VIRGINIA ELECTRIC & POWER CO
Form 10-K
March 02, 2006
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(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 EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

Virginia	**54-0418825**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

701 East Cary Street

Richmond, Virginia	**23219**
(Address of principal executive offices)	**(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

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Virginia Electric and Power Company

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Part 1

Item 1. Business

The Company

Virginia Electric and Power Company is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. In Virginia, we conduct business under the name Dominion Virginia Power. In North Carolina, we conduct business under the name Dominion North Carolina Power and serve retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, we sell electricity at wholesale to rural electric cooperatives and municipalities. The terms Company, we, our and us are used in this report and, depending on the context of their use, may refer to Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Electric and Power Company, including all of its consolidated subsidiaries.

All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion), a fully integrated gas and electric holding company.

As of December 31, 2005, we had approximately 7,000 full-time employees. Approximately 3,200 employees are subject to collective bargaining agreements.

We were incorporated in 1909 as a Virginia public service corporation. Our principal executive offices are located at 701 East Cary Street, Richmond, Virginia 23219 and our telephone number is (804) 819-2000.

Operating Segments

We manage our operations through three primary operating segments: Delivery, Energy and Generation. We also report corporate and other functions as a segment. While we manage our daily operations as described below, our assets remain wholly owned by us and our legal subsidiaries. For additional financial information on business segments and geographic areas, including revenues from external customers, see Notes 1 and 25 to our Consolidated Financial Statements. For additional information on operating revenue related to our principal products and services, see Note 5 to our Consolidated Financial Statements.

Delivery

Delivery includes our electric distribution system and customer service business. Electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina.

Competition

Within Delivery s service territory in Virginia and North Carolina, there is no competition for electric distribution service.

Regulation

Delivery s electric retail service, including the rates it may charge to customers, is subject to regulation by the Virginia State Corporation Commission (Virginia Commission) and the North Carolina Utilities Commission (North Carolina Commission). See *Regulation State Regulations* for additional information.

Properties

The Delivery segment electric distribution network includes approximately 54,000 miles of distribution lines, exclusive of service level lines in Virginia and North Carolina. The right-of-way grants for most of our electric lines have been obtained from the apparent owner of real estate, but underlying titles have not been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

Sources of Fuel Supply

Delivery s supply of electricity to serve our retail customers is primarily provided by the Generation segment. See *Generation* for additional information.

Seasonality

Delivery s business varies seasonally based on demand for electricity by residential and commercial customers for cooling and heating use due to changes in temperature.

Energy

Energy includes our tariff-based electric transmission system serving Virginia and northeastern North Carolina. 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 PJM energy markets.

Competition

Since the integration of our electric transmission facilities into PJM, our electric transmission business is no longer subject to competition in relation to transmission service provided to customers within the PJM region.

Regulation

Energy s electric transmission operations are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Virginia Commission and the North Carolina Commission. See *Regulation State Regulations* and *Regulation Federal Regulations* for additional information.

Properties

The Energy segment has approximately 6,000 miles of electric transmission lines of 69 kilovolt (kV) or more located in the states of North Carolina, Virginia and West Virginia. Portions of the electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, surplus capacity in the line, if any exists. While we continue to own and maintain these electric transmission facilities, they are now a part of PJM, which coordinates the planning, operation, emergency assistance, and exchanges of capacity and energy for such facilities.

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Seasonality

Energy s business varies seasonally based on demand for electricity by residential and commercial customers for cooling or heating use due to changes in temperature.

Generation

Generation includes our portfolio of electric generation facilities and our energy supply operations. Our electric generation operations serve customers in Virginia and northeastern North Carolina. Our generation facilities are located in Virginia, West Virginia and North Carolina. Our energy supply operations are responsible for managing capacity needs for our utility system resources.

Competition

For our electric generation operations, retail choice has been available for our Virginia jurisdictional electric customers since January 1, 2003; however, to date, competition in Virginia has not developed to the extent originally anticipated. See *Regulation State Regulations*. Currently, North Carolina does not offer retail choice to electric customers.

Regulation

In Virginia and North Carolina, our electric utility generation facilities, along with power purchases, are used to serve our utility service area obligations. Due to amendments to the Virginia Restructuring Act and the fuel factor statute in 2004, revenues for serving Virginia jurisdictional retail load are based on capped base rates through 2010 and the related fuel costs for the generating fleet, including power purchases, are subject to fixed rate recovery provisions until July 1, 2007, when a one-time adjustment will be made effective through December 31, 2010. Such adjustment will be prospective and will not take into account any over-recovery or under-recovery of prior fuel costs. Subject to market conditions, any generation remaining after meeting utility system needs is sold into PJM. See *Regulation* for additional information.

Properties

For a listing of our generation facilities, see Item 2. Properties.

Sources of Fuel Supply

Generation uses a variety of fuels to power its electric generation, as described below.

Nuclear Fuel Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

Fossil Fuel Generation primarily utilizes coal, oil and natural gas in its fossil fuel plants. Generation s coal supply is obtained through long-term contracts and spot purchases. Additional utility requirements are purchased mainly under short-term spot agreements.

We have a portfolio of firm natural gas transportation contracts (capacity) that allow flexible natural gas deliveries to our gas turbine fleet, while minimizing costs.

Seasonality

Sales of electricity for the Generation segment vary seasonally based on demand for electricity by residential and commercial customers for cooling and heating use due to seasonal changes in temperature.

Nuclear Decommissioning

Generation has four licensed, operating nuclear reactors at its Surry and North Anna plants in Virginia that serve our customers. Decommissioning represents the decontamination and removal of radioactive contaminants from a nuclear power plant once operations have ceased, in accordance with standards established by the Nuclear Regulatory Commission (NRC). Amounts collected from ratepayers and placed into trusts have been invested to fund the expected future costs of decommissioning the Surry and North Anna units.

The total estimated cost to decommission our four nuclear units is $1.5 billion and is primarily based upon site-specific studies completed in 2002. We will perform new cost studies in 2006. The cost estimate assumes that the method of completing decommissioning activities is prompt dismantlement. During 2003, the NRC approved our application for a 20-year life extension for the Surry and North Anna units.

We expect to decommission the units during the period 2032 to 2045.

	Surry		North Anna		
	Unit 1	Unit 2	Unit 1	Unit 2	Total
(millions)					
NRC license expiration year	2032	2033	2038	2040	
Most recent cost estimate	$ 375	$ 368	$ 391	$ 363	$ 1,497
Funds in trusts at December 31, 2005	326	321	266	253	1,166
2005 contributions to trusts	1.5	1.7	1.1	1.0	5.3

Corporate

We also have a Corporate segment. Corporate includes our corporate and other functions and 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. Also included in the Corporate segment are the discontinued operations of Virginia Power Energy Marketing, Inc. (VPEM), previously a subsidiary, that was transferred to Dominion in December 2005. See *Recent Developments* and Notes 1, 8 and 25 to our Consolidated Financial Statements.

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Recent Developments

On December 31, 2005, we completed a transfer of our indirect wholly-owned subsidiary, 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. As a result of the transfer, VPEM s results of operations will no longer be included in our Consolidated Financial Statements and the composition of our primary operating segments has changed to reflect the discontinued operations of VPEM, formerly in the Energy and Generation segments, in our Corporate segment. See *Introduction* in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and Notes 1, 8 and 25 to our Consolidated Financial Statements.

Regulation

We are subject to regulation by the Securities and Exchange Commission (SEC), FERC, the Environmental Protection Agency (EPA), Department of Energy (DOE), the NRC, the Army Corps of Engineers, and other federal, state and local authorities.

State Regulations

We are subject to regulation by the Virginia Commission and the North Carolina Commission.

We hold certificates of public convenience and necessity authorizing us to maintain and operate our electric facilities now in operation and to sell electricity to customers. However, we may not construct or incur financial commitments for construction of any substantial generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies.

Status of Electric Deregulation in Virginia

The Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) was enacted in 1999 and established a plan to restructure the electric utility industry in Virginia. The Virginia Restructuring Act addressed, among other things: capped base rates, RTO participation, retail choice, the recovery of stranded costs, and the functional separation of a utility s electric generation from its electric transmission and distribution operations.

Retail choice has been available to all of our Virginia regulated electric customers since January 1, 2003. We have also separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation and other divisions operate independently and prevent cross-subsidies between our generation division and other divisions.

