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, 2005

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES 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.)**
701 East Cary 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
7.375% Trust Preferred Securities (cumulative), $25 par value	New York Stock Exchange

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

None

Indicate by check mark whether 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 (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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

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

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, 2006, there were issued and outstanding 198,047 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

EXPLANATORY NOTE

We are filing this Amendment No. 1 on Form 10-K/A solely to correct a typographical error made by our printer/filing agent in the process of converting and formatting the Annual Report on Form 10-K to an electronic format suitable for filing with the Securities Exchange Commission (SEC). The typographical error appeared in the Report of Management s Responsibilities and Report of Independent Registered Public Accounting Firm contained in Item 8. Financial Statements and Supplementary Data of our original Annual Report on Form 10-K filed on March 2, 2006 (Original Report). Specifically, the dates of the reports were incorrectly stated as March 1, 2006 and have been corrected to March 2, 2006.

In order to comply with certain technical requirements of the SEC s rules in connection with the filing of this amendment on Form 10-K/A; we are including in this amendment the complete text of Item 8. Financial Statements and Supplementary Data and Item 15. Exhibits and Financial Statement Schedules to reflect the filing of updated certifications of our principal executive and principal financial officers and updated Consent of Independent Registered Public Accounting Firm.

This Amendment No. 1 to our Report on Form 10-K as originally filed on March 2, 2006 continues to speak as of the date of our Original Report, and we have not updated the disclosures contained in this Amendment No. 1 to reflect any events that occurred at a date subsequent to the filing of the Original Report.

Item 8. Financial Statements and Supplementary Data

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Report of Management s Responsibilities

Because we are not an accelerated filer as defined in Exchange Act Rule 12b-2, we are not required to comply with Securities and Exchange Commission rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 until December 31, 2007.

Our management is responsible for all information and representations contained in our Consolidated Financial Statements and other sections of our annual report on Form 10-K. Our Consolidated Financial Statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with accounting principles generally accepted in the United States of America. Other financial information in the Form 10-K is consistent with that in our Consolidated Financial Statements.

Management maintains 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. Management recognizes the inherent limitations of any system of internal control and, therefore, cannot provide absolute assurance that the objectives of the established internal controls will be met. 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. Management believes that during 2005 the system of internal control was adequate to accomplish the intended objectives.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, who have been engaged by Dominion s Audit Committee, which is comprised entirely of independent directors. Deloitte & Touche LLP s audit was conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

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.

Management recognizes its responsibility for fostering a strong ethical climate so that our affairs are conducted according to the highest standards of personal corporate conduct. This responsibility is characterized and reflected in our code of ethics, which addresses potential conflicts of interest, compliance with all domestic and foreign laws, the confidentiality of proprietary information and full disclosure of public information.

March 2, 2006

Report of Independent Registered Public Accounting Firm

To the Board of Directors of

Virginia Electric and Power Company

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of income, common shareholder s equity and comprehensive income, and of cash flows for each of the three years in the period ended December 31, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for: conditional asset retirement obligations in 2005 and asset retirement obligations, contracts involved in energy trading, derivative contracts not held for trading purposes, derivative contracts with a price adjustment feature, and the consolidation of variable interest entities in 2003.

/s/ Deloitte & Touche LLP

Richmond, Virginia

March 2, 2006

Consolidated Statements of Income

Year Ended December 31, (millions)	**2005**	2004	2003
Operating Revenue	**$ 5,712**	$ 5,371	$ 5,191
Operating Expenses			
Electric fuel and energy purchases	**2,553**	1,751	1,475
Purchased electric capacity	**477**	550	607
Other energy-related commodity purchases	**34**	38	123
Other operations and maintenance:			
External suppliers	**653**	975	968
Affiliated suppliers	**292**	264	292
Depreciation and amortization	**527**	496	458
Other taxes	**170**	168	172
Total operating expenses	**4,706**	4,242	4,095
Income from operations	**1,006**	1,129	1,096
Other income	**70**	49	79
Interest and related charges:			
Interest expense	**292**	218	270
Interest expense junior subordinated notes payable to affiliated trust	**30**	31	
Distributions mandatorily redeemable trust preferred securities			30
Total interest and related charges	**322**	249	300
Income from continuing operations before income tax expense	**754**	929	875
Income tax expense	**269**	339	319
Income from continuing operations before cumulative effect of changes in accounting principles	**485**	590	556
Income (loss) from discontinued operations (net of income tax benefit of $274 in 2005 and $99 in 2004 and expense of $17 in 2003)	**(471)**	(159)	26
Cumulative effect of changes in accounting principles (net of income taxes of $3 in 2005 and $14 in 2003)	**(4)**		(21)
Net Income	**10**	431	561
Preferred dividends	**16**	16	15
Balance available for common stock	**$ (6)**	$ 415	$ 546

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

Consolidated Balance Sheets

At December 31, (millions)	**2005**	2004
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 54**	$ 2
Accounts receivable:		
Customers (less allowance for doubtful accounts of $7 and $13)	**700**	1,289
Other (less allowance for doubtful accounts of $9 and $5)	**60**	62
Receivables from affiliates	**7**	65
Inventories (average cost method):		
Materials and supplies	**207**	184
Fossil fuel	**236**	174
Gas stored		196
Derivative assets	**8**	1,097
Deferred income taxes	**32**	114
Other	**62**	124
Total current assets	**1,366**	3,307
Investments		
Nuclear decommissioning trust funds	**1,166**	1,119
Other	**22**	22
Total investments	**1,188**	1,141
Property, Plant and Equipment		
Property, plant and equipment	**20,317**	19,716
Accumulated depreciation and amortization	**(8,055)**	(7,706)
Total property, plant and equipment, net	**12,262**	12,010
Deferred Charges and Other Assets		
Regulatory assets	**326**	361
Prepaid pension cost	**35**	91
Derivative assets	**3**	174
Other	**269**	234
Total deferred charges and other assets	**633**	860
Total assets	**$ 15,449**	$ 17,318

At December 31, (millions)	**2005**	2004
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 618**	$ 12
Short-term debt	**905**	267
Accounts payable	**415**	799
Payables to affiliates	**42**	122
Affiliated current borrowings	**12**	645
Accrued interest, payroll and taxes	**288**	176
Derivative liabilities	**2**	1,304
Other	**210**	235
Total current liabilities	**2,492**	3,560
Long-Term Debt		
Long-term debt	**3,256**	4,326
Junior subordinated notes payable to affiliated trust	**412**	412
Notes payable other affiliates	**220**	220
Total long-term debt	**3,888**	4,958
Deferred Credits and Other Liabilities		
Deferred income taxes	**2,201**	2,200
Deferred investment tax credits	**49**	64
Asset retirement obligations	**834**	781
Derivative liabilities	**6**	163
Regulatory liabilities	**409**	387
Other	**80**	79
Total deferred credits and other liabilities	**3,579**	3,674
Total liabilities	**9,959**	12,192
Commitments and Contingencies (see Note 21)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder s Equity		
Common stock no par, 300,000 shares authorized, 198,047 shares outstanding	**3,388**	3,388
Other paid-in capital	**886**	50
Retained earnings	**842**	1,302
Accumulated other comprehensive income	**117**	129
Total common shareholder s equity	**5,233**	4,869
Total liabilities and shareholder s equity	**$ 15,449**	$ 17,318

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

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Consolidated Statements of Common Shareholder s Equity and Comprehensive Income

