VIRGINIA ELECTRIC & POWER CO
Form 10-K/A
October 13, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

OR

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

Commission File Number 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

Virginia **(State or other jurisdiction of** **incorporation or organization)**	**54-0418825** **(I.R.S. Employer** **Identification No.)**
120 Tredegar Street **Richmond, Virginia** **(Address of principal executive offices)**	**23219** **(Zip Code)**

(804) 819-2000

(Registrant s telephone number)

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Preferred Stock (cumulative), $100 par value, $5.00 dividend	**New York Stock Exchange**

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

None

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

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

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

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

10-K or any amendment to this Form 10-K. x

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

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

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

The aggregate market value of the voting stock held by non-affiliates as of the last business day of the registrant s most recently completed second fiscal quarter was zero.

As of February 1, 2009, there were issued and outstanding 209,833 shares of the registrant s common stock, without par value, all of which were held, beneficially and of record, by Dominion Resources, Inc.

DOCUMENTS INCORPORATED BY REFERENCE.

None

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EXPLANATORY NOTE

Virginia Electric and Power Company is filing this Amendment No. 1 to its Annual Report on Form 10-K for the fiscal year ended December 31, 2008, as filed with the Securities and Exchange Commission on February 26, 2009, in order to revise the Chief Executive Officer and Chief Financial Officer certifications filed as Exhibits 31.1 and 31.2 to the original Form 10-K, which inadvertently omitted certain language regarding internal control over financial reporting required to be included in paragraph 4. In addition, in connection with the filing of this amendment, we are including an updated consent letter from our independent registered public accounting firm as an exhibit and we are furnishing certain other currently dated certifications of our Chief Executive Officer and Chief Financial Officer as exhibits. This Form 10-K/A is limited in scope to the foregoing, and should be read in conjunction with the original Form 10-K and our other filings with the Securities and Exchange Commission.

The Financial Statements contained in Part II. Item 8 of the original Form 10-K as well as the Controls and Procedures contained in Part II. Item 9A(T) of the original Form 10-K are reproduced in this amendment, but this amendment does not reflect events occurring after the filing of the original Form 10-K or modify or update those disclosures affected by subsequent events. Except as described above, we have not modified or updated the disclosures or information presented in the original Form 10-K.

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Part II

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of

Virginia Electric and Power Company

Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion) and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, common shareholder s equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Virginia Electric and Power Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to our consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for fair value measurements in 2008 and uncertain tax positions in 2007.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 24, 2009

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Consolidated Statements of Income

Year Ended December 31, (millions)	2008	2007(1)	2006(1)
Operating Revenue	**$ 6,934**	$ 6,181	$ 5,603
Operating Expenses			
Electric fuel and energy purchases	**2,683**	2,361	2,233
Purchased electric capacity	**410**	429	453
Other energy-related commodity purchases	**24**	27	56
Other operations and maintenance:			
Affiliated suppliers	**399**	345	311
Other	**1,006**	1,052	868
Depreciation and amortization	**608**	568	536
Other taxes	**183**	173	163
Total operating expenses	**5,313**	4,955	4,620
Income from operations	**1,621**	1,226	983
Other income	**52**	55	75
Interest and related charges:			
Interest expense	**297**	274	266
Interest expense junior subordinated notes payable to affiliated trust	**12**	30	30
Total interest and related charges	**309**	304	296
Income from operations before income tax expense and extraordinary item	**1,364**	977	762
Income tax expense	**500**	371	284
Income from operations before extraordinary item	**864**	606	478
Extraordinary item(2)		(158)	
Net Income	**864**	448	478
Preferred dividends	**17**	16	16
Balance available for common stock	**$ 847**	$ 432	$ 462

(1) Our 2007 and 2006 Consolidated Statements of Income have been recast to reflect our revised derivative income statement classification policy described in Note 2 of our Consolidated Financial Statements.

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

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

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Consolidated Balance Sheets

At December 31, (millions)	2008	2007
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 27**	$ 49
Customer receivables (less allowance for doubtful accounts of $8 at both dates)	**940**	763
Affiliated receivables	**8**	53
Other receivables (less allowance for doubtful accounts of $7 and $9)	**74**	58
Inventories (average cost method):		
Materials and supplies	**275**	248
Fossil fuel	**272**	272
Prepayments	**28**	165
Regulatory assets	**212**	
Other	**75**	92
Total current assets	**1,911**	1,700
Investments		
Nuclear decommissioning trust funds	**1,053**	1,339
Other	**3**	16
Total investments	**1,056**	1,355
Property, Plant and Equipment		
Property, plant and equipment	**23,476**	21,838
Accumulated depreciation and amortization	**(8,915)**	(8,702)
Total property, plant and equipment, net	**14,561**	13,136
Deferred Charges and Other Assets		
Intangible assets	**210**	176
Regulatory assets	**921**	564
Other	**143**	132
Total deferred charges and other assets	**1,274**	872
Total assets	**$ 18,802**	$ 17,063

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At December 31, (millions)	2008	2007
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 125**	$ 286
Short-term debt	**297**	257
Accounts payable	**436**	573
Payables to affiliates	**132**	80
Affiliated current borrowings	**417**	114
Accrued interest, payroll and taxes	**236**	234
Customer deposits	**116**	116
Other	**270**	123
Total current liabilities	**2,029**	1,783
Long-Term Debt		
Long-term debt	**6,000**	4,904
Junior subordinated notes payable to affiliated trust		412
Total long-term debt	**6,000**	5,316
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,485**	2,237
Asset retirement obligations	**715**	678
Regulatory liabilities	**760**	1,009
Other	**282**	242
Total deferred credits and other liabilities	**4,242**	4,166
Total liabilities	**12,271**	11,265
Commitments and Contingencies (see Note 20)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder s Equity		
Common stock no par[(1)]	**3,738**	3,388
Other paid-in capital	**1,110**	1,109
Retained earnings	**1,421**	1,015
Accumulated other comprehensive income	**5**	29
Total common shareholder s equity	**6,274**	5,541
Total liabilities and shareholder s equity	**$ 18,802**	$ 17,063

(1) 300,000 shares authorized, 209,833 shares and 198,047 shares outstanding at December 31, 2008 and 2007, respectively.
The accompanying notes are an integral part of our Consolidated Financial Statements.

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Consolidated Statements of Common Shareholder s Equity

(millions, except for shares)	Common Stock Shares (thousands)	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2005	198	$ 3,388	$ 886	$ 842	$ 117	$ 5,233
Net income				478		478
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(365)		(365)
Other comprehensive income, net of tax					45	45
Balance at December 31, 2006	198	3,388	887	955	162	5,392
Net income				448		448
Equity contribution by parent			220			220
Tax benefit from stock awards and stock options exercised			2			2
Dividends				(393)		(393)
Adoption of FIN 48				5		5
Other comprehensive loss, net of tax					(133)	(133)
Balance at December 31, 2007	198	3,388	1,109	1,015	29	5,541
Net income				**864**		**864**
Issuance of stock to parent	**12**	**350**				**350**
Tax benefit from stock awards and stock options exercised			**1**			**1**
Dividends				**(458)**		**(458)**
Other comprehensive loss, net of tax					**(24)**	**(24)**
Balance at December 31, 2008	**210**	**$ 3,738**	**$ 1,110**	**$ 1,421**	**$ 5**	**$ 6,274**

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

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Consolidated Statements of Comprehensive Income

Year Ended December 31, (millions)	**2008**	2007	2006
Net income	**$ 864**	$ 448	$ 478
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives hedging activities, net of $1, $1 and $6 tax	**(2)**	(1)	(10)
Changes in unrealized gains on nuclear decommissioning trust funds, net of $17, $80 and $(40) tax	**(29)**	(125)	62
Amounts reclassified to net income:			
Net realized (gains) losses on nuclear decommissioning trust funds, net of $(5), $2 and $7 tax	**8**	(3)	(9)
Net derivative (gains) losses-hedging activities, net of $1, $2 and $(2) tax	**(1)**	(4)	2
Other comprehensive income (loss)	**(24)**	(133)	45
Comprehensive income	**$ 840**	$ 315	$ 523

