities in the nine months ended September 30, 2007 and 2006, respectively.

In 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at September 30, 2007. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $27 million and $29 million for electric generation capacity and $16 million and $14 million for electric energy from these entities in the three months ended September 30, 2007 and 2006, respectively. We paid $86 million and $87 million for electric generation capacity and $44 million and $42 million for electric energy from these entities in the nine months ended September 30, 2007 and 2006, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $120 million and $36 million to the LLCs

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for coal and synthetic fuel produced from coal in the three months ended September 30, 2007 and 2006, respectively, and $333 million and $243 million to the LLCs for coal and synthetic fuel produced from coal in the nine months ended September 30, 2007 and 2006, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts. These contracts will terminate on December 31, 2007.

Our Consolidated Balance Sheet as of December 31, 2006, reflected net property, plant and equipment of $337 million and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we had financed and leased a power generation plant for our utility operations. The debt was non-recourse to us and was secured by the entity s property, plant and equipment. The lease under which we operated the power generation facility terminated in August 2007 and we took legal title to the facility through the repayment of the lessor s related debt.

As discussed in Note 27 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, 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 that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. At September 30, 2007, the CDO entity had $420 million of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that serve as collateral for its obligations at September 30, 2007:

(millions)	**Amount**
Other current assets	$ 199
Loans held for sale	394
Other investments	33
Total assets	$ 626

Dominion reports loans held for sale at the lower of cost or market (LOCOM). We determine any LOCOM adjustment to the loans held for sale on a pool basis by aggregating those loans based on similar risks and characteristics. The fair value of the loans are calculated by discounting scheduled cash flows through the estimated maturity using estimated market discount rates that reflect the credit and interest rate risk inherent in the loan, current economic conditions, and lending conditions. The estimates of maturity are based on historical experience with repayments for each loan classification. During the third quarter of 2007, the fair value of the loans was determined to be less than the cost of the loans and we recognized an impairment loss on the loans of $54 million ($35 million after-tax).

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Note 17. Significant Financing Transactions

Credit Facilities and Short-Term Debt

As a result of the merger of CNG with Dominion, all of CNG s former credit facilities have been assumed by Dominion. 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 borrowing 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 the credit quality of our companies and their counterparties. At September 30, 2007, we had committed lines of credit totaling $4.9 billion. These lines of credit support commercial paper borrowings and letter of credit issuances. At September 30, 2007, we had the following commercial paper and letters of credit outstanding and capacity available under credit facilities:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
Five-year joint revolving credit facility[1]	$ 3,000	$	$ 155	$ 2,845
Five-year Dominion credit facility[2]	1,700		247	1,453
Five-year Dominion bilateral facility[3]	200			200
Totals	$ 4,900	$	$ 402	$ 4,498

(1) The $3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can also be used to support up to $1.5 billion of letters of credit.

(2) The $1.7 billion five-year credit facility is used to support the issuance of letters of credit and commercial paper. The facility was entered into in February 2006 and terminates in August 2010.

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

In addition to the facilities above, we also entered into a $100 million bilateral credit facility in August 2004 that terminates in August 2009. At September 30, 2007, there were no letters of credit outstanding under this facility.

Long-Term Debt

In May 2007, Virginia Power issued $600 million of 6.0% senior notes that mature in 2037. In September 2007, Virginia Power issued $600 million of 5.95% senior notes that mature in 2017. The proceeds were used for general corporate purposes, including the repayment of short-term debt.

We repaid $5.4 billion of long-term debt and notes payable during the nine months ended September 30, 2007, which includes the completion of a debt tender offer repurchasing $2.5 billion of our debt securities in July 2007. We recognized charges of $242 million ($148 million after-tax) primarily in connection with the early redemption of this debt. Of this amount, $234 million ($143 million after-tax) was recorded in interest and related charges in our Consolidated Statement of Income.

Included in the debt repayments above is the redemption of all 8 million units of the $200 million 7.8% Dominion CNG Capital Trust I debentures due October 31, 2041. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions. Also included is the redemption of approximately 240 thousand units of the $250 million 8.4% Dominion Capital Trust III debentures due January 15, 2031. These securities were redeemed at a price of $1,000 per preferred security plus accrued and unpaid distributions.

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. At September 30, 2007, since none of these conditions had been met, these senior notes are not yet subject to conversion. 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. At issuance, the notes were valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represented a conversion price of $73.60. 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, 2007, the conversion rate has been adjusted to 13.7425 primarily due to individual dividend payments above the level paid at issuance.

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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 of $73.60 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.

Issuance of Common Stock

During the nine months ended September 30, 2007, we issued 3.2 million shares and received cash proceeds of $193 million, in connection with the exercise of employee stock options.

Repurchases of Common Stock

During the nine months ended September 30, 2007, we repurchased 64.5 million shares of common stock for approximately $5.8 billion. This amount includes the completion of our equity tender offer in August 2007, in which we purchased approximately 57.8 million shares at a price of $91 per share for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

At September 30, 2007, our remaining repurchase authorization is the lesser of 27.0 million shares or $2.7 billion of our outstanding common stock.

Note 18. Stock-Based Awards

In April 2005, our shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). The 2005 Incentive Plan permits stock-based awards that include restricted stock, performance grants, goal-based stock and stock options and the Non-Employee Directors Plan permits restricted stock and stock options. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the Compensation, Governance and Nominating (CGN) Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years in length.

Our results for the three months ended September 30, 2007 and 2006 include $14 million and $8 million, respectively, of compensation costs and $5 million and $3 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Our results for the nine months ended September 30, 2007 and 2006 include $38 million and $23 million, respectively, of compensation costs and $14 million and $9 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.

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, 2007:

	Shares (thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (years)	Aggregated intrinsic value[1] (millions)
Outstanding and exercisable at January 1, 2007	7,246	$ 60.51		
Exercised	**(3,167)**	**60.03**		**$ 90**
Outstanding and exercisable at September 30, 2007	**4,079**	**$ 60.88**	**2.96**	**$ 96**

(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 $193 million and $23 million in the nine months ended September 30, 2007 and 2006, respectively.

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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 $35 million and $2 million of excess tax benefits were realized for the nine months ended September 30, 2007 and 2006, 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, 2007:

	Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	1,246	$ 65.43
Granted	**243**	**89.03**
Vested	**(342)**	**65.62**
Cancelled and forfeited	**(35)**	**75.65**
Nonvested at September 30, 2007	**1,112**	**$ 70.21**

As of September 30, 2007, unrecognized compensation cost related to nonvested restricted stock awards totaled approximately $31 million and is expected to be recognized over a weighted-average period of 1.5 years. Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. We continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but are now required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. We recognized compensation cost related to awards previously granted to retirement-eligible employees of approximately $1 million for the three months ended September 30, 2007 and 2006, and approximately $3 million and $4 million in the nine months ended September 30, 2007 and 2006, respectively. At September 30, 2007, unrecognized compensation cost for restricted stock awards held by retirement-eligible employees totaled approximately $2 million.

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 and total shareholder return relative to that of a peer group of companies. Goal-based stock awards were also granted in lieu of cash-based performance grants to certain officers who had not achieved a certain level of share ownership. At September 30, 2007, the targeted number of shares to be issued is approximately 148 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:

	Targeted Number of Shares (thousands)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2007	97	$ 69.53
Granted	**77**	**88.53**
Vested	**(11)**	**69.53**
Cancelled and forfeited	**(15)**	**69.97**
Nonvested at September 30, 2007	**148**	**$ 79.48**

At September 30, 2007, unrecognized compensation cost related to nonvested goal-based stock awards totaled approximately $8 million and is expected to be recognized over a weighted-average period of 1.6 years.

Cash-Based Performance Grant

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested

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capital and total shareholder return relative to that of a peer group of companies. At September 30, 2007, 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.

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, 2007, the targeted amount of the grant is $12 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, 2007, a liability of $15 million has been accrued for these awards.

Note 19. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006, Note 15 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, or Note 18 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, nor have any significant new matters arisen during the three months ended September 30, 2007.