	Common Stock		Other		Accumulated Other	
	Shares	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income (Loss)	Total
(shares in thousands, all other amounts in millions)						
Balance at December 31, 2002	178	$ 2,888	$ 16	$ 1,419	$ 8	$ 4,331
Comprehensive income:						
Net income				561		561
Net deferred derivative gains hedging activities, net of $9 tax expense					11	11
Unrealized gains on nuclear decommissioning trust funds, net of $44 tax expense					68	68
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $5 tax expense					(7)	(7)
Net derivative losses hedging activities, net of $1 tax benefit					2	2
Total comprehensive income				561	74	635
Equity contribution by parent			21			21
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(575)		(575)
Balance at December 31, 2003	178	2,888	38	1,405	82	4,413
Comprehensive income:						
Net income				431		431
Net deferred derivative gains hedging activities, net of $10 tax expense					16	16
Unrealized gains on nuclear decommissioning trust funds, net of $20 tax expense					32	32
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $1 tax expense					(2)	(2)
Net derivative losses hedging activities, net of $0.5 tax benefit					1	1
Total comprehensive income				431	47	478
Issuance of stock to parent	20	500				500
Equity contribution by parent			11			11
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(534)		(534)
Balance at December 31, 2004	198	3,388	50	1,302	129	4,869
Comprehensive income:						
Net income				**10**		**10**
Net deferred derivative losses hedging activities, net of $5 tax benefit					**(8)**	**(8)**
Unrealized gains on nuclear decommissioning trust funds, net of $8 tax expense					**13**	**13**
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $4 tax expense					**(7)**	**(7)**
Net derivative gains hedging activities, net of $7 tax expense					**(10)**	**(10)**
Total comprehensive income				**10**	**(12)**	**(2)**
Equity contribution by parent			**833**			**833**
Tax benefit from stock awards and stock options exercised			**3**			**3**
Dividends				**(470)**		**(470)**
Balance at December 31, 2005	**198**	**$ 3,388**	**$ 886**	**$ 842**	**$117**	**$ 5,233**

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

Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2005	2004	2003
Operating Activities			
Net income	**$ 10**	$ 431	$ 561
Adjustments to reconcile net income to net cash from operating activities:			
Net realized and unrealized derivative (gains)/losses	**1,041**	(25)	88
Depreciation and amortization	**604**	578	531
Deferred income taxes and investment tax credits, net	**(267)**	125	245
Deferred fuel expenses, net	**76**	86	(202)
Gain on sale of emissions allowances	**(54)**	(35)	(5)
Other adjustments to net income	**9**	(16)	33
Changes in:			
Accounts receivable	**(149)**	(135)	(144)
Affiliated accounts receivable and payable	**(40)**		42
Inventories	**(18)**	(64)	(50)
Prepaid pension cost	**56**	40	(85)
Accounts payable	**253**	(51)	18
Accrued interest, payroll and taxes	**164**	(15)	17
Margin deposit assets and liabilities	**(69)**	4	(10)
Other operating assets and liabilities	**(120)**	206	136
Net cash provided by operating activities	**1,496**	1,129	1,175
Investing Activities			
Plant construction and other property additions	**(741)**	(761)	(986)
Nuclear fuel	**(111)**	(96)	(97)
Proceeds from sales of securities	**257**	237	256
Purchases of securities	**(311)**	(277)	(342)
Proceeds from sale of emissions allowances	**56**	41	5
Other	**50**	21	63
Net cash used in investing activities	**(800)**	(835)	(1,101)
Financing Activities			
Issuance (repayment) of short-term debt, net	**638**	(450)	274
Issuance (repayment) of affiliated current borrowings, net	**(256)**	491	54
Issuance of notes payable to parent			220
Issuance of long-term debt and preferred stock			1,055
Repayment of long-term debt	**(532)**	(344)	(1,165)
Issuance of common stock		500	
Common dividend payments	**(454)**	(518)	(560)
Preferred dividend payments	**(16)**	(16)	(15)
Other	**(24)**	(1)	(23)
Net cash used in financing activities	**(644)**	(338)	(160)
Increase (decrease) in cash and cash equivalents	**52**	(44)	(86)
Cash and cash equivalents at beginning of year	**2**	46	132
Cash and cash equivalents at end of year	**$ 54**	$ 2	$ 46
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 307**	$ 260	$ 260
Income taxes	**156**	46	64
Non-cash financing activities:			
Assumption of debt related to acquisitions of nonutility generating facilities	**62**	213	
Issuance of debt in exchange for electric distribution assets	**8**		
Exchange of debt securities		106	
Conversion of short-term borrowings and other amounts payable to parent to other paid-in capital	**200**	11	21
Transfer of investment in subsidiary to parent	**633**		

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

Notes to Consolidated Financial Statements

Note 1. Nature of Operations

Virginia Electric and Power Company (the Company), a Virginia public service company, is a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion). We are a regulated public utility that generates, transmits and distributes electricity within an area of approximately 30,000 square miles in Virginia and northeastern North Carolina. We serve approximately 2.3 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. The Virginia service area comprises about 65% of Virginia s total land area but accounts for over 80% of its population. On May 1, 2005, we became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO). As a result, we integrated our control area into the PJM energy markets.

As discussed in Note 8, on December 31, 2005, we completed a transfer of our indirect wholly-owned subsidiary, Virginia Power Energy Marketing, Inc. (VPEM), to Dominion through a series of dividend distributions, in exchange for a capital contribution. VPEM provides fuel and risk management services to us and other Dominion affiliates and engages in energy trading activities. Through VPEM, we had trading relationships beyond the geographic limits of our retail service territory and bought and sold natural gas, electricity and other energy-related commodities. As a result of the transfer, VPEM s results of operations will no longer be included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation. In addition, the discontinued operations of VPEM are now included in our Corporate segment results.

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 Electric and Power Company, one of Virginia Power and Electric Company s consolidated subsidiaries or operating segments or the entirety of Virginia Electric and Power Company, including our Virginia and North Carolina operations and our consolidated subsidiaries.

We manage our daily operations through three primary operating segments: Generation, Energy and Delivery. In addition, we report our corporate and other functions as a segment. Corporate also includes specific items attributable to our operating segments that are excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments.

Note 2. Significant Accounting Policies

General

We make certain estimates and assumptions in preparing our Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles). These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the periods presented. Actual results may differ from those estimates.

Our Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of the Company and our majority-owned subsidiaries, and those variable interest entities (VIEs) where we have been determined to be the primary beneficiary.

Certain amounts in our 2004 and 2003 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2005 presentation.

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 accounts receivable at December 31, 2005 and 2004 included $263 million and $251 million, respectively, of accrued unbilled revenue based on estimated amounts of electric energy delivered but not yet billed to our utility customers. We estimate unbilled utility 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 include:

- *Regulated electric sales* consist primarily of state-regulated retail electric sales, federally-regulated wholesale electric sales and electric transmission services subject to cost-of-service rate regulation; and

- *Other revenue* consists primarily of excess generation sold at market-based rates, miscellaneous service revenue from electric distribution operations and other miscellaneous revenue.

Electric Fuel and Purchased Energy Deferred Costs

Where permitted by regulatory authorities, the differences between actual electric fuel and purchased energy expenses and the 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 the recovery of fuel rate revenue in excess of current period expenses is recognized as a regulatory liability.

Effective January 1, 2004, the fuel factor provisions for our Virginia retail customers are locked in until the earlier of July 1, 2007 or the termination of capped rates, with a one-time adjustment of the fuel factor, effective July 1, 2007 through December 31, 2010, with no deferred fuel accounting. As a result, approximately 12% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is subject to deferral accounting. Prior to the amendments to the Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) and the Virginia fuel factor statute in 2004, approximately 93% of the cost of fuel used in electric generation and energy purchases used to serve utility customers had been subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as regulatory assets and are subject to recovery through future rates.

Income Taxes

We file a consolidated federal income tax return and participate in an intercompany tax allocation agreement with Dominion and its subsidiaries. Our current income taxes are based on our

Notes to Consolidated Financial Statements, Continued

taxable income, determined on a separate company basis. However, prior to the repeal of the Public Utility Holding Company Act of 1935 (the 1935 Act), effective in 2006, cash payments to Dominion were limited. Statement of Financial Accounting Standards (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. 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. 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. Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits. At December 31, 2005, our Consolidated Balance Sheet includes $113 million of current taxes payable to Dominion (recorded in accrued interest, payroll and taxes) and $11 million of noncurrent taxes payable to Dominion (recorded in other deferred credits and liabilities). At December 31, 2004, our Consolidated Balance Sheet included $24 million of current taxes payable to Dominion (recorded in accrued interest, payroll and taxes).

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 2005 and 2004, accounts payable includes $39 million and $41 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 a remaining maturity of three months or less.