In 2004, the Virginia Restructuring Act and the Virginia fuel factor statute were amended. The amendments:

- Extend capped base rates 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.

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007.

When our fuel factor is adjusted in July 2007, we will remain subject to the risk that fuel factor-related cost recovery shortfalls may adversely affect our margins. Conversely, we could experience a positive economic impact to the extent that we can reduce our fuel factor-related costs for our electric utility generation operations.

Other amendments to the Virginia Restructuring Act were also enacted in 2004 with respect to a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia for serving default service needs. Under the minimum stay exemption program, large customers with a load of 500 kilowatts or greater would be exempt from the twelve-month minimum stay obligation under capped rates if they return to supply service from the incumbent utility at market-based pricing after they have switched to supply service with a competitive service provider. The wires charge exemption program would allow large industrial and commercial customers, as well as aggregated customers in all rate classes, to avoid paying wires charges when selecting electricity supply service from a competitive service provider by agreeing to market-based pricing upon return to the incumbent utility. For 2006, our wires charges are set at zero for all rate classes. In February 2005, we joined a consortium to explore the development of a coal-fired electric power station in southwest Virginia.

See *Status of Electric Deregulation in Virginia and Recovery of Stranded Costs* in *Future Issues and Other Matters* in MD&A for additional information on capped base rates and stranded costs.

Retail Access Pilot Programs

The three retail access pilot programs, approved by the Virginia Commission in 2003, continue to be available to customers. There are currently six competitive suppliers and seven aggregators registered with us and licensed to supply electricity to customers in Virginia. Currently, the relationship between capped rates and market prices makes customer switching difficult.

Rate Matters

Virginia In December 2003, the Virginia Commission approved the proposed settlement of our 2004 fuel factor increase of $386 million. The settlement included a recovery period for the under-recovery balance over three and a half years. Approximately $171 million and $85 million of the $386 million was recovered in 2004 and 2005, respectively. The remaining unrecovered balance is expected to be recovered by July 1, 2007.

As a result of amendments to the Virginia Restructuring Act in 2004, our capped base rates were extended to December 31, 2010. In addition, our fuel factor provisions were frozen until July 1, 2007, when they will be adjusted once for the period through December 31, 2010. See *Status of Electric Deregulation in Virginia* above for additional information regarding the Virginia Restructuring Act amendments.

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North Carolina In connection with the North Carolina Commission s approval of Dominion s acquisition of Consolidated Natural Gas Company (CNG), we agreed not to request an increase in North Carolina retail electric base rates before 2006, except for certain events that would have a significant financial impact on our operations. However, in 2004 the North Carolina Commission commenced an investigation into our North Carolina base rates and subsequently ordered us to file a general rate case to show cause why our North Carolina base rates should not be reduced. The rate case was filed in September 2004, and in March 2005 the North Carolina Commission approved a settlement that included a prospective $12 million annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005.

Fuel rates are still subject to change under the annual fuel cost adjustment proceedings.

Federal Regulations

Energy Policy Act of 2005 (EPACT)

In August 2005, the President of the United States signed EPACT. Key provisions of EPACT include the following:

- Repeal of the Public Utility Holding Company Act of 1935 (the 1935 Act);
- Establishment of a self-regulating electric reliability organization governed by an independent board with FERC oversight;
- Provision for greater regulatory oversight by other federal and state authorities;
- Extension of the Price Anderson Act for 20 years until 2025;
- Provision for standby financial support and production tax credits for new nuclear plants;
- Grant of enhanced merger approval authority to FERC; and
- Provision of authority to FERC for the siting of certain electric transmission facilities if states cannot or will not act in a timely manner.

Many of the changes Congress enacted must be implemented through public notice and proposed rule making by the federal agencies affected and this process is ongoing. We will continue to evaluate the effects that EPACT may have on our business.

Federal Energy Regulatory Commission

Under the Federal Power Act, FERC regulates wholesale sales of electricity and transmission of electricity in interstate commerce by public utilities. We sell electricity in the wholesale market under our market-based sales tariff authorized by FERC. In addition, we have FERC approval of a tariff to sell wholesale power at capped rates based on our embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside our service territory. Any such sales would be voluntary. Our sales of natural gas, liquid hydrocarbon by-products and oil in wholesale markets are not regulated by FERC.

As required by the Virginia Restructuring Act, we joined an RTO and, in May 2005, integrated our transmission assets into PJM.

We are also subject to FERC s Standards of Conduct that govern conduct between interstate transmission gas and electricity providers and their marketing function or their energy related affiliates. The rule defines the scope of the affiliates covered by the standards and is designed to prevent transmission providers from giving their marketing functions or affiliates undue preferences.

Environmental Regulations

Each of our operating segments faces substantial regulation and compliance costs with respect to environmental matters. For discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance, see *Environmental Matters* in *Future Issues and Other Matters* in MD&A. Additional information can also be found in Item 3. Legal Proceedings and Note 21 to our Consolidated Financial Statements.

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

In March 2005, the EPA Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule. These rules, when implemented, will require significant reductions in future sulfur dioxide (SO_2), nitrogen oxide (NO_X) and mercury emissions from electric generating facilities. The SO_2 and NO_X emission reduction requirements are in two phases with initial reduction levels targeted for 2009 (NO_X) and 2010 (SO_2), and a second phase of reductions targeted for 2015 (SO_2 and NO_X). The mercury emission reduction requirements are also in two phases, with initial reduction levels targeted for 2010 and a second phase of reductions targeted for 2018. The new rules allow for the use of cap-and-trade programs. States are currently developing implementation plans, which will determine the levels and timing of required emission reductions in each of the states within which we own and operate affected generating facilities. These regulatory actions will require additional reductions in emissions from our fossil fuel-fired generating facilities. In November 2005, we announced initial plans to spend approximately $500 million to install additional emission controls on our coal-fired stations in Virginia over the next 10 years to comply with these rules.

In March 2004, the State of North Carolina filed a petition with the EPA under Section 126 of the Clean Air Act seeking additional NO_X and SO_2 reductions from electrical generating units in thirteen states, claiming emissions from the electrical generating units in those states are contributing to air quality problems in North Carolina. We have electrical generating units in two of the thirteen states. The EPA has proposed to address the issues raised by North Carolina through the state s implementation of CAIR and is expected to issue a final rulemaking in this regard in March 2006. At this time, we do not anticipate additional expenditures beyond those that will be required to comply with the EPA CAIR regulations.

The United States Congress is considering various legislative proposals that would require generating facilities to comply with more stringent air emissions standards. Emission reduction requirements under consideration would be phased in under a variety of periods of up to 15 years. If these new proposals are adopted, additional significant expenditures may be required.

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In July 2004, the EPA published new regulations that govern existing utilities that employ a cooling water intake structure, and whose flow levels exceed a minimum threshold. The EPA s rule presents several compliance options. We are evaluating information from certain of our power stations and expect to spend approximately $9 million over the next three years conducting studies and technical evaluations. We cannot predict the outcome of the EPA regulatory process or state with any certainty what specific controls may be required.

We have applied for or obtained the necessary environmental permits for the operation of our regulated facilities. Many of these permits are subject to re-issuance and continuing review.

Nuclear Regulatory Commission

All aspects of the operation and maintenance of our nuclear power stations, which are part of the Generation segment, are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

From time to time, the NRC adopts new requirements for the operation and maintenance of nuclear facilities. In many cases, these new regulations require changes in the design, operation and maintenance of existing nuclear facilities. If the NRC adopts such requirements in the future, it could result in substantial increases in the cost of operating and maintaining our nuclear generating units.

The NRC also requires us to decontaminate nuclear facilities once operations cease. This process is referred to as decommissioning, and we are required by the NRC to be financially prepared. For information on our decommissioning trusts, see *Generation Nuclear Decommissioning* and Note 9 to our Consolidated Financial Statements.

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Item 1A. Risk Factors

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these factors below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

Our operations are weather sensitive. Our results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. In addition, severe weather, including hurricanes, winter storms and droughts, can be destructive, causing outages and property damage that require us to incur additional expenses.

We are subject to complex governmental regulation that could adversely affect our operations. Our operations are subject to extensive federal, state and local regulation and may require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. Management believes the necessary approvals have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. However, new laws or regulations, or the revision or reinterpretation of existing laws or regulations, may require us to incur additional expenses.