Long-Term Purchase Agreements

In connection with the sale of our offshore E&P operations, Eni has indemnified us and assumed the post-closing unconditional purchase obligations associated with these operations. As a result, the following long-term commitments at December 31, 2006 that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services, are now the responsibility of Eni:

(millions)	2007	2008	2009	2010	2011	Thereafter	Total
Production handling for gas and oil production operations	$ 54	$ 43	$ 26	$ 15	$ 11	$ 5	$ 154

Lease Commitments

In connection with the sale of our non-Appalachian E&P business, the purchasers indemnified us and assumed the post-closing obligations associated with non-Appalachian lease commitments. Following the completion of the sale of our non-Appalachian E&P business, our lease commitments, as shown in our Annual Report on Form 10-K for the year ended December 31, 2006, were reduced as follows:

(millions)	2007	2008	2009	2010	2011	Thereafter	Total
Total lease commitments	$ 209	$ 182	$ 163	$ 131	$ 119	$ 294	$ 1,098
Less: non-Appalachian E&P business	(81)	(62)	(55)	(33)	(26)	(40)	(297)
Total lease commitments as adjusted at December 31, 2006	$ 128	$ 120	$ 108	$ 98	$ 93	$ 254	$ 801

Litigation

In 2006, Gary P. Jones and others filed suit against DTI, Dominion Exploration and Production, Inc. (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. In the first quarter of 2007, we established a litigation reserve representing our best estimate of the probable loss related to this matter. In the third quarter of 2007, we increased the litigation reserve to reflect our revised 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.

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Guarantees

At September 30, 2007, we had issued $41 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. 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, 2007, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[1]
Subsidiary debt[2]	$ 47	$ 47
Commodity transactions[3]	3,097	495
Lease obligation for power generation facility[4]	935	935
Nuclear obligations[5]	383	302
Other	275	148
Total	$ 4,737	$ 1,927

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of September 30, 2007, 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 a DEI subsidiary. In the event of default by the subsidiary, 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 operating expenses of Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage as part of satisfying certain Nuclear Regulatory Commission requirements concerned with ensuring adequate funding for the operations of nuclear power stations.

Surety Bonds and Letters of Credit

As of September 30, 2007, we had also purchased $88 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $402 million. We enter into these arrangements to facilitate commercial transactions by our subsidiaries with third parties.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at September 30, 2007, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2004, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately $16 billion, for breach of certain corporate representations (e.g. title to shares, due authorization), with maximum indemnity exposure for other general business representations (e.g. environmental, contracts, employee matters, etc.) being generally limited to approximately 10% or less of the purchase price for a set period of time after closing. We believe that it is unlikely that we would be required to perform under these indemnifications and have not recognized any significant liabilities related to these arrangements.

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Note 20. 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, 2007 provision for credit losses, that it is unlikely that 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 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. 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. 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 is calculated prior to the application of collateral. At September 30, 2007, our gross credit exposure totaled $764 million. After the application of collateral, our credit exposure was reduced to $758 million. Of this amount, investment grade counterparties, including those internally rated, represented 88% and no single counterparty exceeded 9%.

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Note 21. Employee Benefit Plans

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

(millions)	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
Three Months Ended September 30,				
Service cost	**$ 36**	$ 30	**$ 13**	$ 15
Interest cost	**70**	50	**20**	17
Expected return on plan assets	**(124)**	(86)	**(17)**	(12)
Amortization of prior service cost (credit)		1	**(1)**	(1)
Amortization of transition obligation				1
Amortization of net loss	**12**	22	**2**	5
Settlements and curtailments(1)			**(1)**	
Net periodic benefit cost (credit)(2)	**$ (6)**	$ 17	**$ 16**	$ 25
Nine Months Ended September 30,				
Service cost	**$ 89**	$ 95	**$ 41**	$ 55
Interest cost	**172**	158	**58**	61
Expected return on plan assets	**(305)**	(271)	**(53)**	(44)
Amortization of prior service cost (credit)	**2**	3	**(4)**	(3)
Amortization of transition obligation			**2**	3
Amortization of net loss	**30**	69	**5**	20
Benefit enhancement(3)	**3**		**9**	
Settlements and curtailments(1)	**7**	6	**(1)**	
Net periodic benefit cost (credit)(2)	**$ (2)**	$ 60	**$ 57**	$ 92

(1) Relates to the pending sale of Peoples and Hope and sale of our non-Appalachian E&P business.

(2) Reduction in pension and other postretirement benefit costs, primarily reflecting an increase in the associated discount rate.

(3) Represents a one-time benefit enhancement for certain employees in connection with the disposition of our non-Appalachian E&P business.

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, 2007. We do not expect to make any contributions to our pension plans during the remainder of the year. We expect to contribute approximately $23 million to our other postretirement benefit plans during the fourth quarter of 2007.

Note 22. Operating Segments

Our Company is organized primarily on the basis of products and services sold in the U.S. We manage our operations through the following segments.

Dominion Delivery includes our regulated electric and gas distribution and customer service businesses, as well as nonregulated retail energy marketing operations.

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and the Cove Point LNG facility. It also includes gathering and extraction activities, certain Appalachian natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading.

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

Dominion E&P includes our gas and oil exploration, development and production operations. These operations were located in several major producing basins in the lower 48 states, including the outer continental shelf and deepwater areas of the Gulf of Mexico, West Texas, Mid-Continent, the Rockies and Appalachia. We have sold all of our non-Appalachian natural gas and oil E&P operations.

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management, the remaining assets of DCI and the net impact of the discontinued operations of the Peaker facilities and the Canadian E&P business. 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. 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 segment. In the nine months ended September 30, 2007 and 2006, we reported a net benefit of $939 million and net expenses of $111 million, respectively, in the Corporate segment attributable to our operating segments.

The net benefit in 2007 largely resulted from:

- A $3.6 billion ($2.1 billion after-tax) net gain resulting from the completion of the sale of our U.S. non-Appalachian E&P business, attributable to Dominion E&P; partially offset by
- A $544 million ($347 million after-tax) charge predominantly due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges, attributable to Dominion E&P. As a result of the sale of our U.S. non-Appalachian E&P business, it became probable that the forecasted sales of gas and oil would not occur;
- A $387 million ($252 million after-tax) charge related to the impairment of Dresden, attributable to Dominion Generation;
- A $259 million ($158 million after-tax) extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, attributable to Dominion Generation;
- A $236 million ($140 million after-tax) charge for the recognition of a long-term power sales agreement at State Line, that no longer qualifies for the normal purchase and sales exemption due to the expected termination of the agreement in the fourth quarter 2007, attributable to Dominion Generation; and
- A $171 million ($108 million after-tax) charge for the recognition of certain forward gas contracts that no longer qualify for the normal purchase and sales exemption as a result of the sale of our U.S. non-Appalachian E&P business, attributable to Dominion E&P.

The net expenses in 2006 primarily related to the impact of a $167 million ($103 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to Dominion Delivery.