Derivative Instruments

We use derivative instruments such as futures, swaps, forwards, options and financial transmission rights (FTRs) to manage the commodity, currency exchange and financial market risks of our business operations. We also managed a portfolio of commodity contracts held for trading purposes as part of VPEM s strategy to market energy and manage related risks.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires all derivatives, except those for which an exception applies, to be reported on 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 revenue resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

We hold certain derivative instruments that are not held for trading purposes and 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 exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Statement of Income Presentation:

- *Financially-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* All unrealized changes in fair value and settlements are presented in other operations and maintenance expense on a net basis.
- *Physically-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* Effective October 1, 2003, all unrealized changes in fair value and settlements for physical derivative sales contracts are presented in revenue, while all unrealized changes in fair value and settlements for physical derivative purchase contracts are reported in expenses. For periods prior to October 1, 2003, unrealized changes in fair value for physically settled derivative contracts were presented in other operations and maintenance expense on a net basis.

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

Derivative Instruments Designated as Hedging Instruments

We designate certain derivative instruments as cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the relationship between the hedging instrument and the hedged item is formally documented, as well as the risk management objective and 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 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 may elect to 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 have ceased to be highly effective hedges.

Cash Flow Hedges Prior to the transfer of VPEM, a portion of our hedge strategies represented cash flow hedges of the variable price risk associated with the purchase and sale of natural gas. We continue to use foreign currency forward 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 accumulated other comprehensive income (loss) (AOCI), to the extent they are effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, if it should occur, or earlier, if it becomes probable that the forecasted transaction will not occur.

Notes to Consolidated Financial Statements, Continued

Fair Value Hedges Prior to the transfer of VPEM, we also used fair value hedges to mitigate the fixed price exposure inherent in certain natural gas inventory. We continue to use designated interest rate swaps as fair value hedges to manage our interest rate exposure on certain fixed-rate long-term debt. 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.

Statement of Income Presentation Gains and losses on derivatives designated as hedges, when recognized, are included in operating revenue, operating expenses or interest and related charges in our Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. The portion of gains or losses on hedging instruments determined to be ineffective and the portion of gains or losses on hedging instruments excluded from the measurement of the hedging relationship s 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, are included in other operations and maintenance expense.

As discussed in Note 8, on December 31, 2005 we completed the transfer of VPEM to Dominion. VPEM manages a portfolio of commodity contracts held for trading and nontrading purposes. As a result of the transfer of VPEM to Dominion, these derivatives are no longer included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation.

Valuation Methods

Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

For options and contracts with option-like characteristics where 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 estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. If pricing information is not available from external sources, judgment is required to develop the estimates of fair value. For individual contracts, the use of different valuation models or assumptions could have a material effect on the contract s estimated fair value.

Nuclear Decommissioning Trust Funds

We account for and classify all investments in marketable debt and equity securities held by our nuclear decommissioning trust funds as available-for-sale securities. Accordingly, they are reported at fair value with realized gains and losses and any other-than-temporary declines in fair value included in earnings and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale 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 length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its average cost and the expected fair value of the security. If the market value of the security has been less than cost more than eight months and the decline in value is greater than 50% of its average cost, the security is written down to fair value at the end of the reporting period. If only one of the above criteria is met, a further analysis is performed to evaluate the expected recovery value based on third-party price targets. If the third-party price targets are below the security s average cost and one of the other criteria has been met, the decline is considered other-than-temporary, and the security is written down to fair value at the end of the reporting period.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as incurred. In 2005, 2004 and 2003, we capitalized interest costs of $6 million, $7 million and $18 million, respectively.

For electric distribution and transmission property subject to cost-of-service rate regulation, the depreciable cost of such property, less salvage value, is charged to accumulated depreciation at retirement. Cost of removal collections from utility customers and expenditures not representing asset retirement obligations (AROs) are recorded as regulatory liabilities or regulatory assets.

For generation-related and nonutility property, cost of removal not associated with AROs is charged to expense as incurred. We record gains and losses upon retirement of generation-related and nonutility property based upon the difference between proceeds received, if any, and the property s undepreciated basis 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:

	2005	2004	2003
(percent)			
Generation	**2.04**	1.97	1.83
Transmission	**1.97**	1.97	1.96
Distribution	**3.46**	3.46	3.43
General and other	**5.43**	5.76	5.47

Our nonutility property, plant and equipment is depreciated using the straight-line method over 25 years.

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis.

Notes to Consolidated Financial Statements, Continued

Emissions Allowances

Emissions allowances are issued by the Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (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, which are reported in other assets on 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 they are consumed, with the amortization reflected in depreciation and amortization on our Consolidated Statements of Income. We report purchases and sales of these allowances as investing activities on our Consolidated Statements of Cash Flows and gains or losses resulting from sales in other operations and maintenance expense on 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. These assets are written down to fair value if the sum of the expected future undiscounted cash flows is less than the carrying amounts.

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 and when revenue is collected from customers for expenditures that are not yet incurred. Regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the recovery 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 the 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. We report the accretion of the AROs due to the passage of time in other operations and maintenance expense.

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

2005

SFAS No. 153

On July 1, 2005, we adopted SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29*, which requires that all commercially substantive exchange transactions, for which the fair values of the assets exchanged are reliably determinable, be recorded at fair value, whether or not they are exchanges of similar productive assets. This amends the exception from fair value measurements in Accounting Principles Board (APB) Opinion No. 29, *Accounting for Nonmonetary Transactions*, for nonmonetary exchanges of similar productive assets and replaces it with an exception for only those exchanges that do not have commercial substance. There was no impact on our results of operations or financial condition related to our adoption of SFAS No. 153 and we do not expect the ongoing application of SFAS No. 153 to have a material impact on our results of operations or financial condition.

FIN 47

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on December 31, 2005. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is incurred generally upon acquisition, construction, or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. Our adoption of FIN 47 resulted in the recognition of an after-tax charge of $4 million, representing the cumulative effect of the change in accounting principle.

Presented below is our pro forma net income for 2005, 2004 and 2003 as if we had applied the provisions of FIN 47 as of January 1, 2003.

Year Ended December 31 (millions)	**2005**	2004	2003
Net income as reported	**$10**	$431	$561
Net income pro forma	**13**	431	561

If we had applied the provisions of FIN 47 as of January 1, 2003, our asset retirement obligations as of January 1, 2003, would have increased by $7 million and asset retirement obligations as of December 31, 2003 and December 31, 2004 would have increased by $8 million.

Notes to Consolidated Financial Statements, Continued

2004

FIN 46R

We adopted FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R) for our interests in VIEs that are not considered special purpose entities on March 31, 2004. FIN 46R addresses the identification and consolidation of VIEs, which are entities that are not controllable through voting interests or in which the VIEs equity investors do not bear the residual economic risks and rewards in proportion to voting rights. There was no impact on our results of operations or financial position related to this adoption. See Note 14.

2003

SFAS No. 143

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The effect of adopting SFAS No. 143 for 2003, as compared to an estimate of net income reflecting the continuation of former accounting policies, was to increase net income by $160 million. The increase was comprised of a $139 million after-tax benefit, representing the cumulative effect of a change in accounting principle and an increase in income before the cumulative effect of a change in accounting principle of $21 million.

EITF 02-3

On January 1, 2003, we adopted Emerging Issues Task Force (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,* that rescinded EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Adopting EITF 02-3 resulted in the discontinuance of fair value accounting for non-derivative contracts held for trading purposes. Those contracts are recognized as revenue or expense at the time of contract performance, settlement or termination. The EITF 98-10 rescission was effective for non-derivative energy trading contracts initiated after October 25, 2002. For all non-derivative energy trading contracts initiated prior to October 25, 2002, we recognized a charge of $90 million ($55 million after-tax) as the cumulative effect of this change in accounting principle on January 1, 2003.

EITF 03-11

On October 1, 2003, we adopted EITF Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3.* EITF 03-11 addresses classification of income statement related amounts for derivative contracts. Income statement amounts related to periods prior to October 1, 2003 are presented as originally reported. See Note 2.

Statement 133 Implementation Issue No. C20

In connection with a request to reconsider an interpretation of SFAS No. 133 the FASB issued Statement 133 Implementation Issue No. C20, Interpretation of the Meaning of *Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature.* Issue C20 establishes criteria for determining whether a contract s pricing terms that contain broad market indices (e.g., the consumer price index) could qualify as a normal purchase or sale and, therefore, not be subject to fair value accounting. We had several contracts that qualified as normal purchase and sales contracts under the Issue C20 guidance. However, the adoption of Issue C20 required those contracts to be initially recorded at fair value as of October 1, 2003, resulting in the recognition of an after-tax charge of $101 million, representing the cumulative effect of the change in accounting principle. As normal purchase and sales contracts, no further changes in fair value were recognized.