Costs of environmental compliance, liabilities and litigation could exceed our estimates, which could adversely affect our results of operations. Compliance with federal, state and local environmental laws and regulations may result in increased capital, operating and other costs, including remediation and containment expenses and monitoring obligations. In addition, we may be a responsible party for environmental clean-up at a site identified by a regulatory body. Management cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up and compliance costs, and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

We are exposed to cost-recovery shortfalls because of capped base rates and amendments to the fuel factor statute in effect in Virginia. Under the Virginia Restructuring Act, as amended in 2004, our base rates (excluding, generally, a fuel factor with limited adjustment provisions, and certain other allowable adjustments) remain capped through December 31, 2010 unless modified or terminated consistent with the Virginia Restructuring Act. Although the Virginia Restructuring Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls. These include exposure to stranded costs, future environmental compliance requirements, certain tax law changes, costs related to hurricanes or other weather events, inflation, the cost of obtaining replacement power during unplanned plant outages and increased capital costs.

In addition, under the 2004 amendments to the Virginia fuel factor statute, our current Virginia fuel factor provisions are locked-in until the earlier of July 1, 2007 or the termination of capped rates by order of the Virginia Commission, with no deferred fuel accounting. The amendments provide for a

one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier), with no adjustment for previously incurred over-recovery or under-recovery. As a result of the current locked-in fuel factor and the uncertainty of what the one-time adjustment will be, we are exposed to fuel price and other risks. These risks include exposure to increased costs of fuel, including purchased power costs, differences between our projected and actual power generation mix and generating unit performance (which affects the types and amounts of fuel we use) and differences between fuel price assumptions and actual fuel prices.

Under the Virginia Restructuring Act, the generation portion of our electric utility operations is open to competition and resulting uncertainty. Under the Virginia Restructuring Act, the generation portion of our electric utility operations in Virginia is open to competition and is no longer subject to cost-based regulation. To date, a competitive retail market has been slow to develop. Consequently, it is difficult to predict the pace at which a competitive environment will evolve and the extent to which we will face increased competition and be able to operate profitably within this competitive environment.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including the threat of terrorist attack and ability to dispose of spent nuclear fuel, the disposal of which is subject to complex federal and state regulatory constraints. These risks also include the cost of and our ability to maintain adequate reserves for decommissioning, costs of replacement power, costs of plant maintenance and exposure to potential liabilities arising out of the operation of these facilities. We maintain decommissioning trusts and external insurance coverage to manage the financial exposure to these risks. However, it is possible that costs arising from claims could exceed the amount of any insurance coverage.

The use of derivative instruments could result in financial losses and liquidity constraints. We use derivative instruments, including futures, forwards, financial transmission rights, options and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these contracts involves management s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Derivatives designated under hedge accounting to the extent not offset by the hedged transaction can result in ineffectiveness losses. These losses primarily result from differences in the location and specifications of the derivative hedging instrument and the hedged item and could adversely affect our results of operations.

Our operations in regards to these transactions are subject to multiple market risks including market liquidity, counterparty credit strength and price volatility. These market risks are beyond our control and could adversely affect our results of operations and future growth.

For additional information concerning derivatives and commodity-based contracts, see *Market Risk Sensitive Instruments and Risk Management* in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Notes 2 and 7 to our Consolidated Financial Statements.

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An inability to access financial markets could affect the execution of our business plan. We rely on access to short-term money markets, longer-term capital markets and banks as significant sources of liquidity for capital requirements not satisfied by the cash flows from our operations. Management believes that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain disruptions outside of our control may increase our cost of borrowing or restrict our ability to access one or more financial markets. Such disruptions could include an economic downturn, the bankruptcy of an unrelated energy company or changes to our credit ratings. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled.

Changing rating agency requirements could negatively affect our growth and business strategy. As of February 1, 2006, our senior unsecured debt is rated BBB, stable outlook, by Standard & Poor s Rating Group (Standard & Poor s); A3, under review for possible downgrade, by Moody s Investors Service (Moody s); and BBB+, stable outlook, by Fitch Ratings Ltd. (Fitch). In order to maintain our current credit ratings in light of existing or future requirements, we may find it necessary to take steps or change our business plans in ways that may adversely affect our growth and earnings. A reduction in our credit ratings by Standard & Poor s, Moody s or Fitch could increase our borrowing costs and adversely affect operating results.

Potential changes in accounting practices may adversely affect our financial results. We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

Failure to retain and attract key executive officers and other skilled professional and technical employees could have an adverse effect on our operations. Implementation of our growth strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees in some areas is high and the inability to retain and attract these employees could adversely affect our business and future financial condition.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

We own our principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of our property is subject to the lien of the mortgage securing our First and Refunding Mortgage Bonds.

We lease our headquarters facility from Dominion. In addition, our Delivery, Energy and Generation segments share certain leased buildings and equipment. See Item 1. Business for additional information about each segment s principal properties.

Our Generation segment provides electricity for use on a wholesale and a retail level. Our Generation segment can supply electricity demand either from our generation facilities in Virginia, North Carolina and West Virginia or through purchased power contracts when needed. The following table lists our generating units and capability.

Virginia Electric and Power Company s Power Generation

Plant	Location	Primary Fuel Type	Net Summer Capability (Mw)
North Anna	Mineral, VA	Nuclear	1,621(a)
Surry	Surry, VA	Nuclear	1,598
Mt. Storm	Mt. Storm, WV	Coal	1,569
Chesterfield	Chester, VA	Coal	1,234
Chesapeake	Chesapeake, VA	Coal	595
Clover	Clover, VA	Coal	433(b)
Yorktown	Yorktown, VA	Coal	323
Bremo	Bremo Bluff, VA	Coal	227
Mecklenburg	Clarksville, VA	Coal	138
North Branch	Bayard, WV	Coal	74
Altavista	Altavista, VA	Coal	63
Southampton	Southampton, VA	Coal	63
Yorktown	Yorktown, VA	Oil	818
Possum Point	Dumfries, VA	Oil	786
Gravel Neck (CT)	Surry, VA	Oil	174
Darbytown (CT)	Richmond, VA	Oil	144
Chesapeake (CT)	Chesapeake, VA	Oil	115
Possum Point (CT)	Dumfries, VA	Oil	66
Northern Neck (CT)	Lively, VA	Oil	44
Low Moor (CT)	Covington, VA	Oil	48
Kitty Hawk (CT)	Kitty Hawk, NC	Oil	32
Remington (CT)	Remington, VA	Gas	580
Possum Point (CC)	Dumfries, VA	Gas	531(c)
Chesterfield (CC)	Chester, VA	Gas	397
Possum Point	Dumfries, VA	Gas	309
Elizabeth River (CT)	Chesapeake, VA	Gas	312
Ladysmith (CT)	Ladysmith, VA	Gas	290
Bellmeade (CC)	Richmond, VA	Gas	232
Gordonsville Energy (CC)	Gordonsville, VA	Gas	218
Rosemary (CC)	Roanoke Rapids, NC	Gas	165
Gravel Neck (CT)	Surry, VA	Gas	146
Darbytown (CT)	Richmond, VA	Gas	144
Bath County	Warm Springs, VA	Hydro	1,607(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Wood	80
Other	Various	Various	15
			15,515
Purchased Capacity			2,244
		Total Capacity	**17,759**

Note: (CT) denotes combustion turbine, (CC) denotes combined cycle and (Mw) denotes megawatt

(a) Excludes 11.6 percent undivided interest owned by Old Dominion Electric Cooperative (ODEC).
(b) Excludes 50 percent undivided interest owned by ODEC.
(c) Includes generating units that we operate under leasing arrangements.
(d) Excludes 40 percent undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

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Item 3. Legal Proceedings

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

See *Regulation* in Item 1. Business, *Future Issues and Other Matters* in MD&A and Note 21 to our Consolidated Financial Statements for additional information on rate matters and various regulatory proceedings to which we are a party.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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Part II

Item 5. Market for the Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion Resources, Inc. (Dominion) owns all of our common stock.

We paid quarterly cash dividends on our common stock as follows:

				Quarter
	1st	2nd	3rd	4th
(millions)				
2005	**$ 131**	**$ 107**	**$ 216**	**$**
2004	126	101	194	97

Restrictions on our payment of dividends are discussed in Note 19 to our Consolidated Financial Statements.