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

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Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	**2008**	2007	2006
Operating Activities			
Net income	**$ 864**	$ 448	$ 478
Adjustments to reconcile net income to net cash from operating activities:			
Net change in realized and unrealized derivative (gains) losses	**10**	(67)	(2)
Depreciation and amortization	**702**	654	619
Deferred income taxes and investment tax credits, net	**304**	256	24
Extraordinary item, net of income taxes		158	
Gain on sale of emissions allowances held for consumption	**(31)**	(19)	(74)
Other adjustments	**(15)**	(39)	(27)
Changes in:			
Accounts receivable	**(205)**	(77)	30
Affiliated accounts receivable and payable	**51**	(17)	6
Deferred fuel expenses, net	**(423)**	(315)	99
Inventories	**(27)**	(15)	(62)
Prepayments	**137**	(35)	(42)
Accounts payable	**(131)**	165	1
Accrued interest, payroll and taxes	**2**	7	(61)
Other operating assets and liabilities	**(3)**	112	91
Net cash provided by operating activities	**1,235**	1,216	1,080
Investing Activities			
Plant construction and other property additions	**(1,902)**	(1,184)	(925)
Purchases of nuclear fuel	**(135)**	(111)	(122)
Purchases of securities	**(455)**	(551)	(550)
Proceeds from sales of securities	**410**	520	533
Proceeds from sales of emissions allowances held for consumption	**45**	9	75
Other	**34**	11	29
Net cash used in investing activities	**(2,003)**	(1,306)	(960)
Financing Activities			
Issuance (repayment) of short-term debt, net	**40**	(361)	(287)
Issuance (repayment) of affiliated current borrowings, net	**653**	(26)	129
Issuance of long-term debt	**1,490**	2,250	1,000
Repayment of long-term debt	**(553)**	(1,335)	(624)
Repayment of affiliated notes payable	**(412)**		
Common dividend payments	**(441)**	(377)	(349)
Preferred dividend payments	**(17)**	(16)	(16)
Other	**(14)**	(14)	(9)
Net cash provided by (used in) financing activities	**746**	121	(156)
Increase (decrease) in cash and cash equivalents	**(22)**	31	(36)
Cash and cash equivalents at beginning of year	**49**	18	54
Cash and cash equivalents at end of year	**$ 27**	$ 49	$ 18
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 320**	$ 305	$ 254
Income taxes	**48**	211	419
Significant noncash investing and financing activities[1]:			
Accrued capital expenditures	**114**		
Conversion of short-term and long-term borrowings payable to parent to equity	**350**	220	

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

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Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2008, we served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. We are a member of PJM, an RTO, and our electric transmission facilities are integrated into the PJM wholesale electricity markets. All of our common stock is owned by our parent company, Dominion.

We manage our daily operations through two primary operating segments: DVP and Generation. In addition, we also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. Our assets remain wholly owned by us and our legal subsidiaries.

The terms 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, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power, including our Virginia and North Carolina operations and our consolidated subsidiaries.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

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 revenue and expenses for the periods presented. Actual results may differ from those estimates.

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

In accordance with GAAP, we report certain contracts and instruments at fair value. See Note 6 for further information on fair value measurements in accordance with SFAS No. 157.

Certain amounts in our 2007 and 2006 Consolidated Financial Statements and footnotes have been recast to conform to the 2008 presentation. See Note 3 for discussion of the recast of our 2007 Consolidated Balance Sheet due to the adoption of FSP FIN 39-1, *Amendment of FIN* 39, *Offsetting of Amounts Related to Certain Contracts*. Additionally, in the fourth quarter of 2008, we revised our derivative income statement classification policy, described in *Derivative Instruments*, to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. This includes unrealized changes in the fair value of and settlements of financially-settled derivatives not held for trading purposes, as well as gains or losses attributable to ineffectiveness, changes in the time value of options, and discontinuances of hedging instruments, which were previously presented in other operations and maintenance expense on a net basis. Our prior year Consolidated Statements of Income have

been recast to conform to the 2008 presentation; however, this had no impact on earnings.

Reapplication of SFAS No. 71

In March 1999, we discontinued the application of SFAS No. 71 to the majority of our generation operations upon the enactment of deregulation legislation in Virginia. Our 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 returned the Virginia jurisdiction of our 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. In connection with the reapplication of SFAS No. 71 to those operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed here, the overall impact of these changes was not material to our results of operations or financial condition in 2007. These policy changes are discussed further in *Derivative Instruments, Investments, Property, Plant and Equipment* and *Asset Retirement Obligations.*

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our 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 AOCI, related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer receivables at December 31, 2008 and 2007 included $341 million and $270 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to our customers. We estimate unbilled revenue based on historical usage, applicable customer rates, weather factors and total daily electric generation supplied after adjusting for estimated losses of energy during transmission.

The primary types of sales and service activities reported as operating revenue are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of excess generation sold at market-based rates, miscellaneous service revenue from electric distribution operations and other miscellaneous revenue. Other revenue accounted for less than ten percent of operating revenue in 2008, 2007 and 2006.

Electric Fuel and Purchased Energy Deferred Costs

Where permitted by regulatory authorities, the differences

Notes to Consolidated Financial Statements, Continued

between actual electric fuel and purchased energy expenses and the related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

For electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were fixed until July 1, 2007. Effective July 1, 2007 and 2008, the fuel factor was adjusted as discussed under *Virginia Fuel Expenses* in Note 20. Of the cost of fuel used in electric generation and energy purchases to serve utility customers approximately 82% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Income Taxes

We file a consolidated federal income tax return and participate in an intercompany tax sharing agreement with Dominion and its subsidiaries. In addition, where applicable, we file combined income tax returns with Dominion and its subsidiaries in various states; otherwise, we file separate state income tax returns. Our current income taxes are based on our taxable income or loss, determined on a separate company basis.

SFAS No. 109, *Accounting for Income Taxes*, requires an asset and liability approach to accounting for income taxes. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We establish a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Where permitted by regulatory authorities, the treatment of temporary differences may differ from the requirements of SFAS No. 109. Accordingly, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities.

Effective January 1, 2007, we adopted FIN 48. In our financial statements, we recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If we conclude that it is more-likely-than-not that a tax position, or some portion thereof, will not be sustained, the related tax benefits are not recognized in the financial statements. 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 may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in accrued interest, payroll and taxes, except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities in prepayments.

Prior to the adoption of FIN 48, we established liabilities for tax-related contingencies when the incurrence of the liability was

determined to be probable and the amount could be reasonably estimated in accordance with SFAS No. 5*,* and reviewed them in light of changing facts and circumstances.

We recognize changes in estimated interest payable on net underpayments and overpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. In our Consolidated Statements of Income for 2008, 2007 and 2006, we recognized reductions of interest expense of $4 million, $6 million and $1 million, respectively, and no penalties. At December 31, 2008, we had accrued $9 million for interest receivable and $2 million for interest payable and penalties. At December 31, 2007, we had accrued $5 million for interest receivable and $2 million for interest payable and penalties.

Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits.

At December 31, 2008, our Consolidated Balance Sheet included $3 million of prepaid state income taxes (recorded in prepayments), $6 million of federal and state income taxes payable (recorded in accrued interest, payroll and taxes) and $106 million of federal and state income taxes payable (recorded in deferred credits and other liabilities). At December 31, 2007, our Consolidated Balance Sheet included $136 million of prepaid federal and state income taxes (recorded in prepayments), $106 million of federal and state income taxes payable (recorded in deferred credits and other liabilities) and a $33 million receivable from Dominion for tax refunds (recorded in affiliated receivables).

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2008 and 2007, accounts payable included $23 million and $31 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

We use derivative instruments such as futures, swaps, forwards, options and FTRs to manage the commodity, currency exchange, and financial market risks of our business operations.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires all derivatives, except those for which an exception applies, to be reported in our Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting normal purchases and normal sales may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

To manage price risk, we hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent we do not hold offsetting positions for such derivatives, we believe these instruments represent economic hedges that mitigate our exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

All income statement activity, including amounts realized upon settlement, for derivative contracts are presented in operating revenue, operating expense or interest and related charges based on the nature of the underlying risk. As previously discussed, under our former derivative income statement classification policy, this activity was presented in other operations and maintenance expense on a net basis. Following the revision of this policy in the fourth quarter of 2008, our prior year Consolidated Statements of Income were recast to conform to the 2008 presentation.

We generally recognize revenue or expense from all non-derivative energy-related contracts on a gross basis at the time of contract performance, settlement or termination.

Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings.

Derivative Instruments Designated as Hedging Instruments

We designate certain derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, we formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. We assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, we exclude certain gains or losses on hedging instruments from the measurement of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. We discontinue hedge accounting prospectively for derivatives that cease to be highly effective hedges.

Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

Cash Flow Hedges A portion of our hedge strategies represents cash flow hedges of the variable price risk associated with the purchase of natural gas, electricity and other energy-related products. We also use foreign currency forward and option contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are

reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. We reclassify derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable.

Fair Value Hedges We use designated interest rate swaps as fair value hedges on certain fixed-rate long-term debt to manage our interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value. We reclassify derivative gains and losses from the hedged item to earnings when the hedged item is included in earnings, or earlier, if the hedged item no longer qualifies for hedge accounting. For fair value hedge transactions, we discontinue hedge accounting if the hedged item no longer qualifies for hedge accounting.