FIN 46R

On December 31, 2003, we adopted FIN 46R for our interests in special purpose entities, resulting in the consolidation of a special purpose lessor entity through which we had constructed, financed and leased a power generation project. As a result, our Consolidated Balance Sheet as of December 31, 2003 reflects an additional $364 million in net property, plant and equipment and deferred charges and $370 million of related debt. This resulted in additional depreciation expense of approximately $10 million in both 2005 and 2004. The cumulative effect in 2003 of adopting FIN 46R for our interests in the special purpose entity was an after-tax charge of $4 million, representing depreciation and amortization expense associated with the consolidated assets.

In 2002, we established Virginia Power Capital Trust II, which sold trust preferred securities to third party investors. We received the proceeds from the sale of the trust preferred securities in exchange for junior subordinated notes issued by us to be held by the trust. Upon adoption of FIN 46R, we began reporting as long-term debt our junior subordinated notes held by the trust rather than the trust preferred securities. As a result, in 2005 and 2004, we reported interest expense on the junior subordinated notes rather than preferred distribution expense on the trust preferred securities.

Note 4. Recently Issued Accounting Standards

SFAS No. 154

In May 2005, the FASB issued SFAS No. 154*, Accounting Changes and Error Corrections*. SFAS No. 154 applies to all voluntary changes in accounting principle, and requires retrospective application to prior periods financial statements of a voluntary change in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. We will apply the provisions of SFAS No. 154 to voluntary accounting changes on or after January 1, 2006.

Note 5. Operating Revenue

Our operating revenue consists of the following:

Year Ended December 31, (millions)	**2005**	2004	2003
Regulated electric sales	**$ 5,543**	$ 5,180	$ 4,876
Other	**169**	191	315
Total operating revenue	**$ 5,712**	$ 5,371	$ 5,191

Notes to Consolidated Financial Statements, Continued

Note 6. Income Taxes

Details of income tax expense for continuing operations were as follows:

Year Ended December 31, (millions)	**2005**	2004	2003
Current expense:			
Federal	**$ 157**	$ 184	$ 50
State	**40**	53	(3)
Total current	**197**	237	47
Deferred expense:			
Federal	**88**	121	241
State	**(1)**	(3)	47
Total deferred	**87**	118	288
Amortization of deferred investment tax credits, net	**(15)**	(16)	(16)
Total income tax expense	**$ 269**	$ 339	$ 319

For continuing operations, the statutory U.S. federal income rate reconciles to our effective income tax rates as follows:

Year Ended December 31,	**2005**	2004	2003
U.S statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
Utility plant differences	**0.1**	0.1	(0.6)
Amortization of investment tax credits	**(1.6)**	(1.3)	(1.4)
State income taxes, net of federal benefit	**3.4**	3.5	3.3
Employee benefits	**(0.6)**	(0.5)	(0.6)
Other, net	**(0.6)**	(0.3)	0.8
Effective tax rate	**35.7%**	36.5%	36.5%

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:

At December 31, (millions)	**2005**	2004
Deferred income tax assets:		
Deferred investment tax credits	**$ 19**	$ 25
Other	**129**	203
Total deferred income tax assets	**148**	228
Deferred income tax liabilities:		
Depreciation method and plant basis differences	**1,979**	1,956
Other comprehensive income	**75**	83
Deferred state income taxes	**113**	112
Other	**151**	165
Total deferred income tax liabilities	**2,318**	2,316
Total net deferred income tax liabilities(1)	**$ 2,170**	$ 2,088

(1) At December 31, 2005 and 2004, total net deferred income tax liabilities include $1 million and $2 million, respectively, of current deferred tax liabilities that were reported in other current liabilities.

At December 31, 2005, we had the following loss and credit carryforwards:

- Federal loss carryforwards of less than $1 million that expire if unutilized during the period 2023 through 2024;
- State loss carryforwards of $169 million that expire if unutilized during the period 2019 through 2023; and
- Federal and state minimum tax credits of $38 million that do not expire.

We are routinely audited by federal and state tax authorities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret them differently. We establish liabilities for tax-related contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*, and review them in light of changing facts and circumstances. Ultimate resolution of income tax matters may result in favorable or unfavorable adjustments that could be material. At December 31, 2005 our Consolidated Balance Sheet included $13 million of income tax-related contingent liabilities, at December 31, 2004, our Consolidated Balance Sheet included no significant income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Jobs Act)

The Jobs Act has several provisions for energy companies, including a deduction related to taxable income derived from qualified production activities. Our electric generation activities qualify as production activities under the Jobs Act. The Jobs Act limits the deduction to the lesser of taxable income derived from qualified production activities or the consolidated federal taxable income of Dominion and its subsidiaries. Our qualified production activities deduction for 2005 is limited to a minimal amount.

Note 7. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of natural gas, electricity and other energy-related products marketed and purchased, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133.

For the years ended December 31, 2005 and 2004, we recognized in net income $11 million of gains and $1 million of losses, respectively, as hedge ineffectiveness and $4 million and $3 million of gains, respectively, attributable to differences between spot prices and forward prices that are excluded from the measurement of effectiveness, in connection with fair value hedges of natural gas inventory.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2005:

(millions)	Accumulated Other Comprehensive Income After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ 1	$	118 months
Foreign currency	19	7	23 months
Total	$20	$ 7	

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 interest rates and foreign exchange rates.

Notes to Consolidated Financial Statements, Continued

Note 8. Discontinued Operations VPEM Transfer

On December 31, 2005, we completed the transfer of VPEM to Dominion through a series of dividend distributions. This resulted in a transfer of our negative investment in VPEM to Dominion in exchange for a capital contribution of $633 million. No gain or loss was recognized on the transfer.

VPEM provides fuel and risk management services to us by acting as an agent for one of our other indirect wholly-owned subsidiaries and will continue to provide these services following the transfer. VPEM also engages in energy trading activities and provides price risk management services to other Dominion affiliates through the use of derivative contracts. While we owned VPEM, certain of these derivative contracts were reported at fair value on our Consolidated Balance Sheets, with changes in fair value reflected in earnings. These price risk management activities performed on behalf of Dominion affiliates generated derivative gains and losses that affected our Consolidated Financial Statements.

As a result of the transfer, VPEM s results of operations will no longer be included in our Consolidated Financial Statements, and our Consolidated Statements of Income for periods prior to the transfer have been adjusted to reflect VPEM as a discontinued operation, on a net basis. VPEM s results for 2005, 2004 and 2003 include revenues of $807 million, $373 million and $250 million, respectively, losses before income taxes of $746 million and $259 million in 2005 and 2004, respectively, and income before income taxes in 2003 of $44 million. VPEM s results also include the following affiliated transactions:

Year Ended December 31, (millions)	**2005**	**2004**	**2003**
Purchases of natural gas, gas transportation and storage services from affiliates	**$ 1,241**	$ 1,150	$ 741
Sales of natural gas to affiliates	**1,371**	919	828
Net realized losses on affiliated commodity derivative contracts	**(32)**	(11)	(11)
Affiliated interest and related charges	**18**	6	2

At December 31, 2004, our Consolidated Balance Sheet included derivative assets of $84 million and derivative liabilities of $34 million related to transactions between VPEM and affiliates.

Note 9. Nuclear Decommissioning Trust Funds

We hold marketable debt and equity securities in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds, as of December 31, 2005 and 2004, are summarized below.

(millions)	**Fair Value**	**Total Unrealized Gains included in AOCI**	**Total Unrealized Losses included in AOCI (1)**
2005			
Equity securities	**$ 740**	**$168**	**$ 9**
Debt securities	**399**	**5**	**4**
Cash and other	**27**		
Total	**$1,166**	**$173**	**$13**
2004			
Equity securities	$ 678	$145	$ 3
Debt securities	392	9	1

Cash and other	49		
Total	$1,119	$154	$ 4

(1) In 2005, approximately $2 million of unrealized losses relate primarily to equity securities in a loss position for greater than one year. In 2004, approximately $1 million of unrealized losses relate primarily to equity securities in a loss position for greater than one year.