Item 6. Selected Financial Data

	2005(1)	2004(2)	2003(3)	2002	2001(4)
(millions)					
Operating revenue	**$ 5,712**	$ 5,371	$ 5,191	$ 5,003	$ 4,888
Income from continuing operations before cumulative effect of changes in accounting principles	**485**	590	556	801	426
Income (loss) from discontinued operations, net of tax(5)	**(471)**	(159)	26	(28)	20
Cumulative effect of changes in accounting principles, net of tax	**(4)**		(21)		
Net income	**10**	431	561	773	446
Balance available for common stock	**(6)**	415	546	757	423
Total assets	**15,449**	17,318	16,884	15,588	14,597
Long-term debt(6)	**3,888**	4,958	4,744	3,794	3,704
Preferred securities of subsidiary trust(6)				400	135

(1) Includes a $47 million after-tax charge in connection with the termination of a long-term power purchase agreement and an $8 million after-tax charge related to the sale of our interest in a long-term power tolling contract. Also in 2005, we adopted a new accounting standard that resulted in the recognition of the cumulative effect of a change in accounting principle. See Note 3 to our Consolidated Financial Statements.
(2) Includes a $112 million after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005 and a $43 million after-tax charge resulting from the termination of long-term power purchase agreements.
(3) Includes $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel, a $77 million after-tax charge resulting from the termination of long-term power purchase agreements and restructuring of certain electric sales contracts and a $21 million net after-tax loss for the adoption of accounting standards that resulted in the recognition of the cumulative effect of changes in accounting principles. See Note 3 to our Consolidated Financial Statements.
(4) Includes a $136 million after-tax charge resulting from the termination of long-term power purchase agreements.
(5) Reflects the net impact of the discontinued operations of our indirect wholly-owned subsidiary, Virginia Power Energy Marketing, Inc., which was transferred to Dominion Resources, Inc. through a series of dividend distributions on December 31, 2005.
(6) Upon adoption of Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, on December 31, 2003 with respect to a special purpose entity, we began reporting as long-term debt our junior subordinated notes held by a capital trust, rather than the trust preferred securities issued by the trust. See Note 3 to our Consolidated Financial Statements.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Virginia Electric and Power Company. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms Virginia Power, 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 Electric and Power Company s consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries. We are a wholly-owned subsidiary of Dominion Resources, Inc. (Dominion).

Contents of MD&A

The MD&A consists of the following information:

- Forward-Looking Statements
- Introduction
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information Energy Trading Activities
- Sources and Uses of Cash
- Future Issues and Other Matters

Forward-Looking Statements

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and winter storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments, including deregulation and changes in environmental and other laws and regulations to which we are subject;
- Cost of environmental compliance;
- Risks associated with the operation of nuclear facilities;
- Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;
- Capital market conditions, including price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;
- Fluctuations in interest rates;
- Changes in rating agency requirements or credit ratings and the effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Changes to our ability to recover investments made under traditional regulation through rates;
- Transitional issues related to the transfer of control over our electric transmission facilities to a regional transmission organization; and
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors.

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

Introduction

Virginia Electric and Power Company, a Virginia public service company, is a wholly-owned subsidiary of 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, municipalities, power marketers and other utilities. The Virginia service area comprises about 65% of Virginia s total land area, but accounts for over 80% of its population.

On December 31, 2005, we completed the 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 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 required to be reported at fair value on our Consolidated Balance Sheets, with changes in fair value reflected in earnings. These price risk management activities for Dominion affiliates generated derivative gains and losses that in turn 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.

Our businesses are managed through three primary operating segments: Delivery, Energy and Generation. The contributions to net income by our primary operating segments are determined based on a measure of profit that we believe represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by management in assessing segment performance or allocating resources among the segments. Those specific items are reported in the Corporate segment.

Delivery includes our electric distribution and customer service business. Electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina.

Revenue provided by electric distribution operations is based primarily on rates established by state regulatory authorities and state law. The profitability of this business is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings relates largely to changes in volumes, which are primarily weather sensitive, and changes in the cost of routine maintenance and repairs (including labor and benefits).

Energy includes our regulated electric transmission system located in Virginia and northeastern North Carolina. On May 1, 2005 our electric transmission business 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.

Revenue provided by regulated electric transmission operations is based primarily on rates established by the Federal Energy Regulatory Commission (FERC). The profitability of this business is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures (including labor and benefits).

Generation includes our portfolio of electric generating facilities and our energy supply operations. Our generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. Our electric generation operations serve customers in Virginia and northeastern North Carolina. Our generation facilities are located in Virginia, West Virginia and North Carolina. Our energy supply operations are responsible for managing capacity needs for our utility system resources.

Generation s earnings result from the generation and sale of electricity. Due to 2004 deregulation legislation, revenues for serving Virginia jurisdictional retail load are based on capped rates through 2010 and fuel costs for the utility fleet, including power purchases, are subject to fixed rate recovery provisions until July 1, 2007, when a one-time prospective adjustment will be made effective through December 2010.

Changes in our utility operating costs, particularly with respect to fuel and purchased power, relative to costs used to establish the rates, will impact our earnings. Variability also results from changes in demand, which is primarily weather dependent, the cost of labor and benefits and the timing, duration and costs of outages.

Corporate includes our corporate and other functions, the net impact of VPEM and specific items attributable to our primary operating segments that are excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments.

Accounting Matters

Critical Accounting Policies and Estimates

We have identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to our financial condition or results of operations under different conditions or using different assumptions. We have discussed the development, selection and disclosure of each of these policies with our Board of Directors that also serves as our Audit Committee.

Accounting for derivative contracts at fair value

We use derivative contracts, such as futures, swaps, forwards, options and financial transmission rights (FTRs), to buy and sell energy-related commodities and to manage our commodity and financial markets risks. Derivative contracts, with certain exceptions, are subject to fair value accounting and are reported on our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies.

Fair value of derivatives 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 use of statistical methods. 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. 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.

For cash flow hedges of forecasted transactions, we must estimate the future cash flows of the forecasted transactions, as well as evaluate the probability of occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could require discontinuance of hedge accounting or could affect the timing of the reclassification of gains and/or losses on cash flow hedges from accumulated other comprehensive income (loss) (AOCI) into earnings.

Use of estimates in long-lived asset impairment testing

Impairment testing for an individual or group of long-lived assets or intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an asset s carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset s fair value is less than its carrying amount. Performing an impairment test on long-lived assets involves our judgment in areas such as identifying circumstances indicating an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of market-based value) associated with the asset, including the selection of an appropriate discount rate. Although our cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors such as the expected use of the asset, including future production and sales levels, and expected fluctuations of prices of commodities sold and consumed. In 2005 and 2004, we did not test any significant long-lived assets or asset groups for impairment as no circumstances arose that indicated an impairment may exist.

Asset retirement obligations

We recognize liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These asset retirement obligations (AROs) are recognized at fair value as incurred, and are capitalized as part of the cost of the related tangible long-lived assets. In the absence of quoted market prices, we estimate the fair value of our AROs using present value techniques, in which we make various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. AROs currently reported on our Consolidated Balance Sheets were measured during a period of historically low interest rates. The impact on measurements of new AROs, using different rates in the future, may be significant. In the future, if we revise any assumptions used to calculate the fair value of existing AROs, we will adjust the carrying amount of both the ARO liability and related long-lived asset. We record accretion expense, increasing the ARO liability, with the passage of time. In 2005, 2004 and 2003, we recognized $44 million, $42 million and $38 million, respectively, of accretion expense, and expect to incur $47 million in 2006.

A significant portion of our AROs relate to the future decommissioning of our nuclear facilities. At December 31, 2005, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $798 million, representing approximately 96% of our total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with our nuclear decommissioning obligations.

We obtain from third-party experts periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these cost estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities, for each of our nuclear facilities. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rate by 0.5%, the amount recognized as of December 31, 2005 for our AROs related to nuclear decommissioning would have been $156 million higher.

Accounting for regulated operations

The accounting for our regulated electric operations differs from the accounting for nonregulated operations in that we are required to reflect the effect of rate regulation in our Consolidated Financial Statements. Specifically, our regulated businesses record assets and liabilities that nonregulated companies would not report under accounting principles generally accepted in the United States of America. 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.