See Note 6 for further information about fair value measurements and associated valuation methods for derivatives under SFAS No. 157.

Investments

Marketable Equity and Debt Securities

We account for and classify investments in marketable equity and debt securities held by our nuclear decommissioning trusts as available-for-sale securities. These investments are reported at fair value in nuclear decommissioning trust funds in our Consolidated Balance Sheets. Upon reapplication of SFAS No. 71 in April 2007 for our utility generation operations, net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in our utility nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. We continue to report realized gains and losses (including any other-than-temporary impairments) for jurisdictions that are not subject to cost-based regulation in other income and unrealized gains as a component of AOCI, net of tax.

In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

Non-Marketable Investments

We account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Our non-marketable investments include:

- *Equity method investments* when we have the ability to exercise significant influence, but not control, over the investee. These investments are recorded in investments in other investments in our Consolidated Balance Sheets. We record equity method adjustments in other income in our Consolidated Statements of Income including: our proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, and other adjustments required by the equity method.

- *Cost method investments* when we do not have the ability to exercise significant influence over the investee. These

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investments are included in other investments and nuclear decommissioning trust funds.

Other Than Temporary Impairment

We periodically review our investments to determine whether a decline in fair value should be considered other than temporary. We use several criteria to evaluate other-than-temporary declines, including the length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its cost and the expected fair value of the security. If a decline in fair value of any security is determined to be other than temporary, the security is written down to its fair value at the end of the reporting period. Our method of assessing other-than- temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since we have limited ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments, we do not have the ability to hold individual securities in the trusts through an anticipated recovery period. Accordingly, we consider all securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than temporarily impaired.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, consisting of labor, materials, and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred.

In 2008, 2007 and 2006, we capitalized interest costs and AFUDC of $21 million, $27 million and $21 million to property, plant and equipment, respectively. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations in April 2007, we discontinued capitalizing interest on generation-related construction projects since the Virginia Commission previously allowed for current recovery of construction financing costs. Under current Virginia legislation, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset prior to implementation of the rate adjustment clause and is not capitalized to property, plant and equipment. In 2008 and 2007, we recorded $18 million and $1 million of AFUDC related to these projects, respectively.

For property subject to cost-of-service rate regulation, including electric distribution, electric transmission and utility generation property effective April 2007, the undepreciated cost of such property, less salvage value, is charged to accumulated depreciation at retirement with gains and losses recorded on sales of property. Cost of removal collections from utility customers and expenditures not representing AROs are recorded as regulatory liabilities.

For property that is not subject to cost-of-service rate regulation, including utility generation property prior to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our utility generation operations in April 2007, cost of removal not

associated with AROs is charged to expense as incurred. We also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property s net book value at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. Our depreciation rates on utility property, plant and equipment are as follows:

Year Ended December 31,	**2008**	2007	2006
(percent)			
Generation[1]	**2.60**	2.24	2.07
Transmission	**2.03**	1.98	1.97
Distribution	**3.37**	3.38	3.45
General and other	**3.97**	4.57	4.93

(1) In October 2007, we revised the depreciation rates for our generation assets to reflect the results of a new depreciation study, which incorporates the property, plant and equipment accounting policy changes that were made upon the reapplication of SFAS No. 71 as well as updates to other assumptions. This change increased annual depreciation expense by approximately $54 million ($33 million after tax).

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis. We report the amortization of nuclear fuel in electric fuel and energy purchases expense in our Consolidated Statements of Income and in depreciation and amortization in our Consolidated Statements of Cash Flows.

Emissions Allowances

Emissions allowances are issued by the EPA and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including SO_2 and NO_X. Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation operations are held primarily for consumption and are classified as intangible assets in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances. Allowances issued directly to us by the EPA are carried at zero cost.

Emissions allowances are amortized in the periods the emissions are generated, with the amortization reflected in depreciation and amortization expense in our Consolidated Statements of Income. We report purchases and sales of these allowances as investing activities in our Consolidated Statements of Cash Flows and gains or losses resulting from sales in other operations and maintenance expense in our Consolidated Statements of Income.

Impairment of Long-Lived and Intangible Assets

We perform an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount.

Regulatory Assets and Liabilities

For utility operations subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulator.

Asset Retirement Obligations

We recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed. These amounts are capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, we estimate fair value using discounted cash flow analyses. With the reapplication of SFAS No. 71 for the Virginia jurisdiction of our generation operations in April 2007, we now report accretion of the AROs associated with nuclear decommissioning due to the passage of time as an adjustment to the related regulatory liability for certain jurisdictions. Previously, we reported such expense in other operations and maintenance expense in our Consolidated Statements of Income. We report accretion of all other AROs in other operations and maintenance expense in our Consolidated Statements of Income.

Amortization of Debt Issuance Costs

We defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation have also been deferred and are amortized over the lives of the new issues.

NOTE 3. NEWLY ADOPTED ACCOUNTING STANDARDS

2008

SFAS No. 157

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

Generally, the provisions of this statement are applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application was required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk*

Management Activities, and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*. Retrospective application did not result in a cumulative effect of accounting change in retained earnings as of January 1, 2008.

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

No. 157.

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

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

See Note 6 for further information on fair value measurements in accordance with SFAS No. 157.

SFAS No. 159

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

FSP FIN 39-1

The provisions of FSP FIN 39-1 became effective for us beginning January 1, 2008. FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the

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same counterparty under the same master netting arrangement. Upon our adoption of FSP FIN 39-1, we revised our accounting policy to no longer offset fair value amounts recognized for certain derivative instruments and recast our prior year Consolidated Balance Sheet in order to retrospectively apply the standard. The adoption of FSP FIN 39-1 resulted in a $6 million increase in both Other current assets and Other current liabilities as of December 31, 2007. FSP FIN 39-1 also requires disclosures related to our cash collateral, for which we had recorded margin assets of $18 million and margin liabilities of $4 million at December 31, 2008. The adoption of FSP FIN 39-1 had no impact on our results of operations or cash flows.

FSP FAS 140-4 AND FIN 46R-8

The provisions of FSP FIN FAS 140-4 and FIN 46R-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interests Entities*, became effective for us for the year ended December 31, 2008. This FSP amends FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, to require public entities to provide additional disclosures about transfers of financial assets. It also amends FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, to require public enterprises to provide additional disclosures about their involvement with variable interest entities. The provisions of FSP FIN FAS 140-4 and FIN 46R-8 have not impacted our results of operations or financial condition.

2007

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recorded a $5 million benefit, primarily attributable to interest, to beginning retained earnings for the cumulative effect of the change in accounting principle. As of January 1, 2007, our unrecognized tax benefits totaled $225 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.

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 and reports as revenue 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. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*. SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed

and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. SFAS No. 141R amends SFAS No. 109*,* to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties and acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. The provisions of SFAS No. 141R became effective for us on January 1, 2009.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*. SFAS No. 161 requires enhancements to disclosures regarding derivative instruments and hedging activities accounted for under SFAS No. 133. The enhancements include additional disclosures regarding the reasons derivative instruments are used, how they are used, how these instruments and their related hedged items are accounted for under SFAS No. 133, as well as the impact of these derivative instruments on an entity s results of operations, financial condition and cash flows. In addition, SFAS No. 161 requires the disclosure of the fair values of derivative instruments, and associated gains and losses in a tabular format and information about derivative features that are credit-risk related. The provisions of SFAS No. 161 will become effective for disclosures in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

NOTE 5. INCOME TAXES

Details of income tax expense were as follows:

Year Ended December 31,	**2008**	2007	2006
(millions)			
Current expense:			
Federal	**$ 158**	$ 152	$ 213
State	**37**	(37)	47
Total current	**195**	115	260
Deferred expense:			
Federal	**279**	163	29
State	**30**	103	10
Total deferred	**309**	266	39
Amortization of deferred investment tax credits	**(4)**	(10)	(15)
Total income tax expense	**$ 500**	$ 371	$ 284

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The statutory U.S. federal income tax rate reconciles to our effective income tax rates as follows:

Year Ended December 31,	**2008**	2007	2006
U.S statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
State income tax, net of federal tax benefit	**3.6**	4.4	4.8
Amortization of investment tax credits	**(0.3)**	(0.8)	(1.5)
Domestic production activities deduction	**(0.5)**	(0.2)	
AFUDC equity	**(0.5)**	(0.5)	(0.3)
Legislative changes	**(0.4)**		
Employee benefits	**(0.2)**	(0.3)	(0.2)
Other, net		0.4	(0.5)
Effective tax rate	**36.7%**	38.0%	37.3%

As the result of West Virginia income tax rate reductions enacted in March 2008, to be phased in during the period 2009 through 2014, we reduced our net deferred tax liabilities by $6 million.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Our net deferred income taxes consist of the following:

As of December 31,	**2008**	2007
(millions)		
Deferred income taxes:		
Total deferred income tax assets	**$ 394**	$ 643
Total deferred income tax liabilities	**2,875**	2,824
Total net deferred income tax liabilities	**$ 2,481**	$ 2,181
Total deferred income taxes:		
Depreciation method and plant basis differences	**$ 2,087**	$ 1,980
Deferred state income taxes	**214**	185
Deferred fuel	**313**	151
Other	**(133)**	(135)
Total net deferred income tax liabilities	**$ 2,481**	$ 2,181

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. We are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material.