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:

(millions)	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P	Corporate	Adjustments/ Eliminations	Consolidated Total
Three Months Ended							
September 30,							
2007							
Total revenue from external customers	**$ 673**	**$ 134**	**$ 2,229**	**$ 178**	**$ 23**	**$ 352**	**$ 3,589**
Intersegment revenue	**3**	**453**	**31**	**51**	**160**	**(698)**	
Total operating revenue	**676**	**587**	**2,260**	**229**	**183**	**(346)**	**3,589**
Loss from discontinued operations, net of tax					**(3)**		**(3)**
Net income	**74**	**61**	**403**	**38**	**1,741**		**2,317**
2006							
Total revenue from external customers	$ 650	$ 198	$ 1,996	$ 829	$ (25)	$ 325	$ 3,973
Intersegment revenue	2	382	29	50	186	(649)	
Total operating revenue	652	580	2,025	879	161	(324)	3,973
Loss from discontinued operations, net of tax					(1)		(1)
Net income (loss)	78	102	253	297	(76)		654
Nine Months Ended							
September 30,							
2007							
Total revenue from external customers	**$ 3,100**	**$ 737**	**$ 5,745**	**$ 1,411**	**$ 54**	**$ 933**	**$ 11,980**
Intersegment revenue	**19**	**1,156**	**98**	**164**	**475**	**(1,912)**	
Total operating revenue	**3,119**	**1,893**	**5,843**	**1,575**	**529**	**(979)**	**11,980**
Extraordinary item					**(158)**		**(158)**
Loss from discontinued operations, net of tax					**(5)**		**(5)**
Net income	**356**	**232**	**623**	**314**	**715**		**2,240**
2006							
Total revenue from external customers	$ 3,059	$ 1,043	$ 5,218	$ 2,406	$ (102)	$ 751	$ 12,375
Intersegment revenue	8	945	110	168	567	(1,798)	
Total operating revenue	3,067	1,988	5,328	2,574	465	(1,047)	12,375
Income from discontinued operations, net of tax					14		14
Net income (loss)	314	277	456	615	(313)		1,349

In the fourth quarter of 2007, we will realign our business units to reflect our strategic refocusing and begin managing our daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. DVP will include our regulated electric distribution and electric transmission operations in Virginia and North Carolina, as well as our nonregulated retail energy marketing and customer service operations. Dominion Generation will continue to include our regulated and merchant power generation. Dominion Energy will include our regulated natural gas distribution, transmission, storage and LNG operations, Appalachian-based natural gas and oil E&P operations and producer services.

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DOMINION RESOURCES, INC.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Dominion. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms Dominion, Company, we, our and us are used throughout MD&A and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one 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, should, could, plan, may 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 winter 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, 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;

Capital market conditions, including price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;

Fluctuations in interest rates;

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;

Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of Peoples and Hope;

Risks associated with the realignment of our operating assets, including the potential dilutive effect on earnings in the near term;

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

Completing the divestiture of investments held by our financial services subsidiary, DCI; and

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Changes in rules for RTOs in which we participate, including changes in rate designs and new and evolving capacity models. 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, 2007 and June 30, 2007 and in our Annual Report on Form 10-K for the year ended December 31, 2006.

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, 2007, 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, 2006. The policies disclosed included the accounting for derivative contracts at fair value, goodwill and long-lived asset impairment testing, asset retirement obligations, employee benefit plans, regulated operations, 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 5 to our Consolidated Financial Statements for a discussion of the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations.

Results of Operations

Presented below is a summary of our consolidated results for the quarter and year-to-date periods ended September 30, 2007 and 2006:

(millions, except EPS)	2007	2006	$ Change
Third Quarter			
Net income	**$ 2,317**	$ 654	$ 1,663
Diluted EPS	**7.24**	1.85	5.39
Year-To-Date			
Net income	**$ 2,240**	$ 1,349	$ 891
Diluted EPS	**6.58**	3.84	2.74

Overview

Third Quarter 2007 vs. 2006

Net income increased by 254% to $2.3 billion. Diluted EPS increased to $7.24 and includes $0.15 of share accretion resulting from the repurchase of shares with proceeds received from the sale of our non-Appalachian E&P business. Favorable drivers include the gain on the sale of our U.S. non-Appalachian E&P business, higher realized prices for our gas and oil production and the reapplication of deferral accounting effective July 1, 2007, for Virginia jurisdiction fuel costs at our utility generation operations. Unfavorable drivers include a decrease in gas and oil production due to the sale of our U.S. non-Appalachian E&P business, charges related to the early extinguishment of outstanding debt associated with the completion of our debt tender offer in July 2007, a charge for the expected termination of a long-term power sales agreement at State Line and the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes.

Year-To-Date 2007 vs. 2006

Net income increased by 66% to $2.2 billion. Diluted EPS increased to $6.58 and includes $0.11 of share accretion resulting from the repurchase of shares with proceeds received from the sale of our non-Appalachian E&P business. Favorable drivers include the gain on the sale of our U.S. non-Appalachian E&P business, higher realized prices for our gas and oil production, higher margins at our merchant generation business and the reapplication of deferral accounting effective July 1, 2007, for Virginia jurisdiction fuel costs at our utility generation operations. Unfavorable drivers include a decrease in gas and oil production due to the sale of our U.S. non-Appalachian E&P business, 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, charges related to the early extinguishment of outstanding debt associated with the completion of our debt tender offer in July 2007, a charge due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges as a result of the sale of our U.S. non-Appalachian E&P business, a charge for the expected termination of a long-term power sales agreement at State Line and the absence of business interruption insurance revenue received in 2006, associated with the 2005 hurricanes.

Analysis of Consolidated Operations

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

	Third Quarter			Year-To-Date		
(millions)	**2007**	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
Operating Revenue	**$ 3,589**	$ 3,973	$ (384)	**$ 11,980**	$ 12,375	$ (395)
Operating Expenses						
Electric fuel and energy purchases	**914**	1,057	(143)	**2,742**	2,580	162
Purchased electric capacity	**111**	122	(11)	**339**	361	(22)
Purchased gas	**346**	343	3	**2,024**	2,153	(129)
Other energy-related commodity purchases	**64**	144	(80)	**184**	862	(678)
Other operations and maintenance	**1,159**	502	657	**3,906**	2,123	1,783
Gain on sale of U.S. non-Appalachian E&P business	**(3,617)**		(3,617)	**(3,602)**		(3,602)
Depreciation, depletion and amortization	**284**	389	(105)	**1,116**	1,146	(30)
Other taxes	**113**	122	(9)	**436**	430	6
Other income	**33**	43	(10)	**125**	134	(9)
Interest and related charges	**437**	256	181	**974**	764	210
Income tax expense	**1,498**	421	1,077	**1,576**	750	826
Extraordinary item, net of tax				**(158)**		(158)

An analysis of our results of operations for the third quarter and year-to-date periods of 2007 compared to the third quarter and year-to-date periods of 2006 follows:

Third Quarter 2007 vs. 2006

Operating Revenue decreased 10% to $3.6 billion, primarily reflecting:

A $299 million decrease in sales of gas and oil production primarily due to lower volumes ($589 million), partially offset by higher realized prices ($290 million);

A $269 million decrease related to business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;

An $82 million decrease in nonutility coal sales, primarily from lower sale volumes related to exiting certain sales activities. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and

A $35 million decrease in sales of extracted products due to the sale of our U.S. non-Appalachian E&P business.

These decreases were partially offset by:

A $147 million increase in revenue from our electric utility operations, largely resulting from:

- A $70 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
- A $46 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($25 million) and new customer connections ($21 million) primarily in our residential and commercial customer classes; and
- A $22 million increase in sales to wholesale customers.

An $87 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in New England Power Pool (NEPOOL) and PJM; and

A $74 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*.

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Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 14% to $914 million, primarily reflecting the combined impact of the following:

- A $212 million decrease for utility generation operations primarily due to the reapplication of deferral accounting for Virginia jurisdiction fuel costs beginning on July 1, 2007. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $26 million due to higher consumption of fossil fuel and purchased power resulting primarily from a change in generation mix. This increase was more than offset by a $238 million reduction in fuel expenses, primarily to defer fuel costs that were in excess of current period fuel rate recovery; partially offset by
- A $38 million increase related to our retail energy marketing operations resulting from an increase in volume ($19 million) and higher prices ($19 million).

Other energy-related commodity purchases expense decreased 56% to $64 million, primarily due to an $80 million decrease in the cost of nonutility coal sales, discussed in *Operating Revenue*.

Other operations and maintenance expense increased to $1.2 billion, primarily reflecting the combined effects of:

- A $236 million charge related to the expected termination of a long-term power sales agreement at State Line;
- $86 million of impairment charges related to DCI investments;
- A $71 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is more than offset by a corresponding increase in *Operating Revenue;*
- A $62 million increase primarily due to the inclusion of financial transmission rights revenue, which is used to offset congestion costs associated with PJM power purchases incurred by our utility generation operations, in *Electric fuel and energy purchases expense*, beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction;
- A $46 million increase primarily due to the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were dedesignated following the 2005 hurricanes;
- A $45 million decrease in gains from the sales of emissions allowances held for consumption; and
- A $27 million charge resulting from the accrual of litigation reserves.