We evaluate whether or not recovery of our regulatory assets through future regulated rates is probable and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of regulatory assets is determined to be less than probable, the regulatory asset will be written off and an expense will be recorded in the period such assessment is made. We currently believe the recovery of our regulatory assets is probable. See Notes 2 and 12 to our Consolidated Financial Statements.

Income taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret them differently. We establish liabilities for tax-related contingencies in accordance with Statement of Financial Accounting Standards (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 impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. In addition, deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets.

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Newly Adopted Accounting Standards

During 2005, 2004 and 2003, we were required to adopt several new accounting standards, the requirements of which are discussed in Note 3 to our Consolidated Financial Statements. The adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, (FIN 46R) on December 31, 2003 with respect to special purpose entities, affected the comparability of our 2005 and 2004 Consolidated Statements of Income to 2003 as follows:

- We were required to consolidate a variable interest lessor entity through which we had financed and leased a new power generation project. In 2005 and 2004, our Consolidated Statements of Income reflect depreciation expense on the net property, plant and equipment and interest expense on the debt associated with this variable interest lessor entity, whereas in 2003, the lease payments to this entity were reflected as rent expense in other operations and maintenance expense.
- In addition, under FIN 46R, we report as long-term debt our junior subordinated notes held by a capital trust rather than the trust preferred securities issued by the trust. 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.

Results of Operations

Presented below is a summary of contributions by our operating segments to net income:

Year Ended December 31, (millions)	**2005**	2004	2003
Delivery	**$ 298**	$ 288	$ 282
Energy	**66**	76	73
Generation	**175**	380	406
Primary operating segments	**539**	744	761
Corporate	**(529)**	(313)	(200)
Consolidated	**$ 10**	$ 431	$ 561

Overview

2005 vs. 2004

The combined net income contribution of our primary operating segments decreased 28% to $539 million, as compared to 2004, primarily reflecting a lower contribution from the Generation segment. The lower contribution was largely due to higher fuel and purchased power expenses, primarily resulting from higher commodity prices.

The decrease in net income was also impacted by the following items recognized in 2005 and reported in the Corporate segment:

- $471 million of after-tax losses associated with VPEM;
- A $47 million after-tax charge resulting from the termination of a long-term power purchase agreement;
- An $8 million after-tax charge related to the sale of our interest in a long-term power tolling contract; and
- A $4 million after-tax charge for the cumulative effect of an accounting change, as a result of the adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47).

In addition, the decrease in net income was impacted by items recognized in 2004 and reported in the Corporate segment that are discussed in further detail below.

2004 vs. 2003

Net income decreased 2% to $744 million, as compared to 2003, largely reflecting a lower contribution from the Generation segment, primarily resulting from the elimination of fuel deferral accounting for the Virginia jurisdiction. The elimination of fuel deferral accounting for the Virginia jurisdiction resulted in the recognition of fuel expenses in excess of amounts recovered in fixed fuel rates.

The decrease in net income was also impacted by the following items recognized in 2004 and reported in the Corporate segment:

- $159 million of after-tax losses associated with VPEM;
- A $112 million after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005 in connection with our exit from certain energy trading activities;
- $43 million of net after-tax charges resulting from the termination of certain long-term power purchase agreements; and
- A $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; partially offset by
- An $11 million after-tax benefit from the reduction of expenses accrued in 2003 associated with Hurricane Isabel restoration activities.

In addition, the decrease in net income was impacted by the following items recognized in 2003 that were reported in the Corporate segment:

- $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel;
- A $77 million after-tax charge resulting from the termination of two long-term power purchase agreements and restructuring of certain electric sales contracts;
- A $21 million net after-tax loss for the cumulative effect of changes in accounting principles, resulting from the adoption of several new accounting standards; and
- $5 million of after-tax severance costs associated with workforce reductions; partially offset by
- A $26 million after-tax benefit associated with VPEM.

Analysis of Consolidated Operations

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

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	**945**	1,239	1,260
Depreciation and amortization	**527**	496	458
Other taxes	**170**	168	172
Other income	**70**	49	79
Interest and related charges	**322**	249	300
Income tax expense	**269**	339	319
Income (loss) from discontinued operations, net of tax	**(471)**	(159)	26
Cumulative effect of changes in accounting principles, net of tax	**(4)**		(21)

An analysis of our results of operations for 2005 compared to 2004 and 2004 compared to 2003 follows:

2005 vs. 2004

Operating Revenue increased 6% to $5.7 billion, primarily reflecting:

- A $363 million increase in regulated electric sales reflecting a $153 million increase in sales to wholesale customers, a $99 million increase due to the impact of a comparatively higher fuel rate for non-Virginia jurisdictional customers, a $77 million increase primarily due to the impact of comparably favorable weather on customer usage and a $59 million increase associated with new customer connections, partially offset by a $25 million decrease due to variations in seasonal rate premiums and discounts. The fuel rate increase was more than offset by an increase in *Electric fuel and energy purchases expense*; and
- A $22 million decrease in other revenue, primarily attributable to a decrease in off-system sales.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 46% to $2.6 billion, reflecting an increase related to generation operations primarily resulting from higher commodity prices including purchased power and congestion costs associated with PJM.

Purchased electric capacity expense decreased 13% to $477 million, resulting from the termination of several long-term power purchase agreements in connection with the purchase of the related generating facilities in 2004 and 2005.

Other operations and maintenance expense decreased 24% to $945 million, primarily reflecting:

- A $186 million benefit related to FTRs granted by PJM to us as a load-serving entity to offset the congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A $54 million gain resulting from the sale of emissions allowances. Future sales, if any, are dependent on market liquidity and other factors; and
- The net benefit of the following items recognized in 2004:
    - A $184 million charge related to the sale of our interest in a long-term power tolling contract;
    - A $71 million charge resulting from the termination of three long-term power purchase agreements; partially offset by
    - An $18 million benefit from the reduction of accrued expenses associated with Hurricane Isabel restoration activities.

These benefits were partially offset by the following charges in 2005:

- A $77 million charge resulting from the termination of a long-term power purchase agreement;
- A $36 million increase in salaries, wages, and benefits expense, resulting from higher incentive-based compensation, wages and pension benefits; and
- A $17 million increase in operating expenses related to nonutility generating facilities acquired subsequent to September 2004.

Depreciation and amortization expense increased 6% to $527 million, due to incremental expense resulting from property additions.

Other income increased 43% to $70 million primarily reflecting a $9 million increase in net realized gains (including investment income) associated with nuclear decommissioning trust fund investments, a $3 million increase in rental income and a $2 million increase in interest income.

Interest and related charges increased 29% to $322 million, primarily reflecting the impact of prepayment penalties resulting from the early redemption of debt, additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations increased as a result of unfavorable price changes on unsettled commodity derivative contracts primarily used to execute price risk management activities undertaken on behalf of our affiliates.

2004 vs. 2003

Operating Revenue increased 3% to $5.4 billion, primarily reflecting:

- A $304 million increase in regulated electric sales primarily due to a $231 million increase as a result of the impact of a comparatively higher fuel rate on increased sales volumes and a $49 million increase from customer growth associated with new customer connections. The rate increase resulted from the settlement of a Virginia fuel rate case in December 2003. This increase was more than offset by an increase in *Electric fuel and energy purchases expense*; partially offset by
- A $124 million decrease in other revenue, primarily due to a $123 million decline in trading revenue resulting from the transfer of certain wholesale electric contracts to a Dominion subsidiary in 2003 and an $82 million decrease in volumes of nonregulated coal sales, partially offset by a $58 million increase from off-system sales.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 19% to $1.8 billion, primarily reflecting:

- A $408 million increase related to utility generation operations, resulting from the combined effects of an increase in the fixed fuel rate and the elimination of fuel deferral accounting for the Virginia jurisdiction, which resulted in the recognition of fuel expenses in excess of amounts recovered in fixed fuel rates. The increase also reflected higher generation volumes in the current year; partially offset by
- A $130 million decrease primarily associated with the transfer of certain wholesale electric contracts to a Dominion subsidiary in 2003.

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Purchased electric capacity expense decreased 9% to $550 million, driven by the termination of certain long-term power purchase agreements as a result of the purchase of the related nonutility generating facilities.

Other energy-related commodity purchases expense decreased 69% to $38 million, primarily reflecting a decrease in the cost of coal purchased for resale.