Prior to 2007, we established liabilities for income tax-related contingencies when we believed that it was probable that a liability had been incurred and the amount could be reasonably estimated and subsequently reviewed them in light of changing facts and circumstances.

With the adoption of FIN 48, effective January 1, 2007, we recognize in the financial statements only those positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position and any portion of the related tax benefit is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. These unrecognized tax benefits may impact the financial statements by increasing taxes payable, reducing tax

refunds receivable or changing deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities.

A reconciliation of changes in our unrecognized tax benefits follows:

(millions)	**2008**	2007
Balance at January 1,	**$ 195**	$ 225
Increases prior period positions	**20**	20
Decreases prior period positions	**(22)**	(36)
Current period positions	**20**	15
Prior period positions becoming otherwise deductible in current period	**(11)**	(13)
Settlement with tax authorities	**(22)**	(16)
Balance at December 31,	**$ 180**	$ 195

Unrecognized tax benefits that, if recognized, would affect the effective tax rate were $21 million and $8 million at December 31, 2008 and 2007, respectively, and $5 million at January 1, 2007. As the result of not recognizing these tax benefits, income tax expense increased by $13 million and $3 million in 2008 and 2007, respectively.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. 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 would otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued until the period in which the amounts would become deductible.

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 pursue refunds related to certain deductions for the years 1995 through 1998.

In 2007, the U.S. Congressional Joint Committee on Taxation completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1993 through 1998. In October of 2007, we received a tax refund of approximately $33 million for 1993 through 1997. Due to carryback adjustments, the tax refund of $5 million for 1998 will not be received until tax years 1999 through 2001 have been settled and reviewed by the Joint Committee. The refund will have no impact on our earnings.

We have reached a settlement with IRS Appeals regarding certain adjustments proposed during the examination of tax years 1999 through 2001, except we have reserved the right to pursue refunds related to certain deductions. The settlement is being submitted to the Joint Committee for review. With the settlement and payment of resulting tax liabilities, our unrecognized tax benefits would be reduced by approximately $12 million with no impact on our earnings. In addition, we would be entitled to a refund of $41 million, representing amounts paid during the examination and appeals process related to the adjustments disputed in our protest filed with IRS Appeals. The refund will have no impact on our earnings.

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In 2007, the Internal Revenue Service (IRS) completed its examination of Dominion s 2002 and 2003 consolidated returns. We filed protests for certain proposed adjustments with IRS Appeals in July 2007, and Dominion is currently engaged in settlement negotiations with IRS Appeals regarding those adjustments. In addition, the IRS began its audit of tax years 2004 and 2005 in November 2007.

With our appeals of assessments received from tax authorities, including amounts related to the settlement negotiations with IRS Appeals for 2002 and 2003, we believe that it is reasonably possible that unrecognized tax benefits could decrease by $30 million to $70 million during 2009. The decrease would be the result of successful resolution of proposed adjustments through settlement negotiations or payments made to tax authorities. In addition, unrecognized tax benefits could be reduced by $13 million to recognize prior period amounts becoming otherwise deductible in the current period. Since the uncertainty for the majority of these unrecognized tax benefits involve only the timing of the deductions, we anticipate that the impact on earnings will be limited to revisions of our accrual for interest on tax underpayments and overpayments.

We are currently working with the IRS under its Pre-Filing Program (Program) to enter into an agreement regarding the calculation of our qualified production activities deduction. The objective of the Program is to provide taxpayers with greater certainty regarding a specific issue at an earlier point in time than can be attained under the normal post-filing examination process. If we are able to enter into an agreement with the IRS in 2009 that eliminates or reduces uncertainty about the deduction, it is reasonably possible that our unrecognized tax benefits as of December 31, 2008, could decrease by $5 million to $10 million, which would be reflected in our 2009 earnings.

Otherwise, with regard to tax years 2004 through 2008, we cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2009.

Virginia Power is included in Dominion s combined state income tax returns. The returns filed with Virginia for 2005 and subsequent years remain subject to examination. We are also obligated to report adjustments resulting from IRS settlements of earlier years to state tax authorities. In addition, if we utilize state net operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are subject to examination by state tax authorities.

In February 2009, the President of the U.S. signed into law the American Recovery and Reinvestment Act of 2009 (the Act). The Act includes provisions to stimulate economic growth, including incentives for increased capital investment by businesses and incentives to promote renewable energy. We are currently evaluating the Act but have not yet determined its impact on our future results of operations, cash flows or financial condition.

NOTE 6. FAIR VALUE MEASUREMENTS

As described in Note 3, we adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, SFAS No. 157 permits the

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

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

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

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

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

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

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 consist of long-dated commodity derivatives, FTRs, and other modeled commodity derivatives.

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

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to the length of time to settlement and absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from PJM auctions, which is accurate for day-one valuation, but generally is not considered to be representative of the ultimate settlement values. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

As of December 31, 2008, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $69 million. A hypothetical 10% increase in commodity prices would decrease the net liability by $3 million, while a hypothetical 10% decrease in commodity prices would increase the net liability by $3 million.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions, as of December 31, 2008:

(millions)	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives	**$**	**$ 60**	**$ 7**	**$ 67**
Investments	**225**	**714**		**939**
Total assets	**$ 225**	**$ 774**	**$ 7**	**$ 1,006**
Liabilities:				
Derivatives	**$**	**$ 23**	**$ 76**	**$ 99**

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the year ended December 31, 2008:

(millions)	Derivatives [1]
Year Ended December 31, 2008	
Balance at January 1, 2008	**$ (4)**
Total realized and unrealized gains or (losses):	
Included in earnings	**(27)**
Included in other comprehensive income (loss)	
Included in regulatory and other assets/liabilities	**(59)**
Purchases, issuances and settlements	**21**
Transfers out of Level 3	

Balance at December 31, 2008	$	(69)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	$	(5)

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

The gains and losses included in earnings in the Level 3 fair value category, including those attributable to the change in unrealized gains and losses relating to assets still held at the reporting date, were classified in Electric Fuel and Energy Purchases expense in our Consolidated Statement of Income for the year ended December 31, 2008.

Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. At December 31, 2008 and 2007, the carrying amount of our cash and cash equivalents, customer and other receivables, short-term debt and accounts payable are representative of fair value because of the short-term nature of these instruments. The financial instruments carrying amounts and fair values are as follows:

At December 31,	**2008**		2007	
(millions)	**Carrying Amount**	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
Long-term debt(2)	**$ 6,125**	**$ 6,231**	$ 5,190	$ 5,209
Junior subordinated notes payable to affiliated trust			412	402
Preferred stock(3)	**257**	**231**	257	257

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. The carrying amount of debt issues with short- term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Includes securities due within one year and amounts which represent the unamortized discount and premium. Also includes the valuation of certain fair value hedges associated with our fixed rate debt of $1 million at December 31, 2008.

(3) Includes issuance expenses of $2 million at December 31, 2008 and 2007.

NOTE 7. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products, as well as currency exchange and interest rate risks of our business

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operations. We use derivative instruments to manage our exposure to these risks and designate derivative instruments as cash flow or fair value hedges for accounting purposes as allowed by SFAS No. 133. As discussed in Note 2, for jurisdictions subject to cost-based regulation, changes in the fair value of derivatives designated as hedges are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings.

For the years ended December 31, 2008, 2007 and 2006, gains or losses on hedging instruments determined to be ineffective and excluded from the measurement of effectiveness were not material. Amounts excluded from the measurement of ineffectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2008:

(millions)	AOCI After Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After Tax	Maximum Term
Electric capacity	**$ 5**	**$ 3**	**41 months**
Other	**(1)**	**(2)**	**360 months**
Total	**$ 4**	**$ 1**	

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

NOTE 8. INVESTMENTS

Marketable Equity and Debt Securities

We hold marketable equity and debt securities and cash equivalents in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds, as of December 31, 2008 and 2007, are summarized below. There were no unrealized losses included in AOCI as of December 31, 2008 or 2007.