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2005 by contractual maturity are as follows:

	Amount
(millions)	
Due in one year or less	$ 36
Due after one year through five years	101
Due after five years through ten years	135
Due after ten years	127
Total	$399

Gross realized gains on the sale of available-for-sale securities totaled $19 million, $27 million and $25 million in 2005, 2004 and 2003, respectively, and gross realized losses totaled $8 million, $24 million and $13 million in 2005, 2004 and 2003, respectively. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

Note 10. Property, Plant and Equipment

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

At December 31,	**2005**	2004
(millions)		
Utility:		
Generation	**$10,243**	$10,135
Transmission	**1,671**	1,635
Distribution	**6,338**	6,025
Nuclear fuel	**870**	795
General and other	**551**	608
Plant under construction	**637**	511
	20,310	19,709
Nonutility other	**7**	7
Total property, plant and equipment	**$20,317**	$19,716

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Notes to Consolidated Financial Statements, Continued

Jointly-Owned Utility Plants

Our proportionate share of jointly-owned utility plants at December 31, 2005 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	$ 1,007	$ 2,075	$ 553
Accumulated depreciation	(395)	(930)	(122)
Nuclear fuel		393	
Accumulated amortization of nuclear fuel		(312)	
Plant under construction	34	59	1

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 11. Intangible Assets

All of our intangible assets are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $38 million, $27 million and $25 million for 2005, 2004 and 2003, respectively. There were no material acquisitions of intangible assets in 2005 or 2004. The components of our intangible assets are as follows:

At December 31,	**2005**		2004	
(millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Software and software licenses	**$ 250**	**$ 138**	$ 265	$ 129
Other	**62**	**14**	50	9
Total	**$ 312**	**$ 152**	$ 315	$ 138

Annual amortization expense for intangible assets is estimated to be $35 million for 2006, $30 million for 2007, $25 million for 2008, $21 million for 2009 and $15 million for 2010.

Note 12. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

December 31, (millions)	**2005**	2004
Regulatory assets:		
Income taxes recoverable through future rates[1]	**$ 46**	$ 51
Cost of decommissioning DOE uranium enrichment facilities[2]	**16**	18
Deferred cost of fuel used in electric generation[3]	**171**	248
RTO start-up costs and administration fees [4]	**39**	31
Termination of certain power purchase agreements[5]	**24**	
Other	**30**	13
Total regulatory assets	**$ 326**	$ 361
Regulatory liabilities:		
Provision for future cost of removal[6]	**$ 388**	$ 374
Other	**21**	13
Total regulatory liabilities	**$ 409**	$ 387

(1) Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.
(2) The cost of decommissioning the Department of Energy s (DOE) uranium enrichment facilities represents the unamortized portion of our required contributions to a fund for decommissioning and decontaminating the DOE s uranium enrichment facilities. The contributions began in 1992 and will continue over a 15-year period with escalation for inflation. These costs are currently being recovered in fuel rates through June 30, 2007.
(3) In connection with the settlement of the 2003 Virginia fuel rate proceeding, we agreed to recover previously incurred costs through June 30, 2007 without a return on a portion of the unrecovered balance. Remaining costs to be recovered totaled $139 million at December 31, 2005.
(4) The Federal Energy Regulatory Commission (FERC) has conditionally authorized our deferral of start-up costs incurred in connection with joining an RTO and on-going administration fees paid to PJM. We have deferred $35 million in start-up costs and administration fees and $4 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence at the end of the Virginia retail rate cap period, subject to regulatory approval.
(5) The North Carolina Utilities Commission (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.
(6) 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.

At December 31, 2005, approximately $163 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of RTO start-up costs and administration fees, the cost of terminating certain power purchase agreements and a portion of deferred fuel costs.

Note 13. Asset Retirement Obligations

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities. However, in 2005 we recognized additional AROs due to the adoption of FIN 47, which clarified when sufficient information is available to reasonably estimate the fair value of conditional AROs. These additional AROs totaled $8 million and relate to the future abatement of asbestos in our generation facilities. These obligations result from certain safety and environmental activities we are required to perform when asbestos is disturbed.

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

Notes to Consolidated Financial Statements, Continued

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 determined by our operational planning. The changes to our AROs during 2005 were as follows:

(millions)	Amount
Asset retirement obligations at December 31, 2004	$781
Accretion expense	44
Revisions in estimated cash flows	1
Obligations recognized upon adoption of FIN 47	8
Asset retirement obligations at December 31, 2005	$834

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2005 and 2004, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.2 billion and $1.1 billion, respectively.

Note 14. Variable Interest Entities

FIN 46R, addresses the consolidation of 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.

Certain variable pricing terms in some of our long-term power and capacity contracts cause those contracts to be considered potential variable interests in the counterparties. Six potential VIEs with which we have existing power purchase agreements (signed prior to December 31, 2003), have not provided sufficient information for us to perform our FIN 46R evaluation.

We have since determined that our interest in two of the potential VIEs is not significant. In addition, in May 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551 megawatt combined cycle facility located in Batesville, Mississippi, which was considered to be a potential VIE. We decided to divest our interest in the long-term power tolling contract in connection with our reconsideration of the scope of certain trading activities, including those we conducted on behalf of affiliates, and Dominion s ongoing strategy to focus on business activities within the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States.

As of December 31, 2005, no further information has been received from the three remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these three potential VIE supplier entities of $2.0 billion at December 31, 2005. We paid $196 million, $199 million and $199 million for electric generation capacity and $243 million, $149 million and $134 million for electric energy to these entities for the years ended December 31, 2005, 2004 and 2003, respectively.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts with two potential variable interest entities. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings. Total debt held by the entities is approximately $320 million. After completing our FIN 46R analysis, we concluded that although our interest in the contracts, as a result of their pricing terms, represent variable interests in these potential variable interest entities, we are not the primary beneficiary.

During 2005, we entered into four long-term contracts with unrelated limited liability corporations (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $205 million to the LLCs for coal and synthetic fuel produced from coal for the year-ended December 31, 2005. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts.

In accordance with FIN 46R, we consolidate the variable interest lessor entity through which we have financed and leased a power generation project. Our Consolidated Balance Sheets as of December 31, 2005 and 2004 reflect net property, plant and equipment of $348 million and $346 million, respectively, and $370 million of debt related to this entity. The debt is nonrecourse to us and is secured by the entity s property, plant and equipment.

Note 15. 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. In May 2005, we entered into a $2.5 billion five-year revolving credit facility with Dominion and Consolidated Natural Gas Company (CNG), a wholly-owned subsidiary of Dominion, that replaced our $1.5 billion three-year facility dated May 2004 and our $750 million three-year facility dated May 2002. This credit facility can also be used to support up to $1.25 billion of letters of credit.

At December 31, 2005, total outstanding commercial paper supported by the joint credit facility was $1.4 billion, of which our borrowings were $905 million, with a weighted average interest

Notes to Consolidated Financial Statements, Continued

rate of 4.46%. At December 31, 2004, total outstanding commercial paper supported by previous credit agreements was $573 million, of which our borrowings were $267 million, with a weighted average interest rate of 2.35%.

At December 31, 2005, total outstanding letters of credit supported by the joint credit facility was $892 million, of which less than $1 million were issued on our behalf. At December 31, 2004, total outstanding letters of credit supported by the joint credit facilities was $183 million, all of which were issued on behalf of other Dominion subsidiaries.

In January 2006, we issued $450 million of 5.4% senior notes that mature in 2016 and $550 million of 6.0% senior notes that mature in 2036. We used the proceeds from this issuance to repay short-term debt.