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

Depreciation, depletion and amortization decreased 27% to $284 million, principally due to decreased oil and gas production resulting from the sale of our U.S. non-Appalachian E&P business.

Other income decreased 23% to $33 million, resulting primarily from lower decommissioning trust earnings due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, since they are deferred as a regulatory liability.

Interest and related charges increased 71% to $437 million, resulting principally from charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007, partially offset by a reduction in interest expense resulting from the retirement of this debt.

Income tax expense increased to $1.5 billion, reflecting income tax expense on the gain realized from the sale of our U.S. non-Appalachian E&P business.

Year-To-Date 2007 vs. 2006

Operating Revenue decreased 3% to $12 billion, primarily reflecting:

- A $422 million decrease in revenue from sales of oil purchased by E&P operations, primarily due to the impact of netting sales and purchases of oil under buy/sell arrangements associated with the implementation of EITF 04-13 in 2006. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense;*

- A $269 million decrease related to business interruption insurance revenue received in 2006, associated with the 2005 hurricanes;

- A $242 million decrease in gas sales by our gas distribution operations reflecting the combined effects of:

  - A $200 million decrease reflecting lower gas prices; and

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- A $198 million decrease resulting from the migration of customers to energy choice programs; partially offset by
- A $156 million increase in volumes due to an increase in the number of heating degree days, primarily in the first quarter of 2007, and changes in customer usage patterns and other factors. This decrease was more than offset by a corresponding decrease in *Purchased gas expense.*

- A $227 million decrease in nonutility coal sales, primarily from lower sale volumes ($210 million) related to exiting certain sales activities and lower prices ($17 million). This decrease was more than offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A $210 million decrease in sales of gas and oil production primarily due to lower volumes ($770 million), partially offset by higher realized prices ($560 million);
- A $58 million decrease in our producer services business as the result of lower margins related to price risk management activities;
- A $52 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts primarily due to the implementation of EITF 04-13 and a reduction in quantities of purchased gas. This decrease was more than offset by a corresponding decrease in *Purchased gas expense*; and
- A $40 million decrease in the sales of emissions allowances held for resale. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense.*

These decreases were partially offset by:

- A $362 million increase in revenue from our electric utility operations, largely resulting from:
  - A $125 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($71 million) and new customer connections ($54 million) primarily in our residential and commercial customer classes;
  - A $90 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days;
  - A $56 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
  - A $50 million increase in sales to wholesale customers; and
  - A $32 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM.

- A $288 million increase for merchant generation operations, primarily reflecting higher realized prices for nuclear and fossil operations, increased volumes for fossil operations and higher capacity revenue associated with new capacity markets in NEPOOL and PJM;

- A $233 million increase associated with hedging activities for our merchant generation assets. The effect of this increase was largely offset by a corresponding increase in *Other operations and maintenance expense*;

- A $135 million increase in gas sales by retail energy marketing activities due to increased customer accounts ($178 million) partially offset by lower contracted sales prices ($43 million). This increase was largely offset by a corresponding increase in *Purchased gas expense*; and

- A $66 million increase in gas transportation and storage revenue primarily attributable to our gas distribution operations due to increased volumes and higher prices.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 6% to $2.7 billion, primarily reflecting:

- An $80 million increase related to our retail energy marketing operations resulting from higher prices;

- A $59 million increase for our merchant generation operations primarily due to higher commodity prices and increased fossil fuel consumption; and

- A $12 million increase for utility generation operations. The underlying fuel costs, including those subject to deferral accounting, increased by approximately $237 million due to higher consumption of fossil fuel and purchased power resulting from an increase in the number of heating and cooling degree days, higher commodity costs and a change in generation mix. This increase was largely offset by a $225 million reduction in fuel expenses, primarily to defer fuel costs that were in excess of current period fuel rate recovery.

Purchased gas expense decreased 6% to $2.0 billion, principally resulting from:

- A $192 million decrease in costs attributable to gas distribution operations, primarily reflecting lower prices as discussed in *Operating Revenue*; and

- A $59 million decrease related to E&P operations, resulting from the impact of netting purchases and sales of gas under buy/sale arrangements due to the implementation of EITF 04-13 and a reduction in purchased gas quantities. The effect of this decrease is largely offset by a corresponding decrease in *Operating Revenue.*

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These decreases were partially offset by:

- A $111 million increase associated with retail energy marketing activities, due to higher volumes ($162 million), partially offset by lower prices ($51 million), as discussed in *Operating Revenue*; and
- A $19 million increase associated with our producer services business, due to the net impact of an increase in volumes partially offset by lower prices.

Other energy-related commodity purchases expense decreased 79% to $184 million, primarily attributable to the following factors, all of which are discussed in *Operating Revenue*:

- A $409 million decrease as a result of the implementation of EITF 04-13;
- A $229 million decrease in the cost of nonutility coal sales; and
- A $38 million decrease in the cost of sales of emissions allowances held for resale.

Other operations and maintenance expense increased 84% to $3.9 billion, resulting from:

- A $544 million charge predominantly due to the discontinuance of hedge accounting for certain gas and oil hedges and subsequent changes in the fair value of these hedges as a result of the sale of our U.S. non-Appalachian E&P business;
- A $387 million impairment charge related to the sale of Dresden;
- A $236 million charge related to the expected termination of a long-term power sales agreement at State Line;
- A $211 million increase primarily related to hedging activities associated with our merchant generation assets. The effect of this increase is more than offset by a corresponding increase in *Operating Revenue;*
- A $177 million increase primarily due to the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were dedesignated following the 2005 hurricanes;
- A $171 million charge primarily due to the termination of VPP agreements as a result of the sale of our U.S. non-Appalachian E&P business;
- $86 million of impairment charges related to DCI investments;
- A $63 million increase due to a decrease in gains from the sale of emissions allowances held for consumption;

- A $53 million charge resulting from the accrual of litigation reserves; and

- A $40 million increase primarily due to the inclusion of financial transmission rights revenue, which is used to offset congestion costs associated with PJM power purchases incurred by our utility generation operations, in *Electric fuel and energy purchases expense*, beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction.

These charges were partially offset by the absence of the following 2006 items:

- A $167 million charge related to the write-off of certain regulatory assets in connection with the pending sale of Peoples and Hope; and

- A $60 million charge due to the elimination of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

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

Interest and related charges increased 27% to $974 million, resulting principally from charges related to the early extinguishment of outstanding debt associated with our debt tender offer completed in July 2007, partially offset by a reduction in interest expense resulting from the retirement of this debt.

Income tax expense increased to $1.6 billion, reflecting income tax expense on the gain realized from the sale of our U.S. non-Appalachian E&P business.