	Fair	Total

(millions)	Value	Unrealized Gains
2008		
Equity securities	**$ 468**	**$ 9**
Debt securities	**460**	**17**
Cash equivalents and other	**17**	
Total	**$ 945**	**$ 26(1)**
2007		
Equity securities	$ 844	$ 245
Debt securities	468	13
Cash equivalents and other	27	
Total	$ 1,339	$ 258(1)

(1) Included in AOCI and the decommissioning trust regulatory liability as discussed in Note 2.

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2008 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	**$ 27**
Due after one year through five years	**113**
Due after five years through ten years	**153**
Due after ten years	**167**
Total	**$ 460**

Gross realized gains on our available-for-sale securities totaled $45 million, $52 million and $49 million in 2008, 2007 and 2006, respectively, and gross realized losses totaled $143 million, $52 million and $33 million in 2008, 2007 and 2006, respectively. Gross realized gains and losses for 2008 and 2007 include amounts recorded to a regulatory liability as discussed in Note 2. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

Cost-Method Investments

At December 31, 2008, the carrying value of our cost-method investments totaled $108 million, which approximated their estimated fair value. We did not have any significant cost-method investments at December 31, 2007.

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Major classes of property, plant and equipment and their respective balances are:

At December 31, (millions)	**2008**	2007
Utility:		
Generation	**$ 10,949**	$ 10,237
Transmission	**2,116**	1,942
Distribution	**7,250**	6,931
Nuclear fuel	**943**	930
General and other	**562**	591
Other including plant under construction	**1,648**	1,200
Total utility	**23,468**	21,831
Nonutility other	**8**	7

Total property, plant and equipment	**$ 23,476**	$ 21,838

Jointly-Owned Plants

Our proportionate share of jointly-owned plants at December 31, 2008 is as follows:

(millions, except percentages)	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
Ownership interest	**60.0%**	**88.4%**	**50.0%**
Plant in service	**$ 1,011**	**$ 2,107**	**$ 560**
Accumulated depreciation	**(427)**	**(1,028)**	**(155)**
Nuclear fuel		**436**	
Accumulated amortization of nuclear fuel		**(343)**	
Other including plant under construction	**9**	**154**	**1**

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The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly-owned facilities in the same proportion as their respective ownership interest. We report our share of operating costs in the appropriate operating expense (electric fuel and energy purchases, other operations and maintenance, depreciation and amortization and other taxes, etc.) in our Consolidated Statements of Income.

NOTE 10. INTANGIBLE ASSETS

All of our intangible assets are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $28 million, $46 million and $37 million for 2008, 2007 and 2006, respectively. In 2008, we acquired $22 million of intangible assets, primarily representing software and emissions allowances, with an estimated weighted-average amortization period of 6.55 and 8.19 years, respectively. The components of our intangible assets are as follows:

At December 31,		**2008**		2007
(millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Software and software licenses	**$ 261**	**$ 157**	$ 240	$ 165
Emissions allowances	**72**	**4**	75	15
Other	**51**	**13**	53	12
Total	**$ 384**	**$ 174**	$ 368	$ 192

Annual amortization expense for these intangible assets is estimated to be $27 million for 2009, $29 million for 2010, $17 million for 2011, $12 million for 2012 and $6 million for 2013.

NOTE 11. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	**2008**	2007
(millions)		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	**$ 133**	$
Derivatives(2)	**79**	
Regulatory assets current	**212**	
Deferred cost of fuel used in electric generation(1)	**676**	386
RTO start-up costs and administration fees(3)	**122**	95
Income taxes recoverable through future rates(4)	**35**	30

AFUDC(5)	**19**	1
Termination of certain power purchase agreements(6)	**18**	20
Other	**51**	32
Regulatory assets non-current	**921**	564
Total regulatory assets	**$ 1,133**	$ 564
Regulatory liabilities:		
Provision for future cost of removal(7)	**$ 506**	$ 453
Decommissioning trust(8)	**213**	487
Other(9)	**61**	69
Total regulatory liabilities	**$ 780**	$ 1,009

(1) As discussed under Virginia Fuel Expenses in Note 20, in June 2007, the Virginia Commission approved a fuel factor increase of approximately $219 million, effective July 1, 2007 with the balance of approximately $443 million to be deferred and subsequently recovered, without interest, during the period commencing July 1, 2008 and ending June 30, 2011. Beginning July 1, 2008 the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance commenced, with the balance to be recovered in subsequent periods as provided by Virginia law.

(2) As discussed under Derivative Instruments in Note 2 for jurisdictions subject to cost-based regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers, without interest.

(3) The FERC has approved our recovery of start-up costs incurred in connection with joining an RTO and on-going administrative charges paid to PJM through a DRC. We have deferred $97 million in start-up costs and administrative charges and $25 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence on the effective date of approval by the Virginia Commission of a rate adjustment clause designed to recover retail transmission costs as authorized under the 2007 Virginia Regulation Act.

(4) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes.

(5) Under current Virginia legislation, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset prior to implementation of the rate adjustment clause. The majority of this AFUDC is expected to be recovered through April 2012.

(6) The North Carolina Commission has authorized the deferral of previously incurred costs associated with the termination of certain long-term power purchase agreements with nonutility generators. The related costs are being amortized over the original term of each agreement.

(7) Rates charged to customers by our regulated business include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.

(8) Primarily reflects a regulatory liability established in 2007 representing amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143.

(9) Includes $20 million reported in other current liabilities in 2008.

At December 31, 2008, approximately $739 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs and the cost of terminating certain power purchase agreements.

NOTE 12. ASSET RETIREMENT OBLIGATIONS

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities. We also have AROs related to certain electric transmission and distribution assets located on property that we do not own and hydroelectric generation facilities. We currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets. Thus, AROs for these assets will not be reflected in our Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. Generally, this will occur when the expected retirement or abandonment dates are

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Notes to Consolidated Financial Statements, Continued

determined by our operational planning. The changes to our AROs during 2008 were as follows:

(millions)	Amount
AROs at December 31, 2007[1]	$ 679
Obligations settled during the period	**(1)**
Accretion	**38**
Other	**1**
AROs at December 31, 2008[1]	**$ 717**

(1) Includes $1 million and $2 million reported in other current liabilities at December 31, 2007 and 2008, respectively.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2008 and 2007, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.1 billion and $1.3 billion, respectively.

NOTE 13. VARIABLE INTEREST ENTITIES

FIN 46R addresses the consolidation of variable interest entities (VIEs). An entity is considered a VIE under FIN 46R if it does not have sufficient equity to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

- control through voting rights,
- the obligation to absorb expected losses, or
- the right to receive expected residual returns.

FIN 46R requires the primary beneficiary of a VIE to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that receives the majority of a VIE s expected losses, expected residual returns, or both.

We have long-term power and capacity contracts with four non-utility generators with an aggregate generation capacity of approximately 940 Mw. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that we consider to be variable interests. After an evaluation of the information provided to us by these entities, we were unable to determine whether they were VIEs. However, the information they provided, as well as our knowledge of generation facilities in Virginia, enabled us to conclude that, if they were VIEs, we would not be the primary beneficiary. This conclusion was based primarily on a qualitative assessment of our variable interests as compared to the operations, commodity price and other risks retained by the equity and debt holders during the remaining terms of our contracts and for the years the entities are expected to operate after our contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $1.9 billion as of December 31, 2008. We paid $205 million, $211 million and $214 million for electric capacity and $196 million, $160 million and $130 million for electric energy to these entities for the years ended December 31, 2008, 2007 and 2006, respectively.

We purchased shared services from DRS, an affiliated VIE, of approximately $397 million, $344 million and $310 million for

the years ended December 31, 2008, 2007 and 2006, respectively. We determined that we are not the most closely associated entity with DRS and therefore not the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to all

Dominion subsidiaries, including us. We have no obligation to absorb more than our allocated share of DRS costs.

NOTE 14. SHORT-TERM DEBT AND CREDIT AGREEMENTS

We use short-term debt, primarily commercial paper, to fund working capital requirements and as a bridge to long-term debt financing. The level of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations.

Our credit facility commitments are with a large consortium of banks, including Lehman. In September 2008, Lehman filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. At December 31, 2008, Lehman s total commitment to our credit facilities was less than six percent of the aggregate commitment from the consortium of banks. We do not believe that the potential reduction in available capacity under these credit facilities that could result from Lehman s bankruptcy will have a significant impact on our liquidity.

Excluding commitments provided by Lehman, our short-term financing is supported by a $2.8 billion five-year joint revolving credit facility with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and for other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

At December 31, 2008, total outstanding commercial paper supported by the joint credit facility was $297 million, all of which were our borrowings, with a weighted-average interest rate of 5.92%. At December 31, 2007, total outstanding commercial paper supported by the joint credit facility was $757 million, of which our borrowings were $257 million, with a weighted-average interest rate of 5.68%.