Depreciation and amortization expense increased 8% to $496 million, due to incremental expense resulting from property additions, including the consolidation of a variable interest lessor entity as a result of adopting FIN 46R at December 31, 2003.

Other income decreased 38% to $49 million, primarily reflecting lower net realized gains (including investment income) associated with nuclear decommissioning trust fund investments ($12 million), decreased interest income ($8 million) and decreased net gains on the disposition of assets ($5 million).

Interest and related charges decreased 17% to $249 million, primarily due to refinancing of callable mortgage bonds with lower cost unsecured debt in December 2003.

Loss from discontinued operations increased as a result of unfavorable price changes on unsettled commodity derivative contracts primarily used to execute price risk management activities undertaken on behalf of our affiliates.

Outlook

We believe our operating businesses will provide stable growth in net income in 2006. The following are growth factors that will impact these expected results:

- Continued growth in utility customers; and
- Losses in 2005 related to VPEM that will not recur.

The growth factors in 2006 will be partially offset by:

- A potential decrease in regulated electric sales, as compared to 2005, assuming our utility service territory experiences a return to normal weather in 2006;
- Increased pension and other benefits expense; and
- Increased interest expense.

Based on these projections, we estimate that cash flow from operations will increase in 2006, as compared to 2005. Management believes this increase will provide sufficient cash flow to maintain or grow our current dividend to Dominion.

Segment Results of Operations

Delivery

Delivery includes our electric distribution system and customer service operations.

Year Ended December 31,	**2005**	2004	2003
Net income contribution (millions)	**$ 298**	$ 288	$ 282
Electricity delivered (million mwhrs)	**81**	78	75
Degree days (electric service area):			
Cooling	**1,707**	1,585	1,393
Heating	**3,784**	3,682	3,865
Electric delivery customer accounts	**2,309**	2,267	2,227

mwhrs = megawatt hours

Presented below, on an after-tax basis, are the key factors impacting the Delivery segment s operating results:

2005 vs. 2004

(millions)	**Increase (Decrease)**
Regulated electric sales	
Weather	**$ 14**
Customer growth	**11**
North Carolina rate case settlement[1]	**6**
Interest expense	**(11)**
Depreciation and amortization	**(8)**
Salaries, wages and benefits expense	**(6)**
Change in segment revenue allocation[2]	**(2)**
Other	**6**
Change in net income contribution	**$ 10**

(1) A benefit resulting from the establishment of certain regulatory assets in connection with the settlement of a North Carolina rate case in the first quarter of 2005.
(2) A change in the seasonal allocation of electric utility base rate revenue among the primary operating segments effective January 1, 2005.

2004 vs. 2003

(millions)	**Increase (Decrease)**
Interest expense	$ 14
Regulated electric sales	
Customer growth	9
Weather	4
Reliability expenses[1]	(11)
Other[2]	(10)
Change in net income contribution	$ 6

(1) Higher reliability expenses, primarily due to increased tree trimming.
(2) Other factors, including an increase in pension expense.

Energy

Energy includes our electric transmission operations.

Year Ended December 31, (millions)	**2005**	2004	2003
Net income	**$66**	$76	$73

Presented below, on an after-tax basis, are the key factors impacting the Energy segment s operating results:

2005 vs. 2004

(millions)	**Increase (Decrease)**
Change in segment revenue allocation	**$ (3)**
Interest expense	**(3)**
Write-off RTO start-up and integration costs[1]	**(3)**
Salaries, wages and benefits expense	**(2)**
Regulated electric sales:	
Weather	**3**
Customer growth	**2**
Other	**(4)**
Change in net income contribution	**$(10)**

(1) The write-off of certain previously deferred start-up and integration costs associated with joining an RTO that are allocable to Virginia non-jurisdictional and wholesale customers.

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2004 vs. 2003

(millions)	Increase (Decrease)
Energy trading activities[1]	$16
Electric transmission margins[2]	(10)
Other	(3)
Change in net income contribution	$3

(1) Increase due to the transfer of certain wholesale electric contracts to another Dominion subsidiary in 2003.
(2) Lower electric transmission revenue, primarily due to decreased wheeling revenue resulting from lower contractual volumes and unfavorable market conditions.

Generation

Generation includes our portfolio of electric generating facilities, power purchase agreements, and energy supply operations.

Year Ended December 31,	**2005**	2004	2003
Net income contribution (millions)	**$ 175**	$ 380	$ 406
Electricity supplied (million mwhrs)	**81**	78	75

The Generation segment provides electricity primarily from nuclear, coal, oil, purchased power and natural gas. Presented below is a summary of the system s energy output by energy source.

	2005	2004	2003
Nuclear[1]	**31%**	32%	29%
Coal[2]	**37**	38	38
Oil	**4**	6	6
Purchased power, net	**22**	19	23
Natural gas[3]	**5**	5	3
Other	**1**		1
Total[4]	**100%**	100%	100%

(1) Excludes Old Dominion Electric Cooperative s (ODEC) 11.6% ownership interest in the North Anna Power Station.
(2) Excludes ODEC s 50% ownership interest in the Clover Power Station.
(3) Includes natural gas used in combustion turbines that are fueled by gas.
(4) Excludes off-system sales.

Presented below, on an after-tax basis, are the key factors impacting the Generation segment s operating results:

2005 vs. 2004

(millions)	Increase (Decrease)
Fuel expenses in excess of rate recovery	$(280)
Interest expense	(24)

Salaries, wages and benefits expense	(17)
Depreciation expense	(12)
Energy supply margin(1)	40
Regulated electric sales:	
Weather	39
Customer growth	24
Capacity expenses	37
North Carolina rate case settlement	10
Change in segment revenue allocation	5
Other	(27)
Change in net income contribution	$(205)

(1) The increase in energy supply margin primarily reflects a benefit related to FTRs.

2004 vs. 2003

(millions)	**Increase (Decrease)**
Fuel expenses in excess of rate recovery	$(115)
Capacity expenses	36
Regulated electric sales	
Customer growth	20
Weather	10
Loss of revenue due to Hurricane Isabel(1)	7
Interest expense	9
Other	7
Change in net income contribution	$ (26)

(1) Increase reflects a loss of revenue in 2003 associated with outages related to Hurricane Isabel.

Corporate

Corporate includes our corporate and other functions and specific items. Presented below are the Corporate segment s after-tax results:

Year Ended December 31, (millions)	**2005**	2004	2003
VPEM discontinued operations	**$ (471)**	$ (159)	$ 26
Specific items attributable to operating segments	**(58)**	(155)	(225)
Other		1	(1)
Net loss	**$ (529)**	$ (313)	$ (200)

2005

We reported a net loss of $529 million in our Corporate segment, primarily reflecting $471 million of after-tax losses in 2005 incurred by VPEM.

We also reported the following specific items (reported in other operations and maintenance expense) attributable to our primary operating segments:

- A $77 million ($47 million after-tax) charge in connection with the termination of a long-term power purchase agreement (Generation); and
- A $13 million ($8 million after-tax) charge related to the sale of our interest in a long-term power tolling contract (Generation).

2004

We reported a net loss of $313 million in our Corporate segment including $159 million of losses incurred in 2004 related to VPEM operations, as well as the following items:

- A $184 million ($112 million after-tax) charge related to the sale of our interest in a long-term power tolling contract (Generation);
- A $71 million ($43 million after-tax) of charges from the termination of three long-term power purchase agreements (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 (Energy); partially offset by
- An $18 million ($11 million after-tax) benefit from the reduction of expenses accrued in 2003 associated with Hurricane Isabel restoration activities (Delivery).

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2003

In addition to $26 million of income from VPEM operations, we reported the following items in our Corporate segment:

- $122 million of after-tax incremental restoration expenses associated with Hurricane Isabel;
- A $77 million after-tax charge resulting from the termination of two long-term power purchase agreements and the restructuring of certain electric sales contracts;
- $5 million of after-tax severance costs associated with workforce reductions; and
- A $21 million net after-tax charge for the cumulative effect of changes in accounting principles, resulting from the adoption of the following new accounting standards:
  - $139 million after-tax benefit adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations;*
  - $101 million after-tax charge adoption of SFAS No. 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;*
  - $55 million after-tax charge adoption of Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities;* and
  - $4 million after-tax charge adoption of FIN 46R.