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

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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 operating segments to net income for the quarter and year-to-date periods ended September 30, 2007 and 2006:

	Net Income			Diluted EPS		
Third Quarter	**2007**	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
(millions, except EPS)						
Dominion Delivery	**$ 74**	$ 78	$ (4)	**$ 0.23**	$ 0.22	$ 0.01
Dominion Energy	**61**	102	(41)	**0.19**	0.29	(0.10)
Dominion Generation	**403**	253	150	**1.26**	0.71	0.55
Dominion E&P	**38**	297	(259)	**0.12**	0.84	(0.72)
Primary operating segments	**576**	730	(154)	**1.80**	2.06	(0.26)
Corporate	**1,741**	(76)	1,817	**5.44**	(0.21)	5.65
Consolidated	**$ 2,317**	$ 654	$ 1,663	**$ 7.24**	$ 1.85	$ 5.39
Year-To-Date						
(millions, except EPS)						
Dominion Delivery	**$ 356**	$ 314	$ 42	**$ 1.05**	$ 0.89	$ 0.16
Dominion Energy	**232**	277	(45)	**0.68**	0.79	(0.11)
Dominion Generation	**623**	456	167	**1.83**	1.31	0.52
Dominion E&P	**314**	615	(301)	**0.92**	1.75	(0.83)
Primary operating segments	**1,525**	1,662	(137)	**4.48**	4.74	(0.26)
Corporate	**715**	(313)	1,028	**2.10**	(0.90)	3.00
Consolidated	**$ 2,240**	$ 1,349	$ 891	**$ 6.58**	$ 3.84	$ 2.74

Dominion Delivery

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

	Third Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Electricity delivered (million mwhrs)[(1)]	**23.7**	23.1	3%	**64.7**	61.2	6%
Degree days (electric service area):						
Cooling[(2)]	**1,150**	1,119	3	**1,643**	1,528	8
Heating[(3)]	**5**	15	(67)	**2,365**	2,056	15
Average electric delivery customer accounts[(4)]	**2,364**	2,330	1	**2,357**	2,322	2
Gas throughput (bcf):						
Gas sales	**6**	6		**65**	68	(4)
Gas transportation	**33**	37	(11)	**186**	167	11
Heating degree days (gas service area)[(3)]	**69**	111	(38)	**3,830**	3,347	14
Average gas delivery customer accounts[(4)]:						
Gas sales	**776**	780	(1)	**782**	881	(11)
Gas transportation	**890**	893		**901**	807	12
Average retail energy marketing customer accounts[(4)]	**1,566**	1,398	12	**1,529**	1,308	17

mwhrs = megawatt hours

bcf = billion cubic feet

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(1) Includes electricity delivered through the retail choice program for our Virginia jurisdictional electric customers.

(2) 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.

(3) 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.

(4) Period average, in thousands.

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

(millions, except EPS)	Third Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS	Year-To-Date 2007 vs. 2006 Increase (Decrease) Amount	EPS
Major storm damage and service restoration[1]	$ 7	$ 0.02	$ 6	$ 0.02
Regulated electric sales:				
Customer growth	3	0.01	7	0.02
Weather	(1)		13	0.04
Bad debt expense[2]	(4)	(0.01)	(10)	(0.03)
Regulated gas sales weather	(1)		14	0.04
Retail energy marketing operations[3]			8	0.03
Other	(8)	(0.03)	4	0.01
Share accretion		0.02		0.03
Change in net income contribution	$ (4)	$ 0.01	$ 42	$ 0.16

(1) Primarily resulting from the absence in 2007 of costs associated with tropical storm Ernesto in September 2006.
(2) Decrease primarily due to charge-offs associated with our gas distribution operations.
(3) Increase in the year-to-date period reflects higher revenues largely attributable to an increase in the number of gas customers.

Dominion Energy

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

	Third Quarter 2007	2006	% Change	Year-To-Date 2007	2006	% Change
Gas transportation throughput (bcf)	**134**	128	5%	**543**	484	12%

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

(millions, except EPS)	Third Quarter 2007 vs. 2006 Increase (Decrease) Amount	EPS	Year-To-Date 2007 vs. 2006 Increase (Decrease) Amount	EPS
Producer services[1]	$ (25)	$ (0.07)	$ (39)	$ (0.11)
Gas transmission operations[2]	(13)	(0.04)	(10)	(0.03)
Electric transmission operations	(1)		3	0.01
Other	(2)	(0.01)	1	
Share accretion		0.02		0.02
Change in net income contribution	$ (41)	$ (0.10)	$ (45)	$ (0.11)

(1) For the quarter, decrease is primarily due to unfavorable price changes on price risk management activities and lower mark-to-market gains on positions economically hedging gas and storage. Decrease in the year-to-date period is primarily related to unfavorable price changes due to reduced market volatility, as compared to the post-2005 hurricane market conditions in 2006.
(2) Decrease is primarily due to a decline in market center services and higher system fuel costs.

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Dominion Generation

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

	Third Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Electricity supplied (million mwhrs)						
Utility	**23.7**	23.0	3%	**64.7**	61.2	6%
Merchant	**12.7**	11.5	10	**34.2**	32.4	6
Degree days (electric utility service area):						
Cooling	**1,150**	1,119	3	**1,643**	1,528	8
Heating	**5**	15	(67)	**2,365**	2,056	15

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

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Virginia fuel expenses(1)	$ 165	$ 0.47	$ 75	$ 0.20
Merchant generation margin(2)	48	0.14	106	0.30
Ancillary service revenue	10	0.03	22	0.06
Regulated electric sales:				
Customer growth	7	0.02	16	0.05
Weather	(2)	(0.01)	25	0.07
Sales of emissions allowances	(28)	(0.08)	(39)	(0.11)
Energy supply margin	(8)	(0.02)		
Interest expense	(6)	(0.02)	(15)	(0.04)
Outage costs(3)	(5)	(0.01)	(22)	(0.06)
Salaries, wages and benefits expense	(4)	(0.01)	(5)	(0.01)
Other	(27)	(0.08)	4	0.01
Share accretion		0.12		0.05
Change in net income contribution	$ 150	$ 0.55	$ 167	$ 0.52

(1) For the quarter and year-to-date periods, primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007 for our utility generation operations. For the year-to-date period, the benefit is partially offset by increased consumption of fossil fuel and higher purchased power costs during the first six months of the year.

(2) Primarily reflects higher overall realized prices for our New England nuclear and fossil generating assets and higher volumes and capacity revenue for other fossil generation operations. Higher prices include implementation of new capacity markets in NEPOOL and PJM.

(3) For the quarter, primarily reflects an increase in the number of scheduled outage days for our utility generation operations, partially offset by lower scheduled outage days for merchant nuclear operations. For the year-to-date period, primarily reflects higher scheduled outage days for both utility and merchant generation operations.

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Dominion E&P

Presented below are operating statistics related to our E&P operations:

	Third Quarter			Year-To-Date		
	2007	**2006**	**% Change**	**2007**	**2006**	**% Change**
Gas production (bcf)	**34.4**	75.8	(55)%	**183.1**	218.5	(16)%
Oil production (million bbls)	**0.8**	6.0	(87)	**11.2**	17.9	(37)
Average realized prices without hedging results:						
Gas (per mcf)(1)	**$ 5.89**	$ 6.34	(7)	**$ 6.59**	$ 6.86	(4)
Oil (per bbl)	**48.45**	58.59	(17)	**50.65**	57.27	(12)
Average realized prices with hedging results:						
Gas (per mcf)(1)	**$ 5.71**	$ 4.19	36	**$ 5.76**	$ 4.36	32
Oil (per bbl)	**41.70**	32.78	27	**37.24**	35.31	5
DD&A (unit of production rate per mcfe)	**$ 1.70**	$ 1.66	2	**$ 1.87**	$ 1.64	14

bbl(s) = barrel(s)

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

(1) Excludes $60 million for the three months ended September 30, 2006 and $71 million and $203 million for the nine months ended September 30, 2007 and 2006, respectively, of revenue recognized under the VPP agreements, which were terminated in the second quarter of 2007, as described in Note 6 to our Consolidated Financial Statements.

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

	Third Quarter 2007 vs. 2006 Increase (Decrease)		Year-To-Date 2007 vs. 2006 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Gas and oil production(1)	(377)	(1.07)	(453)	(1.29)
Business interruption insurance(2)	(171)	(0.48)	(171)	(0.49)
Gas and oil prices	$ 159	$ 0.45	$ 291	$ 0.83
DD&A	78	0.22	43	0.12
Operations and maintenance(3)	28	0.08	(39)	(0.11)
Interest expense	10	0.03	(4)	(0.01)
Other	14	0.04	32	0.09
Share accretion		0.01		0.03
Change in net income contribution	$ (259)	$ (0.72)	$ (301)	$ (0.83)

(1) Represents a decrease in gas and oil production related principally to the sale of our U.S. non-Appalachian E&P business.

(2) Decrease is due to the absence of business interruption insurance proceeds received in 2006 associated with the 2005 hurricanes.