At December 31, 2008, total outstanding letters of credit supported by the joint credit facility were $187 million, of which less than $86 million were issued on our behalf. At December 31, 2007, total outstanding letters of credit supported by the joint credit facility were $229 million, of which less than $8 million were issued on our behalf.

At December 31, 2008, capacity available under the joint credit facility was approximately $2.4 billion.

In addition to the credit facility commitments of $2.8 billion disclosed above, we also have a $182 million five-year credit facility, excluding commitments provided by Lehman, that supports certain of our tax-exempt financings.

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NOTE 15. LONG-TERM DEBT

At December 31,	2008 Weighted-Average Coupon[1]	2008	2007
(millions, except percentages)			
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.73%, due 2008 to 2013	**4.87%**	**$ 1,230**	$ 1,350
5.25% to 8.875%, due 2015 to 2038	**6.37%**	**4,272**	2,985
Unsecured Callable and Puttable Enhanced Securities[SM], 4.10% due 2038[2]			225
Tax-Exempt Financings[3]:			
Variable rate, due 2008			60
Variable rates, due 2015 to 2027	**2.05%**	**119**	137
5.25% to 7.65%, due 2008 to 2010	**5.54%**	**112**	205
3.6% to 6.5%, due 2017 to 2035	**5.13%**	**393**	223
Notes Payable to Affiliates:			
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042[4]			412
		6,126	5,597
Fair value hedge valuation[5]		**1**	
Amounts due within one year[6]	**5.76%**	**(125)**	(286)
Unamortized discount and premium, net		**(2)**	5
Total long-term debt		**$ 6,000**	$ 5,316

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2008.
(2) On December 15, 2008, option holders did not exercise their rights to purchase and remarket the notes. As a result, the notes were redeemed at par plus accrued interest, and we recorded a $23 million benefit from the early redemption of these securities.
(3) These financings relate to certain pollution control equipment at our generating facilities. The variable rate tax-exempt financings are supported by a stand-alone $182 million five-year credit facility, excluding commitments provided by Lehman, that terminates in February 2011.
(4) On May 19, 2008, the notes were redeemed at par plus accrued and unpaid distributions.
(5) Represents the valuation of certain fair value hedges associated with our fixed rate debt.
(6) Includes approximately $1 million for fair value hedge valuation for 2008.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2008 were as follows:

	2009	2010	2011	2012	2013	Thereafter	Total
(millions)							
	$ 124	**$ 246**	**$ 15**	**$ 616**	**$ 418**	**$ 4,707**	**$ 6,126**

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2008, there were no events of default under our covenants.

Junior Subordinated Notes Payable to Affiliated Trust

In 2002, we established a subsidiary capital trust, Virginia Power Capital Trust II (trust), a finance subsidiary of which we held 100% of the voting interests. The trust sold 16 million 7.375% trust preferred securities for $400 million, representing preferred beneficial interests and 97% beneficial ownership in the assets held by the trust. In exchange for the $400 million realized from

the sale of the trust preferred securities and $12 million of common securities that represent the remaining 3% beneficial ownership interest in the assets held by the capital trust, we issued $412 million of 2002 7.375% junior subordinated notes (junior subordinated notes) due July 30, 2042. The junior subordinated notes constituted 100% of the trust s assets.

In May 2008, we repaid $412 million 7.375% unsecured Junior Subordinated Notes and redeemed all 16 million units of the $400 million 7.375% Virginia Power Capital Trust II preferred securities due July 30, 2042. These securities were redeemed at a price of $25 per preferred security plus accrued and unpaid distributions.

NOTE 16. PREFERRED STOCK

We are authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference, and had 2.59 million preferred shares outstanding as of December 31, 2008 and 2007. Upon involuntary liquidation, dissolution or winding-up of the Company, each share would be entitled to receive $100 plus accrued dividends. Dividends are cumulative.

Holders of the outstanding preferred stock are not entitled to voting rights, except under certain provisions of the amended and restated articles of incorporation and related provisions of Virginia law restricting corporate action, or upon default in dividends, or in special statutory proceedings and as required by Virginia law (such as mergers, consolidations, sales of assets, dissolution and changes in voting rights or priorities of preferred stock).

Presented below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2008:

Dividend	Issued and Outstanding Shares (thousands)	Entitled Per Share Upon Liquidation
$5.00	**107**	**$ 112.50**
4.04	**13**	**102.27**
4.20	**15**	**102.50**
4.12	**32**	**103.73**
4.80	**73**	**101.00**
7.05	**500**	**101.77**(1)
6.98	**600**	**101.75**(2)
Flex MMP 12/02, Series A	**1,250**	**100.00**(3)
Total	**2,590**	

(1) Through 7/31/2009; $101.41 commencing 8/1/2009; amounts decline in steps thereafter to $100.00 by 8/1/2013.
(2) Through 8/31/2009; $101.40 commencing 9/1/2009; amounts decline in steps thereafter to $100.00 by 9/1/2013.
(3) Dividend rate was 5.50% through 12/20/2007. Dividend rate is now 6.25% through 3/20/2011; after which, the rate will be determined according to periodic auctions for periods established by us at the time of the auction process.

NOTE 17. SHAREHOLDER S EQUITY

Common Shareholder s Equity

In December 2008, as approved by the Virginia Commission, we issued 11,786 shares of our common stock to Dominion reflecting the conversion of $350 million of short-term demand note borrowings from Dominion to equity.

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Other Paid-In Capital

In December 2007, we recorded contributed capital of $220 million reflecting the conversion of a $220 million note payable to Dominion to equity.

Accumulated Other Comprehensive Income

Presented in the table below is a summary of AOCI by component:

At December 31, (millions)	**2008**	2007
Net unrealized gains on derivatives hedging activities, net of $(3) and $(5) tax, respectively	**$ 4**	$ 7
Net unrealized gains on nuclear decommissioning trust funds, net of $(1) and $(14) tax, respectively	**1**	22
Total AOCI	**$ 5**	$ 29

NOTE 18. DIVIDEND RESTRICTIONS

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2008, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion at December 31, 2008.

NOTE 19. EMPLOYEE BENEFIT PLANS

We participate in a defined benefit pension plan sponsored by Dominion. Benefits payable under the plan are based primarily on years of service, age and the employee s compensation. As a participating employer, we are subject to Dominion s funding policy, which is to contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974 (ERISA). Our net periodic pension cost related to this plan was $32 million, $37 million and $63 million in 2008, 2007 and 2006, respectively. Employee compensation is the basis for determining our share of total pension costs. We did not contribute to the pension plan in 2008, 2007 or 2006.

We participate in plans that provide certain retiree health care and life insurance benefits to multiple Dominion subsidiaries. Annual employee premiums are based on several factors such as age, retirement date and years of service. Our net periodic benefit cost related to these plans was $33 million, $24 million and $37 million in 2008, 2007 and 2006, respectively. Employee headcount is the basis for determining our share of total benefit costs.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, we fund other postretirement benefit costs through a Voluntary Employees Beneficiary Association (VEBA). Our contributions to the VEBA were $15 million, $7 million and $24 million in 2008, 2007 and 2006, respectively. We expect to contribute $35 million to the VEBA in 2009.

Dominion holds investments in trusts to fund benefit payments for the employee pension and other postretirement benefit plans, in which our employees participate. Investment-related declines in these trusts, such as those experienced during 2008, will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that we will provide to Dominion for our share of employee benefit plan contributions.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $14 million, $12 million and $11 million were incurred in 2008, 2007 and 2006, respectively.

NOTE 20. COMMITMENTS AND CONTINGENCIES

As the result of issues generated in the ordinary course of business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. The ultimate outcome of such proceedings cannot be predicted at this time, however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2008, we had the following long-term commitments 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:

(millions)	2009	2010	2011	2012	2013	Thereafter	Total
Purchased electric capacity(1)	**$ 361**	**$ 350**	**$ 349**	**$ 354**	**$ 356**	**$ 1,499**	**$ 3,269**

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2008, the present value of our total commitment for capacity payments is $2.2 billion. Capacity payments totaled $379 million, $410 million and $437 million, and energy payments totaled $372 million, $360 million and $291 million for 2008, 2007, and 2006, respectively.

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. The lease agreements expire on various dates and certain of the leases are renewable and contain options to purchase the leased property. Payments under certain leases are escalated based on an index such as the Consumer Price Index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2008 are as follows:

(millions)	2009	2010	2011	2012	2013	Thereafter	Total
	$ 27	**$ 24**	**$ 20**	**$ 13**	**$ 9**	**$ 22**	**$ 115**

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Rental expense totaled $39 million, $37 million and $34 million for 2008, 2007 and 2006, respectively, the majority of which is reflected in other operations and maintenance expense.