Note 16. Long-term Debt

December 31, (millions, except percentages)	**2005 Weighted Average Coupon[(1)]**	**2005**	2004
Long-Term Debt			
Secured First and Refunding Mortgage Bonds[(2)]:			
7.625%, due 2007		**$ 215**	$ 215
7.0% to 8.625%, due 2024 to 2025			512
Secured Bank Debt:			
Variable rate, due 2007[(3)]	**3.76%**	**370**	370
Unsecured Senior and Medium-Term Notes:			
4.50% to 5.75%, due 2006 to 2010	**5.42%**	**1,600**	1,600
4.75% to 8.625%, due 2013 to 2032	**5.51%**	**762**	706
Unsecured Callable and Puttable Enhanced Securities[SM], 4.10% due 2038[(4)]		**225**	225
Tax-Exempt Financings[(5)]:			
Variable rate, due 2008	**2.62%**	**60**	60
Variable rates, due 2015 to 2027	**2.61%**	**137**	137
4.95% to 9.62%, due 2005 to 2010	**5.54%**	**237**	242
2.3% to 7.55%, due 2014 to 2031	**5.02%**	**263**	263
Notes Payable to Affiliates			
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		**412**	412
Note Payable to Parent, 2.125%, due 2023		**220**	220
		4,501	4,962
Fair value hedge valuation[(6)]		**(8)**	1
Amount due within one year	**5.81%**	**(618)**	(12)
Unamortized discount and premium, net		**13**	7
Total long-term debt		**$ 3,888**	$ 4,958

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2005.
(2) Substantially all of our property is subject to the lien of the mortgage, securing our mortgage bonds. Due to the early redemption of $512 million of First Refunding Mortgage Bonds in 2005, we incurred $25 million of prepayment penalties and related charges that were recognized in interest expense on our Consolidated Statement of Income.
(3) Represents debt associated with a special purpose lessor entity that is consolidated in accordance with FIN 46R. The debt is nonrecourse to us and is secured by the entity s property, plant and equipment of $348 million and $346 million at December 31, 2005 and 2004, respectively.
(4) On December 15, 2008, $225 million of the 4.10% Callable and Puttable Enhanced Securities[SM] due 2038 are subject to redemption at par plus accrued interest, unless holders of related options exercise rights to purchase and remarket the notes.
(5) Certain pollution control equipment at our generating facilities has been pledged to support these financings. The variable rate tax-exempt financings are supported by a stand-alone $200 million three-year credit facility that terminates in May 2006. In February

2006 this facility was replaced with a five-year credit facility that terminates in February 2011.

(6) Represents changes in fair value of certain fixed rate long-term debt associated with fair value hedging relationships.

Notes to Consolidated Financial Statements, Continued

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, 2005 were as follows (in millions):

2006	2007	2008	2009	2010	Thereafter	Total
$618	$1,268	$290	$128	$250	$1,947	$4,501

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2005, 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 hold 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 to the trust. The junior subordinated notes constitute 100% of the trust s assets. The trust must redeem its trust preferred securities when the junior subordinated notes are repaid at maturity or if redeemed, prior to maturity.

Under previous accounting guidance, we consolidated the trust in our Consolidated Financial Statements. In accordance with FIN 46R, we ceased to consolidate the trust as of December 31, 2003 and instead report, as long-term debt on our Consolidated Balance Sheet, the junior subordinated notes issued by us and held by the trust.

Distribution payments on the trust preferred securities issued by the trust are considered to be fully and unconditionally guaranteed by us, when all of the related agreements are taken into consideration. Each guarantee agreement only provides for the guarantee of distribution payments on the trust preferred securities to the extent that the trust has funds legally and immediately available to make distributions. The trust s ability to pay amounts when they are due on the trust preferred securities is dependent solely upon our payment of amounts when they are due on the junior subordinated notes. If the payment on the junior subordinated notes is deferred, we may not make distributions related to our capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, we may not make any payments on, redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the junior subordinated notes.

Note 17. 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, 2005 and 2004. 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, 2005:

Dividend	Issued and Outstanding	Entitled Per Share Upon Liquidation

	Shares (thousands)	
$ 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	102.82(1)
6.98	600	102.80(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1) Through 7/31/2006; $102.47 commencing 8/1/2006; amounts decline in steps thereafter to $100.00 by 8/1/2013.
(2) Through 8/31/2006; $102.45 commencing 9/1/2006; amounts decline in steps thereafter to $100.00 by 9/1/2013.
(3) Dividend rate is 5.50% through 12/20/2007; after which, the rate will be determined according to periodic auctions for periods established by us at the time of the auction process. This series is not callable prior to 12/20/2007.

Note 18. Shareholder s Equity

Common Stock

In 2004, as approved by the Virginia State Corporation Commission (Virginia Commission), Dominion made an equity investment in the Company through the purchase of our common stock. We issued 20,115 shares of our common stock to Dominion for cash consideration of $500 million.

Other Paid-In Capital

In 2005, we recorded contributed capital of $633 million related to the transfer of our investment in VPEM to Dominion and $200 million in connection with the conversion of short-term borrowings. In 2004, we recorded $11 million of other paid-in capital in connection with the reduction in amounts payable to Dominion.

Accumulated Other Comprehensive Income

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

At December 31, (millions)	**2005**	2004
Net unrealized gains on derivatives hedging activities, net of tax	**$ 20**	$ 38
Net unrealized gains on nuclear decommissioning trust funds, net of tax	**97**	91
Total accumulated other comprehensive income	**$ 117**	$ 129

Note 19. Dividend Restrictions

The 1935 Act and related regulations issued by the Securities and Exchange Commission (SEC) impose restrictions on the

Notes to Consolidated Financial Statements, Continued

transfer and receipt of funds by a registered holding company, like Dominion, from its subsidiaries, including us. The restrictions include a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. In 2004, the SEC granted relief, authorizing our nonutility subsidiaries to pay dividends out of capital or unearned surplus in situations where such subsidiary has received excess cash from an asset sale, engaged in a restructuring, or is returning capital to an associate company. We are not bound by the foregoing restrictions on dividends imposed by the 1935 Act as of February 8, 2006, the effective date on which the 1935 Act was repealed under the Energy Policy Act of 2005.

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found not to be in the public interest. As of December 31, 2005, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion and CNG contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion or to receive dividends from our subsidiaries at December 31, 2005.

See Note 16 for a description of potential restrictions on our dividend payments in connection with the deferral of distribution payments on trust preferred securities.

Note 20. 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 generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. Our net periodic pension cost was $56 million, $40 million and $23 million in 2005, 2004 and 2003, respectively. Our contributions to the pension plan were $108 million in 2003. We did not contribute to the pension plan in 2005 or 2004.

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 $42 million, $44 million and $44 million in 2005, 2004 and 2003, respectively.

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 postretirement benefit costs through Voluntary Employees Beneficiary Associations. Our contributions to retiree health care and life insurance plans were $32 million, $34 million and $31 million in 2005, 2004 and 2003, respectively.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $11 million, $11 million and $10 million were incurred in 2005, 2004 and 2003, respectively.

Note 21. 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. We believe that the final disposition of these proceedings will not have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2005, 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)	2006	2007	2008	2009	2010	Thereafter	Total
Purchased electric capacity(1)	$441	$418	$387	$366	$352	$2,536	$4,500

(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 2023. 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, 2005, the present value of our total commitment for capacity payments is $2.8 billion. Capacity payments totaled $472 million, $570 million and $611 million, and energy payments totaled $378 million, $293 million and $289 million for 2005, 2004, and 2003, respectively.

In the first quarter of 2005, we paid $42 million in cash and assumed $62 million of debt in connection with the termination of a long-term power purchase agreement and the acquisition of the related generating facility used by Panda-Rosemary LP, a nonutility generator, to provide electricity to us. The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the date of acquisition. In connection with the termination of the agreement, we recorded an after-tax charge of $47 million.

In the second quarter of 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551-megawatt combined cycle facility located in Batesville, Mississippi. We recorded after-tax charges of $8 million and $112 million in 2005 and 2004, respectively, related to the divestiture of the contract.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings.

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. 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, 2005 are as follows:

2006	2007	2008	2009	2010	Thereafter	Total
(millions)						
$28	$24	$19	$14	$11	$38	$134

Notes to Consolidated Financial Statements, Continued

Rental expense totaled $32 million, $40 million and $49 million for 2005, 2004 and 2003, respectively, the majority of which is reflected in other operations and maintenance expense.

Environmental Matters

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

Historically, we recovered such costs arising from regulated electric operations through utility rates. However, to the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2010, in excess of the level currently included in Virginia jurisdictional rates, our results of operations will decrease. After that date, we may seek recovery through rates of only those environmental costs related to our transmission and distribution operations.