(3) Lower operations and maintenance expenses for the quarter reflect overall decreases in lifting and transportation costs associated with the sale of our U.S. non-Appalachian E&P business. Higher operations and maintenance expenses in the year-to-date period, primarily reflecting the absence of a 2006 benefit from favorable changes in the fair value of certain gas and oil hedges that were de-designated following the 2005 hurricanes.

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Included below are the volumes and weighted-average prices associated with hedges in place for our Appalachian operations and fixed-term overriding royalty interests formerly associated with the VPP agreements as of September 30, 2007 by applicable time period.

	Natural Gas	
	Hedged Production	Average Hedge Price
Year	**(bcf)**	**(per mcf)**
2007	15.4	$ 7.10
2008	51.7	8.57
2009	6.7	8.43

Corporate

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

	Third Quarter			Year-To-Date		
	2007	**2006**	**$ Change**	**2007**	**2006**	**$ Change**
(millions, except EPS)						
Specific items attributable to operating segments	**$ 1,930**	$ (9)	$ 1,939	**$ 939**	$ (111)	$ 1,050
Peaker discontinued operations		(3)	3	**(28)**	(15)	(13)
Canadian E&P discontinued operations		2	(2)	**32**	28	4
Other corporate operations	**(189)**	(66)	(123)	**(228)**	(215)	(13)
Total net (expense) benefit	**$ 1,741**	$ (76)	$ 1,817	**$ 715**	$ (313)	$ 1,028
Earnings per share impact	**$ 5.44**	$ (0.21)	$ 5.65	**$ 2.10**	$ (0.90)	$ 3.00

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 22 to our Consolidated Financial Statements for discussion of these items.

Peaker Discontinued Operations

Year-To-Date 2007 vs. 2006

The increase in the loss from the discontinued operations of the Peaker facilities primarily reflects a $25 million loss on the sale of the Peaker facilities in March 2007, resulting largely from the allocation of $24 million of Generation reporting unit goodwill to the bases of the investments sold.

Other Corporate Operations

Third Quarter 2007 vs. 2006

Net expenses increased $123 million, primarily due to $267 million of charges ($163 million after-tax) related to the early retirement of outstanding debt associated with the completion of our debt tender offer in July 2007. The increase in net expenses also reflects an $86 million ($55 million after-tax) impairment charge related to certain DCI investments. These expenses were partially offset by higher income tax benefits in 2007, primarily reflecting the interim impact of changes to our estimated annual effective tax rate.

Year-To-Date 2007 vs. 2006

Net expenses increased $13 million, primarily reflecting charges related to the completion of our debt tender offer in July 2007, described above. These charges were partially offset by a $119 million tax benefit from the elimination of valuation allowances on deferred tax assets, representing federal and state tax loss carryforwards, since these losses will be utilized to offset taxable income generated from the sale of our non-Appalachian E&P business.

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, 2006 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.

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A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during the nine months ended September 30, 2007 follows:

(millions)	Amount
Net unrealized gain at December 31, 2006	$ 42
Contracts realized or otherwise settled during the period	**(43)**
Net unrealized gain at inception of contracts initiated during the period	
Changes in valuation techniques	
Other changes in fair value	**15**
Net unrealized gain at September 30, 2007	**$ 14**

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at September 30, 2007, is summarized in the following table based on the approach used to determine fair value and contract settlement or delivery dates:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value (millions)	**Less than 1 year**	**1-2 years**	**2-3 years**	**3-5 years**	**In excess of 5 years**	**Total**
Actively quoted[(1)]	$ (1)	$ 5	$ 6	$	$	$ 10
Other external sources[(2)]		3	(1)	2		4
Total	$ (1)	$ 8	$ 5	$ 2	$	$ 14

(1) Exchange-traded and over-the-counter contracts.

(2) Values based on prices from over-the-counter broker activity and industry services and, where applicable, conventional option pricing models.

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 sales of securities and additional long-term financing.

At September 30, 2007, we had $4.6 billion of unused capacity under our credit facilities, comprised of approximately $4.5 billion under our core credit facilities and $100 million available under a bilateral credit facility.

A summary of our cash flows for the nine months ended September 30, 2007 and 2006 is presented below:

(millions)	2007	2006
Cash and cash equivalents at January 1,[(1)]	**$ 142**	$ 146
Cash flows provided by (used in):		
Operating activities	**2,283**	3,486
Investing activities	**10,814**	(2,780)

Financing activities	**(12,768)**	(724)
Net increase (decrease) in cash and cash equivalents	**329**	(18)
Cash and cash equivalents at September 30,[2]	**$ 471**	$ 128

(1) 2007 amount includes $4 million of cash classified as held for sale in our Consolidated Balance Sheet.

(2) 2007 and 2006 amounts include $2 million of cash classified as held for sale in our Consolidated Balance Sheets.

Operating Cash Flows

For the nine months ended September 30, 2007, net cash provided by operating activities decreased by $1.2 billion as compared to the nine months ended September 30, 2006. The decrease was primarily due to a reduction in cash flow resulting from the sale of our non-Appalachian E&P business, the absence of business interruption insurance proceeds received in 2006, and higher income taxes paid. 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, 2007 and June 30, 2007 and in our Annual Report on Form 10-K for the year-ended December 31, 2006.

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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, 2007, 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 is calculated prior to the application of collateral.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade[1]	$ 516	$ 1	$ 515
Non-investment grade[2]	26		26
No external ratings:			
Internally rated investment grade[3]	155	5	150
Internally rated non-investment grade[4]	67		67
Total	$ 764	$ 6	$ 758

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s Investors Service (Moody s) and Standard & Poor s Ratings Services. The five largest counterparty exposures, combined, for this category represented approximately 35% of the total net credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 15% of the total net credit exposure.

(4) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.

Investing Cash Flows

Significant cash flows provided by investing activities for the nine months ended September 30, 2007, included:

- $13.7 billion of net proceeds from the sale of our non-Appalachian E&P business;
- $696 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts; and
- $339 million of net proceeds from the sale of merchant generation facilities.

Cash flows provided by investing activities for the nine months ended September 30, 2007, were partially offset by:

- $1.8 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- $1.4 billion of capital expenditures, including environmental upgrades, routine capital improvements, purchase of nuclear fuel, and construction and improvements of gas and electric transmission and distribution assets; and

$763 million for purchases of securities held as investments in our nuclear decommissioning trusts.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as a significant source 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.

Significant financing activities for the nine months ended September 30, 2007 included:

$5.8 billion for the repurchase of common stock, primarily due to the completion of our equity tender offer in August 2007;

$5.4 billion for the repayment of long-term debt and notes payable, largely resulting from the completion of our debt tender offer in July 2007;

$2.3 billion for the repayment of short-term debt; and

$704 million of dividend payments; partially offset by

$1.2 billion from the issuance of long-term debt.

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See Note 17 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions, including our debt and equity tender offers.

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, 2006, we discussed the use of capital markets by Virginia Power, CNG and us (the Dominion Companies), 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 the Dominion Companies debt. As a result of the merger of CNG with Dominion, all of CNG s former rights and obligations under its indentures have been assumed by Dominion. Subsequent to the merger, Moody s lowered its rating of CNG Senior Unsecured debt from Baa1 to Baa2 to equal their rating of Dominion s Senior Unsecured debt.

In June 2006 and September 2006, we executed Replacement Capital Covenants (RCCs) in connection with our offering of $300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and $500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. We initially designated the 8.4% Capital Securities of Dominion Resources Capital Trust III as covered debt for purposes of the RCCs. However, due to our acquisition of most of these securities in our debt tender offer in July 2007, they ceased to be eligible as covered debt for the RCCs. Under the terms of the RCCs, we are required under certain circumstances to change the series of our debt designated as covered debt under the RCCs. In the third quarter of 2007, we designated the September hybrids as covered debt under the June hybrids RCC and designated the June hybrids as covered debt under the September hybrids RCC.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of September 30, 2007 there have been no events of default under our debt covenants. Other than the change in covered debt for the RCCs discussed above, as of September 30, 2007, there have been no changes to our debt covenants.