Selected Information Energy Trading Activities

We previously engaged in energy trading and marketing activities through VPEM. On December 31, 2005, VPEM was transferred to Dominion. As a result of the transfer, we no longer perform these energy trading and marketing activities.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during 2005 follows:

(millions)	**Amount**
Net unrealized loss at December 31, 2004	$ (35)
Redefinition of trading contracts	**125**
Contracts realized or otherwise settled during the period	**(71)**
Net unrealized gain at inception of contracts initiated during the period	
Change in unrealized gains and losses attributable to net arbitrage gains and changes in market prices	**(333)**
Transfer of VPEM energy trading contracts	**314**
Net unrealized loss at December 31, 2005	**$**

Sources and Uses of Cash

We depend on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided through operating activities are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through sales of securities and additional long-term financing.

At December 31, 2005, we had cash and cash equivalents of $54 million and $207 million of unused capacity under our joint credit facility.

Cash Flows from Discontinued Operations

The impact of VPEM s operations on our Consolidated Statements of Cash Flows is presented below. We do not expect the transfer of VPEM to Dominion to have a negative impact on our future liquidity.

Year Ended December 31,	**2005**	2004	2003

(millions)			
Operating cash flows	**$ 365**	$ (289)	$ (13)
Investing cash flows	**106**	(110)	
Financing cash flows	**(468)**	392	(16)

Operating Cash Flows

As presented on our Consolidated Statements of Cash Flows, net cash flows from operating activities were $1.5 billion in 2005, $1.1 billion in 2004 and $1.2 billion in 2003. We believe that our operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and maintain or grow current dividends payable to Dominion.

Our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, including:

- Cost-recovery shortfalls due to capped base rates and fixed fuel recovery provisions in effect in Virginia for our generation operations;
- Unusual weather and its effect on energy sales to customers and energy commodity prices;
- Extreme weather events that could disrupt or cause catastrophic damage to our electric distribution and transmission systems;
- Exposure to unanticipated changes in prices for energy commodities purchased or sold;
- Effectiveness of our risk management activities and underlying assessment of market conditions and related factors, including energy commodity prices, basis, liquidity, volatility, counterparty credit risk, availability of generation and transmission capacity, currency exchange rates and interest rates;
- The cost of replacement of electric energy in the event of longer-than-expected or unscheduled generation outages; and
- Contractual or regulatory restrictions on transfers of funds among us, Dominion and its subsidiaries.

Credit Risk

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 VPEM 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.

Investing Cash Flows

During 2005, 2004 and 2003, our investing activities resulted in net cash outflows of $800 million, $835 million and $1.1 billion, respectively. Significant investing activities for 2005 included $741 million for plant construction and other property additions and $111 million for nuclear fuel expenditures.

In addition, investing activities for 2005 included $311 million used for purchases of securities and $257 million in proceeds from sales of securities related to investments held in our nuclear decommissioning trusts. Investing activities also reflect $56 million of proceeds from the sale of emissions allowances.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by the cash provided by our operations. As discussed in *Credit Ratings* below, our ability to borrow funds or issue securities and the return demanded by investors are affected by our credit ratings. In

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addition, the raising of external capital is subject to certain regulatory approvals, including authorization by the Virginia State Corporation Commission (Virginia Commission).

In December 2005, the Securities and Exchange Commission (SEC) adopted rules that modify the registration, communications and offering processes under the Securities Act of 1933. The rules streamline the shelf registration process to provide registrants with more timely access to capital. Under the new rules, we meet the definition of a well-known seasoned issuer. This allows us to use an automatic shelf registration statement to register any offering of securities, other than those for business combination transactions.

During 2005, 2004 and 2003, net cash flows used in financing activities were $644 million, $338 million and $160 million, respectively.

Joint Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper to fund working capital requirements, as a bridge to long-term debt financing. 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.

Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2005, total commercial paper outstanding under the joint credit facility was $1.4 billion and the total amount of letter of credit issuances was $892 million, leaving approximately $207 million available for issuance. We are required to pay minimal annual commitment fees to maintain the credit facility.

In addition, the joint credit agreement contains various terms and conditions that could affect our ability to borrow funds under this facility. They include maximum debt to total capital ratios, material adverse change clauses and cross-default provisions.

The credit facility includes a defined maximum total debt to total capital ratio. The ratio of our debt to total capital, as defined by the agreement, should not exceed 65% at the end of any fiscal quarter. As of December 31, 2005, our calculated debt to total capital ratio was 46%. Under the agreement s cross-default provisions, if we or any of our material subsidiaries fail to make payment on various debt obligations in excess of $25 million, we may be required by the lenders to accelerate our repayment of any outstanding borrowings under the credit facility and the lenders could terminate their commitment to lend funds to us. However, any defaults on indebtedness by Dominion, CNG or any material subsidiaries of those affiliates would not affect the lenders commitment to us under the joint credit agreement.

Long-Term Debt

In February 2005, in connection with the acquisition of a nonutility generating facility from Panda Rosemary LP (Rosemary), we assumed $62 million of Rosemary s 8.625% senior notes that mature in 2016. In addition, in February and April of 2005, we issued $2 million and $6 million, respectively, of 7.25% promissory notes, which mature in 2025 and 2032, respectively, in exchange for electric distribution facilities at certain military bases in connection with their privatization.

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.

During 2005, we repaid $532 million of long-term debt securities.

Common Shareholder s Equity

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.

In 2004, 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 affiliated short-term demand note from Dominion.

Borrowings from Parent

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, these outstanding demand note borrowings were converted to borrowings under 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 we had no remaining outstanding short-term note borrowings from Dominion and our nonregulated subsidiaries had outstanding Dominion money pool borrowings totaling $12 million. At December 31, 2005 and 2004, our borrowings under a long-term note totaled $220 million. We incurred interest charges related to these short-term and long-term borrowings of $9 million and $6 million at December 31, 2005 and 2004, respectively.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. We believe that our current credit ratings provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to us may affect our ability to access these funding sources or cause an increase in the return required by investors.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing our credit ratings. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. Our credit ratings are most affected by our financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and event risk, if applicable.

Our credit ratings as of February 1, 2006 follow:

	Fitch	Moody s	Standard & Poor s
Mortgage bonds	A	A2	A-
Senior unsecured (including tax-exempt) debt securities	BBB+	A3	BBB
Preferred securities of affiliated trust	BBB	Baa1	BB+
Preferred stock	BBB	Baa2	BB+
Commercial paper	F2	P-1	A-2

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These credit ratings reflect Standard & Poor s December 2005 downgrade of its credit ratings for our senior unsecured debt securities. Standard & Poor s concluded that our fuel expenses in excess of rate recovery have caused a deterioration in financial performance to a level more commensurate with a BBB rating and that there will be no material improvement in our credit profile before mid-year 2007. In January 2006, Moody s announced that it had placed our credit ratings under review for possible downgrade, citing recent financial performance that was weaker than expected, a decline in funds from operations and higher than expected leverage. Moody s review is expected to be completed within three months. As of February 1, 2006, Fitch Ratings Ltd. (Fitch) and Standard & Poor s maintain a stable outlook for their ratings of the Company.

Generally, a downgrade in our credit rating would not restrict our ability to raise short-term or long-term financing as long as our credit rating remains investment grade, but it would increase the cost of borrowing. We work closely with Fitch, Moody s and Standard & Poor s, with the objective of maintaining our current credit ratings. In order to maintain our current ratings, we may find it necessary to modify our business plans and such changes may adversely affect our growth.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, we must enter into enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to our capital stock to Dominion, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and, in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to us. Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation, restrictions on disposition of substantial assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2005, there were no events of default under our covenants.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Presented below is a table summarizing cash payments that may result from contracts to which we are a party as of December 31, 2005. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market- based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities on our Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable and interest rate swaps. The majority of current liabilities will be paid in cash in 2006.

(millions)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Long-term debt[1]	$618	$1,558	$378	$1,947	$4,501
Interest payments[2]	255	321	228	1,590	2,394
Leases	28	43	25	38	134
Purchase obligations[3]:					
Purchased electric capacity for utility operations	441	805	718	2,536	4,500
Fuel to be used for utility operations	772	819	501	640	2,732

Other	35	9	4	3	51
Other long-term liabilities(4)	6	10			16
Total cash payments	$2,155	$3,565	$1,854	$6,754	$14,328

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders.
(2) Does not reflect our ability to defer distributions related to our junior subordinated notes payable to affiliated trusts.
(3) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.
(4) Primarily includes interest rate swap agreements. Excludes regulatory liabilities and AROs that are not contractually fixed as to timing and amount. See Notes 12 and 13 to the Consolidated Financial Statements. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year.