Environmental Matters

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

Superfund Sites

From time to time, we may be identified as a PRP to a Superfund site. The EPA (or a state) can either (a) allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or (b) conduct the remedial investigation and action and then seek reimbursement from the parties. Each party can be held jointly, severally and strictly liable for all costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, we may be responsible for the costs of remedial investigation and actions under the Superfund Act or other laws or regulations regarding the remediation of waste. We do not believe that any currently identified sites will result in significant liabilities.

Nuclear Operations

Nuclear Decommissioning Minimum Financial Assurance

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2008 calculation for the NRC minimum financial assurance amount, aggregated for our nuclear units, was $1.5 billion and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we continue to believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for our Surry and North Anna units particularly when combined with ratepayer collections and contributions to the decommissioning trusts, if such future collections and contributions are required. This reflects our long-term investment horizon since the units will not be decommissioned for decades and our positive long-term outlook for trust fund investment returns. We will continue to monitor these trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

Nuclear Insurance

The Price-Anderson Act provides the public up to $12.5 billion of liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from commercial insurance pools with the remainder

provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to $118 million for each of our four licensed reactors, not to exceed $18 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion each for North Anna and Surry), exceeds the NRC s minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Our nuclear property insurance is provided by the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $49 million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

We purchase insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period s maximum assessment is $19 million.

ODEC, a part owner of North Anna, is responsible to us for its share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into a contract with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contract with the DOE. In January 2004, we filed a lawsuit in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for the Company in the amount of approximately $112 million for its spent-fuel related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U.S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

Litigation

We are co-owners with ODEC of the Clover power station. In 1989, we entered into a long term coal transportation agreement with Norfolk Southern Railway Company (Norfolk Southern) for the delivery of coal to the facility. The agreement specifies a base rate with adjustments tied to a published index. Norfolk Southern claimed in October 2003 that the parties to the agreement had employed an incorrect reference index since the agreement s inception to adjust the base transportation rate. In November 2003, we and ODEC filed suit against Norfolk Southern seeking to clarify the price adjustment provisions of the transportation agreement. The trial court ruled in Norfolk Southern s favor by

concluding that the agreement specifies the use of the index (NS Index) which Norfolk Southern claims should have been applied to adjust the base rate and which should be applied going forward. On September 1, 2006, the court entered an order directing us and ODEC to correct invoices from December 1, 2003 to the present by calculating rates using the NS Index as if it had been applied from the inception of the agreement, to tender the difference to Norfolk Southern with interest at the rate provided by the agreement and to pay future invoices using the NS Index as if it had been applied from the inception of the agreement.

In April 2008, issues regarding the amount of Norfolk Southern s claimed damages were tried, and the trial court issued a Final Order and Decree. The court assessed damages of approximately $78 million for the contract period from December 1, 2003 through November 30, 2007 and imposed prejudgment interest of approximately $9 million. If upheld, our share would be one-half of the total judgment, approximately $44 million. The court also ordered the Company and ODEC to calculate base rate adjustments using the NS Index for the remaining term of the agreement. Interest would be assessed on any difference between the amounts which we and ODEC pay to Norfolk Southern and the amounts which the court ordered to be paid. We believe the court s interpretation of the transportation agreement, and its ruling on other issues in the case, are legally incorrect. In July 2008, we and ODEC filed a petition for appeal of the trial court s order to the Supreme Court of Virginia and posted security to suspend execution of the judgment during the appeal. In January 2009, the Supreme Court of Virginia granted our petition for appeal. No liability has been recorded in our Consolidated Financial Statements related to this matter.

Guarantees and Surety Bonds

As of December 31, 2008, we had issued $16 million of guarantees primarily to support tax exempt debt issued through conduits. We had also purchased $109 million of surety bonds for various purposes, including providing workers compensation coverage. Under the terms of surety bonds, we are obligated to indemnify the respective surety bond company for any amounts paid.

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 December 31, 2008, 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.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Regulation Act) and the fuel factor statute became effective, which significantly changed electricity regulation in Virginia. Prior to the Regulation Act, our base rates in Virginia were to be capped at 1999 levels until December 31, 2010, at which time Virginia was to convert to retail competition for its electric supply service. The Regulation Act ended capped rates two years early, on December 31, 2008, at which time retail competition would be available only to individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will also be permitted to purchase renewable energy from competitive suppliers if their incumbent electric utility does not offer a 100% renewable energy tariff.

Pursuant to the Regulation Act, the Virginia Commission entered an order in January 2009 initiating reviews of the base rates and terms and conditions of all investor-owned utilities in Virginia. The Company must submit its filing and accompanying schedules on or before April 1, 2009, and it anticipates that its filing will support an increase in base rates. The ROE in that rate review will be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. Possible outcomes of the 2009 rate review, according to the Regulation Act, include a rate increase, a rate decrease, and a refund of earnings more than 50 basis points above the authorized ROE. We are unable to predict the outcome of future rate actions at this time. However, an unfavorable outcome could adversely affect our results of operations, financial condition and cash flows.

After the 2009 rate review, the Virginia Commission will conduct biennial reviews of our rates, terms and conditions beginning in 2011. As in the 2009 rate review, our ROE in the biennial reviews can be no lower than that reported by not less than a majority of comparable utilities within the southeastern U.S., with certain limitations, as described in the Act. The Commission shall be authorized to increase our base rates if our earnings are more than 50 basis points below the authorized level.

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If our earnings are more than 50 basis points above the authorized level, such earnings will be shared with customers. If over-earning persists for two consecutive biennial periods, in addition to earnings sharing, rates may also be reduced.

Separate from base rates, the Regulation Act also authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, environmental compliance, FERC-approved transmission costs, conservation and energy efficiency programs, and renewables programs. The Act also provided for enhanced returns on capital expenditures on specific new generation projects, including but not limited to nuclear generation, clean coal/carbon capture compatible generation, and renewable generation projects.

The Regulation Act also continues statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter, as discussed in *Virginia Fuel Expenses*.

VIRGINIA FUEL EXPENSES

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices increased considerably during that period, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. 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 re-instituted beginning July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted, this mechanism ensures dollar for dollar recovery for prudently incurred fuel costs.

In April 2007, we filed a Virginia fuel factor application with the Virginia Commission. The application showed a need for an annual increase in fuel expense recovery for the period July 1, 2007 through June 30, 2008 of approximately $662 million; however, the requested increase was limited to $219 million under the 2007 amendments to the fuel cost recovery statute, which limited the increase to an amount that resulted in the residential customer class not receiving an increase of more than 4% of total rates in effect as of June 30, 2007. The Virginia Commission approved a fuel factor increase for Virginia jurisdictional customers of approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million deferred for subsequent recovery subject to Virginia Commission approval, without interest, during the period commencing July 1, 2008 and ending June 30, 2011.

In May 2008, we filed an application to revise our fuel factor with the Virginia Commission that would have resulted in an annual increase from 2.232 cents per kWh to 4.245 cents per kWh, effective July 1, 2008. This revised factor included $231 million of prior year under-recovered fuel expense out of a total estimated prior year under-recovered balance of $697 million with the remaining deferred fuel balance expected to be recovered over the next two fuel rate years beginning July 1, 2009. As part of the application, we proposed adoption of a rule that would limit the fuel factor to 3.893 cents per kWh for the current fuel period of July 1, 2008 through June 30, 2009. In order to achieve this lower fuel factor increase, the proposal would have delayed

recovery of the prior year under-recovered fuel balance of $697 million to be collected over a three-year period beginning July 1, 2009.

The Virginia Commission approved a Stipulation and Recommendation proposed by us and other parties, which provided for the following, effective July 1, 2008:

i) an increase of our fuel tariff to 3.893 cents per kWh for the collection of the current period and partial recovery of the prior year under-recovered fuel balance;
ii) the recovery of $231 million of the approximately $697 million prior year under-recovered fuel balance, with the balance to be recovered in subsequent fuel periods as provided by Virginia law;
iii) the fuel tariff of 3.893 cents per kWh is estimated to result in an under-recovery of $231 million of projected fuel expenses during the current period; and
iv) we will not propose to recover a return or interest or any other form of carrying costs on the balance of uncollected fuel expenses described in subsection (ii) above, including the estimated $231 million under-recovery of current period expenses described in subsection (iii), provided that the total amount on which we will not propose to recover interest or any other form of carrying costs is limited to $697 million.

The resulting increase in a 1,000 kWh Virginia jurisdictional residential customer s monthly bill is approximately 18% for the 2008 through 2009 fuel period.

North Carolina Regulation

In 2004, the North Carolina Commission commenced a review of our North Carolina base rates and subsequently ordered us to file a general rate case to show cause why our North Carolina jurisdictional base rates should not be reduced. The rate case was filed in September 2004, and in March 2005 the North Carolina Commission approved a settlement that included a prospective $12 million annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to annual fuel rate adjustments, with deferred fuel accounting for over- and under-recoveries of fuel costs.