Future Cash Payments for Contractual Obligations

As of September 30, 2007, there have been no material changes outside the ordinary course of business to the contractual obligations disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006, with the exception of the following.

In connection with the sales of our non-Appalachian E&P operations, the purchasers have indemnified us and assumed our contractual obligations associated with these operations. Additionally, we used some of the after-tax proceeds from these dispositions to reduce our outstanding debt. As a result of these transactions, our contractual obligations at December 31, 2006 have been reduced as follows:

(millions)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Total cash payments	$ 7,017	$ 6,459	$ 5,418	$ 23,682	$ 42,576
Less: non-Appalachian E&P operations	(218)	(148)	(79)	(71)	(516)
Less: debt reduction	(309)	(553)	(1,406)	(3,168)	(5,436)
Total cash payments as adjusted	$ 6,490	$ 5,758	$ 3,933	$ 20,443	$ 36,624

Planned Capital Expenditures

As of September 30, 2007, our planned capital expenditures for 2008 are expected to total approximately $3.5 billion. The decrease, as compared to the amounts originally forecasted in our Annual Report on Form 10-K for the year ended December 31, 2006, primarily reflects the sale of our non-Appalachian E&P operations, partially offset by an increase in capital spending associated with the need for additional generation in our electric utility service territory. Our planned capital expenditures include capital projects that are subject to board approval. We expect to fund our capital expenditures with cash from operations and a combination of sales of securities and short-term borrowings.

Use of Off-Balance Sheet Arrangements

Following the closing of the sale of our offshore E&P operations in July 2007, we have been released from all obligations under the off-balance sheet arrangements related to the Thunder Hawk facility and an ultra-deepwater drilling rig discussed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2006.

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With the exception of these items, as of September 30, 2007, 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, 2006.

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, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007.

Common Stock Dividend Increase and Stock Split

On October 26, 2007, our board of directors approved an increase in our quarterly common stock dividend rate. The quarterly dividend rate was increased to 79 cents per share, an 11% increase over our existing quarterly dividend rate of 71 cents per share. Stated as an annual rate, the board s action increases the dividend rate from $2.84 per share to $3.16 per share.

In a separate matter, the board of directors approved a two-for-one stock split and an increase in the number of shares of common stock the Company is authorized to issue from 500 million to 1 billion. Shareholders of record on November 9, 2007, will receive one additional share of common stock for each share held at the close of business on that date; however, the proportionate interest that a shareholder owns in the Company will not change as a result of the stock split. The additional shares will be distributed on or after November 19, 2007. Based on shares outstanding at September 30, 2007, upon the completion of the stock split Dominion will have approximately 575 million shares of common stock outstanding.

Dividends are payable on December 20, 2007, to shareholders of record on November 30, 2007. The dividend payment will be made after the stock split. As a result of the timing, shareholders of record on November 30, 2007, will receive an annual dividend rate on a post-split basis of $1.58 per share or 39.5 cents per share on a quarterly basis.

Regulatory Approval of Sale of Peoples and Hope

In March 2006, Peoples and Equitable Resources, Inc. (Equitable) filed a joint petition with the Pennsylvania Public Utility Commission (Pennsylvania Commission) seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Public Service Commission (West Virginia Commission) approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the Federal Trade Commission (FTC) filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected in November 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission s decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be separated allowing the West Virginia Commission to move forward with its review of the sale. The West Virginia Commission has established a briefing schedule that is expected to result in a final decision regarding the sale in late 2007, unless the parties reach an earlier settlement. After November 1, 2007, either Dominion or Equitable is entitled to terminate the transaction, although at this time neither party has indicated its intention to exercise its termination right.

Transmission Expansion Plan

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals. In April 2007, we, along with Trans-Allegheny Interstate Line Company, filed an application with the Virginia Commission requesting approval of the proposed construction of the

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65-mile transmission line in northern Virginia. Evidentiary hearings on this application will be held in February 2008. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 60-mile transmission line in southeastern Virginia. Evidentiary hearings will be held on this application in February 2008.

Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service area, we will need additional generation over the next 10 years. As a result, in April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith Power Station to supply electricity during periods of peak demand. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million. The Virginia Commission approved the application on August 24, 2007, and construction has commenced. Approval by the North Carolina Commission for a related affiliate transaction is still pending.

On September 13, 2007, we filed a Petition for Reconsideration requesting that the Virginia Commission modify its order of August 24, 2007 for the limited purpose of continuing the docket generally to provide us with an opportunity to file supplemental information supporting approval of a fifth combustion turbine (Unit 5) at the existing Ladysmith generating facility. The Virginia Commission granted the petition for that limited purpose on September 14, 2007 and we plan to file for approval of Unit 5 in early November 2007.

In July 2007, we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon capture compatible, clean coal powered electric generation facility to be located in Wise County, Virginia. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs including a return on common equity of 11.75% together with a 200 basis point enhancement through a rate adjustment clause. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.6 billion, at that time. A public hearing is scheduled for January 8, 2008.

PJM Rate Design

In May 2005, the Federal Energy Regulatory Commission (FERC) issued an order finding that PJM s existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings into the matter. In April 2007, FERC reaffirmed PJM s existing transmission service rate design. FERC also determined that the costs of new PJM-planned transmission facilities that operate at or above 500 kV will be allocated on a PJM region-wide basis, while the costs of new PJM-planned facilities that operate below 500 kV will be assigned to zones within the PJM region based on a new model to be developed in further proceedings. Rehearing of the FERC order was sought in May 2007. We cannot predict whether the FERC decision with regard to the allocation of costs of facilities operating at or above 500 kV will be modified upon rehearing. In September 2007, a settlement proposal was filed at FERC with regard to the allocation of costs of PJM-planned facilities that operate below 500 kV. Such settlement proposal is still pending.

Ohio Rate Case

In August 2007, The East Ohio Gas Company (East Ohio) filed an application to increase base rates. In this rate case, East Ohio requests approval of an increase in operating revenues of over $73 million to provide a rate of return on rate base of 8.72%. As part of its request, East Ohio is proposing to install automated meter reading devices for all of its 1.2 million customers over a 5-year period and to spend up to an additional $5.5 million per year over a three-year period on demand side management programs if the Public Utilities Commission of Ohio approves a decoupling mechanism that would automatically adjust base rates in order to maintain base rate revenues per customer at the level approved in the rate case. In addition, East Ohio is proposing to expand its gross receipts tax rider to apply to all amounts billed for services, rather than just gas cost recoveries, thereby excluding gross receipts tax from base rates.

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Depreciation Study

In October 2007, we revised the depreciation rates for our utility generation assets to reflect the results of a new depreciation study, which incorporates changes in service life estimates and the property, plant and equipment accounting policy changes that were made upon the reapplication of SFAS No. 71, as discussed in Note 5 to our Consolidated Financial Statements. This change is expected to increase annual depreciation expense by approximately $54 million ($33 million after-tax) prospectively.

Environmental Matters

Virginia Energy Plan

The Virginia Energy Plan, released by the Governor of Virginia in September 2007, set a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025, and has called for the formation of a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of specific requirements and timing is uncertain, and we cannot predict the financial impact on our operations at this time.

Clean Air Act Compliance

Illinois has finalized regulations to implement the Clean Air Interstate Rule with requirements more strict than the federal rule. The Indiana Air Pollution Control Board has approved adoption of the federal Clean Air Mercury Rule, with only minor changes. Projected capital expenditures at our affected facilities remain consistent with the estimates provided in our Annual Report on Form 10-K for the year ended December 31, 2006.