Superfund Sites

From time to time, we may be identified as a potentially responsible party (PRP) to a Superfund site. The Environmental Protection Agency (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.

In 1987, we and a number of other entities were identified by the EPA as PRPs at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Remediation design is complete for the Pennsylvania site, and total remediation costs are expected to be in the range of $13 million to $25 million. Based on allocation formulas and the volume of waste shipped to the site, we have accrued a reserve of $2 million to meet our obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, we have determined that it is probable that the PRPs will fully pay their share of the costs. We generally seek to recover our costs associated with environmental remediation from third party insurers. At December 31, 2005, any pending or possible insurance claims were not recognized as an asset or offset against obligations.

Nuclear Operations

Nuclear Decommissioning Minimum Financial Assurance

The Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2005 NRC minimum financial assurance amount, aggregated for our nuclear units, was $1.3 billion and has been satisfied by a combination of the funds being collected and deposited in the trusts and the real annual rate of return growth of the funds allowed by the NRC. In June 2005, we gave notice to the NRC that we were canceling our previous guarantee because, based on our calculations, the trusts now contain sufficient funds to meet NRC requirements without further assurances.

Nuclear Insurance

The Price-Anderson Act provides the public up to $10.8 billion of 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 United States, we could be assessed up to $100.6 million for each of our four licensed reactors, not to exceed $15 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, individually) 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 $55 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 $20 million.

Old Dominion Electric Cooperative, a part owner of North Anna Power Station, is responsible 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, with Dominion, filed a lawsuit in the United States

Notes to Consolidated Financial Statements, Continued

Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. We will continue to safely manage our spent fuel until it is accepted by the DOE.

Litigation

We are co-owners with ODEC of the Clover electric generating facility. In 1989, we entered into a coal transportation agreement with Norfolk Southern Railway Company (Norfolk Southern) for the delivery of coal to the facility. The agreement provides for a base rate price adjustment based upon a published index. Norfolk Southern claimed in October 2003 that an incorrect reference index was used to adjust the base transportation rate. In November 2003, we and ODEC filed suit against Norfolk Southern seeking to clarify the price escalation provisions of the transportation agreement. The trial court has ruled in Norfolk Southern s favor by concluding that the agreement specifies the higher rate adjustment factor which Norfolk Southern claims should have been applied in the past to adjust the base rate and which will be applied in the future. The court has not ruled on the calculation of any underpayments for past adjustments or for future rate adjustments. We believe that the court s interpretation of the transportation agreement and its ruling on other issues in the case are legally incorrect. We intend to prosecute this case and, if necessary, file an appeal when the case is concluded in the trial court. No liability has been recorded in our Consolidated Financial Statements related to this matter.

Guarantees and Surety Bonds

As of December 31, 2005, we had issued $51 million of guarantees primarily to support commodity transactions of subsidiaries. We had also purchased $15 million of surety bonds for various purposes, including providing worker compensation coverage and obtaining licenses, permits, and rights-of-way. 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, 2005, 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.

Stranded Costs

In 1999, Virginia enacted the Virginia Restructuring Act that established a detailed plan to restructure Virginia s electric utility industry. Under the Virginia Restructuring Act, the generation portion of our Virginia jurisdictional operations is no longer subject to cost-based regulation. The legislation s deregulation of generation was an event that required us to discontinue the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to the Virginia jurisdictional portion of our generation operations in 1999. In 2004, amendments to the Virginia Restructuring Act and the Virginia fuel factor statute were adopted. The amendments:

- Extend capped base rates by three and one-half years, to December 31, 2010, unless modified or terminated earlier under the Virginia Restructuring Act;
- Lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates under the Virginia Restructuring Act, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction;
- Provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier under the Virginia Restructuring Act), with no adjustment for previously incurred over-recovery or under-recovery of fuel costs; and
- End wires charges on the earlier of July 1, 2007 or the termination of capped rates.

Wires charges are permitted to be collected by utilities until July 1, 2007, under the Virginia Restructuring Act. Our wires charges are set at zero in 2006 for all rate classes, and as such, Virginia customers will not pay the fee in 2006 if they switch from us to a competitive service provider.

We believe capped electric retail rates and, where applicable, wires charges provided under the Virginia Restructuring Act provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Stranded costs are those generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market.

Recovery of our potential stranded costs remains subject to numerous risks even in the capped-rate environment. These include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items. At December 31, 2005, our exposure to potential stranded costs included: long-term power purchase agreements that could ultimately be determined to be above market; generating plants that could possibly become uneconomic in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements.

Notes to Consolidated Financial Statements, Continued

Note 22. 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. Fair values have been determined using available market information and valuation methodologies considered appropriate by management. The financial instruments carrying amounts and fair values are as follows:

At December 31,	2005		2004	
	Carrying Amount	**Estimated Fair Value[1]**	Carrying Amount	Estimated Fair Value[1]
(millions)				
Long-term debt[2]	**$3,874**	**$3,887**	$4,338	$4,455
Junior subordinated notes payable to affiliated trust	**412**	**423**	412	445
Note payable to parent	**220**	**230**	220	224

(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.

Note 23. 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, 2005 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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 credit risk was concentrated primarily within VPEM s energy commodity trading and risk management activities performed on behalf of other Dominion affiliates, as we transacted with a smaller, less diverse group of counterparties and transactions involved large notional volumes and volatile commodity prices. As a result of the transfer of VPEM, as of December 31, 2005, we did not have a significant exposure to credit risk.

Note 24. Related Party Transactions

We engage in related party transactions primarily with affiliates (Dominion subsidiaries). Our accounts receivable and payable balances with affiliates are settled based on contractual terms 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. The significant related party transactions are disclosed below.

Transactions with Affiliates

At December 31, 2005 we transferred VPEM to Dominion in exchange for a $633 million contribution of capital. In so doing, we are no longer involved in facilitating Dominion s enterprise risk management by entering into certain financial derivative commodity contracts with affiliates.

VPEM will continue to provide fuel management services to us by acting as agent for one of our other indirect wholly-owned subsidiaries.

In addition, we also transact with affiliates for certain quantities of natural gas and other commodities, in the ordinary course of business.

Dominion Resources Services, Inc. (Dominion Services) provides accounting, legal and certain administrative and technical services to us. We provide certain services to affiliates, including charges for facilities and equipment usage.

The transactions with VPEM, Dominion Services and other affiliates are detailed below:

Year Ended December 31, (millions)	**2005**	2004	2003
Commodity purchases from VPEM	**$ 357**	$ 220	$ 168
Commodity sales to VPEM	**14**	6	12
Commodity electric sales to other affiliates			10
Gas transportation and storage charges from other affiliates	**7**	7	7
Service fees paid to VPEM	**1**	1	1
Services provided by Dominion Services	**291**	263	291
Services provided to other affiliates	**26**	25	27
Interest income from VPEM	**3**	1	

Transactions with Dominion

We lease our principal office building from Dominion under an agreement that expires in 2008. The lease agreement is accounted for as a capital lease, with capitalized cost of the property under the lease, net of accumulated amortization, of approximately $5 million and $8 million at December 31, 2005 and 2004, respectively. The rental payments for this lease were $3 million each in 2005, 2004 and 2003.

We have borrowed funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2004, VPEM had borrowings from Dominion under short-term demand notes totaling $645 million. In February 2005, those outstanding demand note borrowings were converted to borrowings from the Dominion money pool. We borrowed additional funds from Dominion under the short-term demand notes during September 2005, of which $200 million were subsequently converted to contributed capital during the third quarter. At December 31, 2005, subsequent to the VPEM transfer, VPEM, independent of us, borrowed funds from the Dominion money pool to fund the repayment of the short-term borrowings we had on behalf of VPEM. Therefore, as of December 31, 2005, we had no remaining outstanding short-term note borrowings from Dominion; however, our remaining nonregulated subsidiaries had outstanding Dominion money pool borrowings totaling $12 million. At December 31, 2005 and 2004, our borrowings from Dominion under a long-term note totaled $220 million. We incurred interest charges related to our short-term and long-term borrowings from Dominion of $9 million, $6 million and $1 million in 2005, 2004 and 2003, respectively.