NOTE 21. CREDIT RISK

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 December 31, 2008 provision for credit losses, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

We sell electricity and provide distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of our customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit

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Notes to Consolidated Financial Statements, Continued

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 December 31, 2008, our gross credit exposure totaled $74 million. After the application of collateral, our credit exposure is reduced to $58 million. Of this amount, investment grade counterparties, including those internally rated, represented 79%, and no single counterparty exceeded 24%.

NOTE 22. RELATED-PARTY TRANSACTIONS

We engage in related-party transactions primarily with affiliates. Our receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. We are included in Dominion s consolidated federal income tax return and participate in certain Dominion benefit plans. A discussion of significant related party transactions follows.

Transactions with Affiliates

We transact with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. We also enter into certain commodity derivative contracts with affiliates. We use these contracts, which are principally comprised of commodity swaps and options, to manage commodity price risks associated with purchases of natural gas. We designate the majority of these contracts as cash flow hedges for accounting purposes.

DRS provides accounting, legal, finance and certain administrative and technical services to us. In addition, we provide certain services to affiliates, including charges for facilities and equipment usage.

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31, (millions)	**2008**	2007	2006
Commodity purchases from affiliates	**$ 527**	$ 373	$ 234
Services provided by affiliates	**399**	345	311
Services provided to affiliates	**29**	25	26

In September 2008, we purchased a gas-fired turbine from an affiliate for $36 million as part of an expansion project at our Ladysmith (Unit 5) to supply electricity during periods of peak demand.

In December 2008, we merged with DNNA as part of our continued development efforts associated with the possible construction of a third nuclear unit at our North Anna facility. This merger has been approved by the Virginia and North Carolina Commissions and became effective December 1, 2008. As a result of the merger, we recorded assets and liabilities of $48 million, primarily reflecting the acquisition of an ESP and an in-process COL, and a payable to an affiliate that is expected to be settled in early 2009.

We have borrowed funds from Dominion under short-term borrowing arrangements. At December 31, 2008 and 2007, our outstanding borrowings, net of repayments, under the Dominion money pool for our nonregulated subsidiaries totaled $198 million and $114 million, respectively. Our short-term demand note

borrowings from Dominion were $219 million at December 31, 2008. There were no short-term demand note borrowings at December 31, 2007. We incurred interest charges related to our borrowings from Dominion of $10 million, $27 million and $10 million in 2008, 2007 and 2006, respectively.

In December 2008, as approved by the Virginia Commission, we issued 11,786 shares of our common stock to Dominion reflecting the conversion of $350 million of short-term demand note borrowings from Dominion to equity.

Lehman Brothers Inc. (LBI), a Lehman subsidiary, formerly acted as a remarketing agent for $153 million of our variable rate tax-exempt pollution control bonds. Due to several unsuccessful remarketing auctions of our variable rate tax-exempt pollution control bonds following the Lehman bankruptcy, Dominion repurchased $14 million of these bonds in September 2008, which were successfully remarketed by Barclays Capital, Inc. as successor remarketing agent in November 2008. Of the $153 million in variable rate bonds, $78 million matured or were redeemed in 2008. These variable rate tax-exempt financings are supported by a stand-alone $182 million five-year credit facility that terminates in February 2011.

NOTE 23. OPERATING SEGMENTS

We are organized primarily on the basis of the products and services we sell. The majority of our revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among our DVP and Generation segments. We manage our daily operations through the following segments:

DVP includes our electric transmission, distribution and customer service operations.

Generation includes our generation and energy supply operations.

Corporate and Other primarily includes specific items attributable to our operating segments. The contribution to net income by our primary operating segments is determined based on a measure of profit that 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, either in assessing the segments performance or in allocating resources among the segments, and are instead reported in the Corporate and Other segment.

In 2008, the Corporate and Other segment included $23 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2008 primarily related to impairment charges of $18 million ($11 million after tax) related to non-refundable deposits for certain generation-related vendor contracts and $8 million ($5 million after tax) reflecting other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts.

In 2007, the Corporate and Other segment included $166 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2007 largely resulted from a $259 million ($158 million after tax) extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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In 2006, the Corporate and Other segment included $12 million of net after-tax expenses attributable to our Generation segment. The net expenses in 2006 primarily related to a $13 million ($8 million after tax) impairment charge in the fourth quarter resulting from a change in our method of assessing other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts.

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	DVP	Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2008					
Operating revenue	**$ 1,439**	**$ 5,478**	**$ 17**	**$**	**$ 6,934**
Depreciation and amortization	**310**	**298**			**608**
Interest income	**15**	**9**		**(3)**	**21**
Interest and related charges	**144**	**167**	**1**	**(3)**	**309**
Income taxes	**182**	**331**	**(13)**		**500**
Net income (loss)	**307**	**583**	**(26)**		**864**
Capital expenditures	**792**	**1,245**			**2,037**
Total assets	**8,339**	**11,858**		**(1,395)**	**18,802**
2007					
Operating revenue	$ 1,467	$ 4,709	$ 5	$	$ 6,181
Depreciation and amortization	299	254	15		568
Interest income	6	9	8	(7)	16
Interest and related charges	133	174	3	(6)	304
Income taxes	212	166	(7)		371
Extraordinary item, net of tax			(158)		(158)
Net income (loss)	342	276	(170)		448
Capital expenditures	559	736			1,295
Total assets	7,705	10,525		(1,167)	17,063
2006					
Operating revenue	$ 1,396	$ 4,202	$ 5	$	$ 5,603
Depreciation and amortization	293	225	18		536
Interest income	4	32	8	(6)	38
Interest and related charges	129	173		(6)	296
Income taxes	212	80	(8)		284
Net income (loss)	339	151	(12)		478
Capital expenditures	524	523			1,047

NOTE 24. QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly results of operations for the years ended December 31, 2008 and 2007 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year

(millions)					
2008					
Operating revenue	**$ 1,524**	**$ 1,546**	**$ 2,177**	**$ 1,687**	**$ 6,934**
Income from operations	**418**	**390**	**561**	**252**	**1,621**
Net income	**222**	**200**	**303**	**139**	**864**
Balance available for common stock	**218**	**196**	**299**	**134**	**847**
2007					
Operating revenue	$ 1,443	$ 1,424	$ 1,833	$ 1,481	$ 6,181
Income from operations	181	191	582	272	1,226
Extraordinary item, net of tax		(158)			(158)
Net income (loss)	89	(79)	322	116	448
Balance available for common stock	85	(83)	318	112	432

Our 2007 results include the impact of the following significant items:

- Second quarter results include a $158 million after-tax extraordinary charge due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.
- Third and fourth quarter results reflect the reapplication of deferral accounting for Virginia jurisdiction fuel costs beginning July 1, 2007.

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Item 9A(T). Controls and Procedures

Senior management, including our CEO and CFO, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, our CEO and CFO have concluded that our disclosure controls and procedures are effective. There were no changes in our internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Virginia Electric and Power Company (Virginia Power) understands and accepts responsibility for our financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). We continuously strive to identify opportunities to enhance the effectiveness and efficiency of internal control, just as we do throughout all aspects of our business.

We maintain a system of internal control designed to provide reasonable assurance, at a reasonable cost, that our assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as our Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss our auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require our 2008 Annual Report to contain a management s report regarding the effectiveness of internal control. As a basis for our report, we tested and evaluated the design and operating effectiveness of internal controls. Based on our assessment as of December 31, 2008, we make the following assertion:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Virginia Power.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

We evaluated our internal control over financial reporting as of December 31, 2008. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Virginia Power maintained effective internal control over financial reporting as of December 31, 2008.

This annual report does not include an attestation report of the company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the company s independent registered public accounting firm pursuant to temporary rules of the SEC that permit the company to provide only management s report in this annual report.

Since management s assessment is required without an attestation report by the company s independent registered public accounting firm regarding internal control over financial reporting, management s report will be considered to be furnished rather than filed and therefore not subject to liability under Section 18 of the Exchange Act.

February 24, 2009

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PART IV.

Item 15. Exhibits and Financial Statement Schedules

2. Exhibits:

Exhibit 23 Consent of Deloitte and Touche LLP (filed herewith)

Exhibit 31.1 Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)

Exhibit 31.2 Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)

Exhibit 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)

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, on October 13, 2009.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ THOMAS F. FARRELL, II
Thomas F. Farrell, II
Chairman of the Board of Directors

And Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of October 13, 2009.

Signatures	Title
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ MARK F. MCGETTRICK **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ STEVEN A. ROGERS **Steven A. Rogers**	Director
/s/ ASHWINI SAWHNEY **Ashwini Sawhney**	Vice President Accounting (Chief Accounting Officer)

EXHIBIT LIST

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