Clean Water Act Compliance

In October 2003, the EPA and the Massachusetts Department of Environmental Protection each issued new National Pollutant Discharge Elimination System (NPDES) permits for the Brayton Point Power Station (Brayton Point). The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. In November 2003, appeals were filed with the EPA Environmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006, the EAB remanded a portion of the EPA s NPDES permit to the EPA for reconsideration. In November 2006, EPA issued its determination on remand regarding four remaining issues appealed by Brayton Point concerning its NPDES permit. In January 2007, Brayton Point appealed three of those issues to the EPA EAB. In September 2007, EAB denied review of those issues, thus concluding the EPA s review process. In October 2007, Brayton Point filed a motion with the Regional Administrator for the U.S. EPA seeking a stay of the effectiveness of the Station s NPDES permit. On October 26, 2007, the Regional Administrator denied the motion. Also on October 26, 2007, Brayton Point filed an appeal of the permit with the U.S. Court of Appeals. On October 30, 2007, Brayton Point filed a motion requesting the U.S. Court of Appeals stay the permit pending resolution of its petition for review. EPA has agreed to a temporary stay until November 16, 2007, to allow for briefing of the motion for stay. Until the appeals process is completed, the outcome of this matter cannot be predicted. However, should the appeals process result in an unfavorable outcome, we would likely be required to install cooling towers, which could result in material capital expenditures in future years.

DOMINION RESOURCES, INC.

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. Management s Discussion and Analysis of Financial Condition and Results of Operations 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, foreign currency exchange rates and equity security prices as described below. Commodity price risk is present in our electric operations, energy marketing and trading operations, and gas and oil production and procurement operations due to the exposure to market shifts in prices received and paid for electricity, natural gas, oil 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. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. 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, interest rates and foreign currency exchange rates.

Commodity Price Risk

We manage price risk associated with purchases and sales of electricity, natural gas, oil, and certain other commodities using commodity-based financial derivative instruments held for non-trading purposes. 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 risk are executed within established policies and procedures and include instruments such as futures, forwards, swaps and options that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the fair value 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 actively quoted 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 $274 million and $597 million as of September 30, 2007 and December 31, 2006, respectively. The decrease is primarily due to the execution of offsetting derivatives related to the divestiture of our non-Appalachian E&P business. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $5 million and $3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of September 30, 2007 and December 31, 2006, 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.

Foreign Currency Exchange Risk

We manage our foreign currency exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% decrease in relevant foreign exchange rates would have resulted in a decrease of approximately $2 million and $3 million in the fair value of currency forward contracts held by us at September 30, 2007 and December 31, 2006, respectively.

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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, 2007, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $7 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2006, would have resulted in a decrease in annual earnings of approximately $25 million.

In addition, we retain ownership of mortgage investments, including subordinated bonds and interest-only residual assets retained from securitizations of mortgage loans originated and purchased in prior years. Note 27 to our Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2006 discusses the impact of changes in value of these investments.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $35 million and $59 million for the nine months ended September 30, 2007 and 2006, respectively, and $63 million for the year ended December 31, 2006. We recorded, in AOCI, unrealized gains on these investments of $69 million for the nine months ended September 30, 2007, and net unrealized gains on these investments of $84 million for the nine months ended September 30, 2006. For the year ended December 31, 2006, we recorded, in AOCI, unrealized gains on these investments of $194 million.

Following the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations, gains or losses on those decommissioning trust investments are deferred as regulatory liabilities or regulatory assets, respectively.

We also sponsor employee pension and other postretirement benefit plans that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans.

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including the Chief Executive Officer and Chief Financial Officer, 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 Chief Executive Officer and Chief Financial Officer have concluded that Dominion s disclosure controls and procedures are effective.

In accordance with the purchase and sale agreements related to the divestiture of certain non-Appalachian E&P operations, Dominion agreed to provide transition services to buyers for a period extending into 2008, including services that affect internal controls over financial reporting. As such, certain transaction processing, financial reporting and information technology controls related to these non-Appalachian E&P operations were temporarily added or modified during the period to help support these services. For further discussion related to the divestiture, see Notes 1 and 6 to our Consolidated Financial Statements. Apart from this, there have been no significant changes in Dominion s internal control over financial reporting during the quarter ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, Dominion s internal control over financial reporting.

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DOMINION RESOURCES, INC.

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 October 2003, the Environmental Protection Agency (EPA) and the Massachusetts Department of Environmental Protection each issued new National Pollutant Discharge Elimination System (NPDES) permits for the Brayton Point Power Station (Brayton Point). The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. In November 2003, appeals were filed with the EPA Environmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006, the EAB remanded a portion of the EPA s NPDES permit to the EPA for reconsideration. In November 2006, EPA issued its determination on remand regarding four remaining issues appealed by Brayton Point concerning its NPDES permit. In January 2007, Brayton Point appealed three of those issues to the EPA EAB. In September 2007, EAB denied review of those issues, thus concluding the EPA s review process. In October 2007, Brayton Point filed a motion with the Regional Administrator for the U.S. EPA seeking a stay of the effectiveness of the Station s NPDES permit. On October 26, 2007, the Regional Administrator denied the motion. Also on October 26, 2007, Brayton Point filed an appeal of the permit with the U.S. Court of Appeals. On October 30, 2007, Brayton Point filed a motion requesting the U.S. Court of Appeals stay the permit pending resolution of its petition for review. EPA has agreed to a temporary stay until November 16, 2007, to allow for briefing of the motion for stay. Until the appeals process is completed, the outcome of this matter cannot be predicted.

In December 2006 and January 2007, we submitted self-disclosure notifications to EPA Region 8 regarding three E&P facilities in Utah that have potentially violated Clean Air Act permitting requirements. On July 31, 2007, a third party purchased Dominion s E&P assets in Utah including these facilities and under the purchase and sale agreement the third party assumed responsibility for the resolution of any enforcement action or Consent Decree, including penalties.

In March 2006, Peoples and Equitable filed a joint petition with the Pennsylvania Commission seeking approval of the purchase by Equitable of all of the stock of Peoples and Hope. In April 2006, Hope and Equitable filed a joint petition seeking West Virginia Commission approval of the purchase by Equitable of all of the stock of Hope. In April 2007, the Pennsylvania Commission approved a joint settlement approving the sale in Pennsylvania. Following the approval of the sale of Peoples by the Pennsylvania Commission, the FTC filed an action in federal court seeking to block the transaction. Such action was denied and the case is currently on appeal by the FTC in the 3rd U.S. Circuit Court of Appeals. A decision in such case is expected in November 2007. In West Virginia, the regulatory process had been delayed by the West Virginia Commission s decision to include certain gas purchasing practices in its examination of the sale. However, in July 2007, the West Virginia Commission ordered that the matter of the acquisition of Hope by Equitable and the matter related to certain gas purchasing practices of Hope be bifurcated allowing the West Virginia Commission to move forward with its review of the sale. The West Virginia Commission has established a briefing schedule that is expected to result in a final decision regarding the sale in late 2007, unless the parties reach an earlier settlement.

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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, 2006 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007, which factors should be taken into consideration when reviewing the information contained in this report. With the exception of the risk factor below, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2007 and June 30, 2007. 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.

The sale of most of our E&P assets is expected to reduce our operating revenues and may not yield the benefits that we expect. Since June 2007 we have sold approximately 5.5 Tcfe equivalent of proved natural oil and gas reserves for approximately $13.9 billion. This sale of most of our E&P assets is expected to reduce our operating revenues in the near-term and may not yield the benefits that we expect.

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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
7/1/07-7/31/07	7,445	$ 87.16	N/A	31,525,074 shares/$3.07 billion
8/1/07-8/31/07	2,452,135	86.52	2,434,600	29,090,474 shares/$2.86 billion
9/1/07-9/30/07	2,109,308	85.25	2,104,900	26,985,574 shares/$2.68 billion
Total	4,568,888	$ 85.94	4,539,500	26,985,574 shares/$2.68 billion

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

In addition to the table above, in August 2007, we completed an equity tender offer, approved by our Board of Directors, for the purchase of approximately 57,751,767 shares at a price of $91 per share, for a total cost of approximately $5.3 billion, excluding fees and expenses related to the tender.

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).
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).
4.1	Dominion Resources, Inc. agrees to furnish to the Securities and Exchange Commission 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.
4.2	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference).
12	Ratio of earnings to fixed charges (filed herewith).
31.1	Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the Securities and Exchange Commission by Registrant s Chief Executive Officer and Chief Financial Officer, 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

November 1, 2007

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

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