In 2004, as approved by the Virginia Commission, Dominion made an equity investment in the Company through the purchase

Notes to Consolidated Financial Statements, Continued

of our common stock. We issued 20,115 shares of our common stock to Dominion for cash consideration of $500 million. We used the proceeds in part to pay down our $345 million short-term demand note from Dominion. Also, in 2004, we recorded $11 million of other paid-in capital in connection with the reduction in amounts payable to Dominion.

Other Related Party Transactions

Upon adoption of FIN 46R for our interests in special purpose entities on December 31, 2003, we ceased to consolidate the Virginia Power Capital Trust II, a finance subsidiary of the Company. The junior subordinated notes issued by us and held by the trust are reported as long-term debt. We reported $30 million and $31 million of interest expense on the junior subordinated notes payable to affiliated trust in 2005 and 2004, respectively, and $30 million of distributions on mandatorily redeemable trust preferred securities in 2003.

Note 25. Operating Segments

As a result of the transfer of VPEM to Dominion on December 31, 2005, the nature and composition of our primary operating segments have changed to reflect the discontinued operations of VPEM in the Corporate segment. VPEM was formerly reflected in the Energy, Generation, and Corporate segments. All segment information for prior years has been recast to conform to the new segment structure.

We are organized primarily on the basis of products and services sold in the United States. 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 Delivery, Energy and Generation segments. We manage our operations through the following segments:

Delivery includes our regulated electric distribution and customer service business. The Delivery segment is subject to cost-of-service rate regulation and accordingly, applies SFAS No. 71.

Energy includes our tariff-based electric transmission operations, which are subject to cost-of-service rate regulation and accordingly, applies SFAS No. 71.

Generation includes our portfolio of electric generating facilities and our energy supply operations.

Corporate includes our corporate and other functions, as well as the discontinued operations of VPEM. The contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments   core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments. In 2005, we reported net expenses of $58 million in the Corporate segment attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following:

- A $77 million ($47 million after-tax) charge resulting from the termination of a long-term power purchase agreement attributable to Generation;
- A $13 million ($8 million after-tax) charge related to the sale of our interest in a long-term power tolling contract attributable to Generation; and
- A $6 million ($4 million after-tax) charge for the cumulative effect of an accounting change, as a result of the adoption of FIN 47.

In 2004, we reported net expenses of $155 million in the Corporate segment attributable to our operating segments. The net expenses in 2004 primarily related to the impact of the following:

- A $184 million ($112 million after-tax) charge related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Generation;
- A $71 million ($43 million after-tax) charge resulting from the termination of three long-term power purchase agreements, attributable to Generation; and
- A $12 million ($7 million after-tax) charge related to an agreement to settle a class action lawsuit involving a dispute over our rights to lease fiber-optic cable along a portion of our electric transmission corridor, attributable to Energy; partially offset by
- An $18 million ($11 million after-tax) benefit from the reduction of expenses accrued in 2003 associated with Hurricane Isable restoration activities, attributable to Delivery.

In 2003, we reported net expenses of $225 million in the Corporate segment attributable to our operating segments. The net expenses in 2003 primarily related to the impact of the following:

- $21 million net after-tax charge representing the cumulative effect of adopting new accounting principles, as described in Note 3 to our Consolidated Financial Statements, including:
  - SFAS No. 143: a $139 million after-tax benefit attributable to: Generation ($140 million after-tax benefit) and Delivery ($1 million after-tax charge);
  - Statement 133 Implementation Issue No. C20: a $101 million after-tax charge attributable to Generation;
  - EITF 02-3: a $55 million after-tax charge attributable to Energy; and
  - FIN 46R: a $4 million after-tax charge attributable to Generation;
- $197 million ($122 million after-tax) of incremental electric utility restoration expenses associated with Hurricane Isabel, attributable primarily to Delivery;
- $126 million ($77 million after-tax) of charges associated with the termination of two long-term power purchase agreements and restructuring of certain electric sales contracts, attributable to Generation; and
- An $8 million ($5 million after-tax) charge for severance costs for workforce reductions, attributable to Delivery ($3 million) and Generation ($2 million).

Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	Delivery	Energy	Generation	Corporate	Adjustments & Eliminations	Consolidated Total
2005						
Operating revenue	**$1,183**	**$ 213**	**$4,309**	**$ 8**	**$ (1)**	**$ 5,712**
Depreciation and amortization	**246**	**33**	**227**	**21**		**527**
Interest and related charges	**117**	**32**	**181**	**1**	**(9)**	**322**
Income tax expense (benefit)	**179**	**39**	**86**	**(35)**		**269**
Loss from discontinued operations, net of tax				**(471)**		**(471)**
Cumulative effect of change in accounting principle, net of tax				**(4)**		**(4)**
Net income (loss)	**298**	**66**	**175**	**(529)**		**10**
Capital expenditures	**390**	**131**	**331**			**852**
Total assets	**5,374**	**1,469**	**9,308**		**(702)**	**15,449**
2004						
Operating revenue	$1,142	$ 213	$4,007	$ 10	$ (1)	$ 5,371
Depreciation and amortization	234	34	206	22		496
Interest and related charges	99	24	128	1	(3)	249
Income tax expense (benefit)	173	46	220	(100)		339
Loss from discontinued operations, net of tax				(159)		(159)
Net income (loss)	288	76	380	(313)		431
Capital expenditures	309	117	431			857
Total assets	5,102	1,316	9,343	2,341(1)	(784)	17,318
2003						
Operating revenue	$1,101	$ 333	$3,751	$ 10	$ (4)	$ 5,191
Depreciation and amortization	224	32	171	31		458
Interest and related charges	123	33	144	4	(4)	300
Income tax expense (benefit)	158	44	244	(127)		319
Income from discontinued operations, net of tax				26		26
Cumulative effect of changes in accounting principles, net of tax				(21)		(21)
Net income (loss)	282	73	406	(200)		561

(1) Represents VPEM assets reported in the Corporate segment.

Notes to Consolidated Financial Statements, Continued

Note 26. Quarterly Financial Data (Unaudited)

A summary of our quarterly results of operations for the years ended December 31, 2005 and 2004 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, 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. As described in Note 8, we reported the operations of VPEM as discontinued operations beginning in the fourth quarter of 2005. Prior quarters for 2005 and 2004 have been restated to conform to this presentation. All differences between amounts previously reported in our Quarterly Reports on Forms 10-Q during 2005 and 2004 are a result of reporting the results of operations of VPEM as discontinued operations.

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2005					
Operating revenue	**$1,358**	**$1,285**	**$1,774**	**$1,295**	**$5,712**
Income from operations	**240**	**262**	**328**	**176**	**1,006**
Income from continuing operations before cumulative effect of change in accounting principles	**115**	**124**	**177**	**69**	**485**
Income (loss) from discontinued operations, net of tax	**(93)**	**(67)**	**(360)**	**49**	**(471)**
Net income (loss)	**22**	**57**	**(183)**	**114**	**10**
Balance available for common stock	**18**	**53**	**(187)**	**110**	**(6)**
2004					
Operating revenue	$1,332	$1,317	$1,502	$1,220	$5,371
Income (loss) from operations	382	267	504	(24)	1,129
Income (loss) from continuing operations	201	131	275	(17)	590
Income (loss) from discontinued operations, net of tax	(91)	(60)	(17)	9	(159)
Net income (loss)	109	72	259	(9)	431
Balance available for common stock	105	68	255	(13)	415

Our 2005 results include the impact of the following significant item:

- First quarter results include a $47 million net after-tax charge in connection with the termination of a long-term power purchase agreement.

Our 2004 results include the impact of the following significant items:

- Third quarter results include a $21 million after-tax benefit, related to the termination of a long-term power purchase agreement.
- Fourth quarter results include a $112 million after-tax charge related to the sale of our interest in a long-term power tolling contract that was divested in 2005.
- Fourth quarter results include $64 million of after-tax charges related to the termination of two long-term power purchase agreements.

Item 15. Exhibits and Financial Statement Schedules

23.1	Consent of Deloitte & Touche LLP (filed herewith).
31.1	Certification by Registrant s Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant s Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the Securities and Exchange Commission by Registrant s Chief Executive Officer and Chief Financial Officer, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

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.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ STEVEN A. ROGERS

(Steven A. Rogers, Vice President

(Principal Accounting Officer))

Date: March 6, 2006