Planned Capital Expenditures

Our planned capital expenditures during 2006 and 2007 are expected to total approximately $946 million and $1.1 billion, respectively. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Included in our total planned capital expenditures are the following:

Capacity

Based on available generation capacity and current estimates of growth in customer demand, we will likely need additional baseload generation in the future. However, we currently have no definite plans to build any new baseload generating units in the near-term. We continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future. Through 2008, we will continue to meet any additional capacity and energy requirements through PJM market purchases.

Plant and Equipment

Our annual capital expenditures for plant and equipment for 2006, including environmental upgrades and construction improvements, are expected to total approximately as follows:

- Generation and nuclear fuel: $448 million;
- Transmission: $122 million; and
- Distribution: $376 million.

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Future Issues and Other Matters

Status of Electric Deregulation in Virginia

The Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) was enacted in 1999 and established a plan to restructure the electric utility industry in Virginia. The Virginia Restructuring Act addressed, among other things: capped base rates, RTO participation, retail choice, the recovery of stranded costs and the functional separation of a utility s electric generation from its electric transmission and distribution operations.

Retail choice has been available to all of our Virginia regulated electric customers since January 1, 2003. We have also separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation and other divisions operate independently and prevent cross-subsidies between the generation and other divisions.

In 2004, the Virginia Restructuring Act and the Virginia fuel factor statute were amended. The amendments:

- Extend capped base rates 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.

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007 and there is no adjustment for over- or under-recovery of fuel costs, including purchased power costs, through that date.

When our fuel factor is adjusted in July 2007, we will remain subject to the risk that fuel factor-related cost recovery shortfalls may adversely affect our margins. Conversely, we could experience a positive economic impact to the extent that we can reduce our fuel factor-related costs for our electric utility generation-related operations.

Other amendments to the Virginia Restructuring Act were also enacted in 2004 with respect to a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia for serving default service needs. Under the minimum stay exemption program, large customers with a load of 500 kilowatts or greater would be exempt from the twelve-month minimum stay obligation under capped rates if they return to supply service from the incumbent utility at market-based pricing after they have switched to supply service with a competitive service provider. The wires charge exemption program would allow large industrial and commercial customers, as well as aggregated customers in all rate classes, to avoid paying wires charges when selecting electricity supply service from a competitive service provider by agreeing to market-based pricing upon return to the incumbent utility. For 2006, our wires charges are set at zero for all rate classes. In February 2005, we joined a consortium to explore the development of a coal-fired electric power station in southwest Virginia.

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not reasonably be expected to be recovered in a competitive market. At December 31, 2005, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements. We believe capped electric retail rates will provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. 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.

The generation-related cash flows provided by the Virginia Restructuring Act are intended to compensate us for continuing to provide generation services and to allow us to incur costs to restructure such operations during the transition period. As a result, during the transition period, our earnings may increase to the extent that we can reduce operating costs for our utility generation-related operations. Conversely, the same risks affecting the recovery of our stranded costs may also adversely impact our margins during the transition period. Accordingly, we could realize the negative economic impact of any such adverse event. Using cash flows from operations during the transition period, we may further alter our cost structure or choose to make additional investments in our business.

Energy Policy Act of 2005 (EPACT)

In August 2005, the President of the United States signed EPACT. Key provisions of EPACT include the following:

- Repeal of the 1935 Act in February 2006;
- Establishment of a self-regulating electric reliability organization governed by an independent board with FERC oversight;
- Provision for greater regulatory oversight by other federal and state authorities;
- Extension of the Price Anderson Act for 20 years until 2025;
- Provision for standby financial support and production tax credits for new nuclear plants;
- Grant of enhanced merger approval authority to FERC; and
- Provision of authority to FERC for the siting of certain electric transmission facilities if states cannot or will not act in a timely manner.

Many of the changes Congress enacted must be implemented through public notice and proposed rule making by the federal agencies affected and this process is ongoing. We will continue to evaluate the effects that EPACT may have on our business.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. 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 the Virginia jurisdictional electric retail rates, our results of operations will decrease. After that date, recovery through regulated rates may be sought for only those environmental costs related to regulated electric transmission and distribution operations and recovery, if any, through the generation component of rates will be dependent upon the market price of electricity.

Environmental Protection and Monitoring Expenditures

We incurred approximately $134 million, $115 million and $100 million of expenses (including depreciation) during 2005, 2004 and 2003, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $137 million and $131 million in 2006 and 2007. In addition, capital expenditures related to environmental controls were $42 million, $84 million and $197 million for 2005, 2004 and 2003, respectively. These expenditures are expected to be approximately $166 million and $179 million for 2006 and 2007.

Clean Air Act Compliance

We are required by the Clean Air Act (the Act) to reduce air emissions of various air pollutants that are the by-products of fossil fuel combustion. The Act s new Clean Air Interstate Rule and Clean Air Mercury Rule will require significant reductions in future SO_2, NO_X and mercury emissions from our electric generating facilities and will require capital expenditures. The Act s existing SO_2 and NO_X reduction programs already include:

- The issuance of a limited number of SO_2 emissions allowances. Each allowance permits the emission of one ton of SO_2 into the atmosphere;
- NO_X emission limitations applicable during the ozone season months of May through September and on an annual average basis; and
- SO_2 and NO_X allowances may be transacted with a third party.

Implementation of projects to comply with these SO_2, NO_X and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of allowances and emission control technology. In response to these requirements, we estimate that we will make capital expenditures at our affected generating facilities of approximately $700 million during the period 2006 through 2010.

Future Environmental Regulations

The United States (U.S.) Congress is considering various legislative proposals that would require generating facilities to comply with more stringent air emissions standards. Emission reduction requirements under consideration would be phased in under a variety of periods of up to 15 years. If these new proposals are adopted, additional significant expenditures may be required.

In 1997, the U.S. signed an international Protocol to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. Currently, the Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation s greenhouse gas emission intensity by 18% over the period 2002-2012. Several legislative proposals that include provisions seeking to impose mandatory reductions of greenhouse gas emissions are under consideration in the U.S. Congress. The cost of compliance with the Protocol or other mandatory greenhouse gas reduction obligations could be significant. Given the highly uncertain outcome and timing of future action, if any, by the U.S. federal government on this issue, we cannot predict the financial impact of future climate change actions on our operations at this time.

Restructuring of Contracts with Nonutility Generator

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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K. The reader s attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may affect our future.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates, foreign currency exchange rates and equity security prices as described below. Commodity price risk is due to our exposure to market shifts for prices received and paid for natural gas, electricity and other commodities. Interest rate risk is generally related to our outstanding debt. We are exposed to foreign currency exchange rate risks related to our purchase of fuel services denominated in a foreign currency. In addition, we are exposed to equity price risk through various portfolios of equity securities.

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

Commodity Price Risk

To manage price risk associated with purchases and sales of natural gas, electricity and certain other commodities, we hold commodity-based financial derivatives. As part of VPEM s strategy to market energy and manage related risks, it holds commodity-based financial derivative instruments held for trading purposes. It also manages price risk associated with purchases and sales of natural gas, electricity and certain other commodities using commodity-based financial derivative instruments held for non-trading purposes.

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

A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $104 million in the fair value of our commodity-based financial derivatives held for trading purposes as of December 31, 2004. A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $12 million as of December 31, 2004. As discussed in Note 8 to our Consolidated Financial Statements, on December 31, 2005, we completed the transfer of VPEM to Dominion. As a result, at December 31, 2005, we did not have significant exposure to commodity price risk associated with financial derivative instruments.

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

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a portfolio of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2005, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $6 million. A hypothetical 10% increase in market interest rates, as determined at December 31, 2004, would have resulted in a decrease in annual earnings of approximately $3 million.

Foreign Currency Exchange Risk

We manage our foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk for these purchases is minimal. A hypothetical 10% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $6 million and $10 million in the fair value of currency forward contracts held by us at December 31, 2005 and 2004, respectively.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in nuclear decommissioning trust funds. These marketable securities are reported on our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $32 million for 2005 and $24 million for 2004. We recorded, in AOCI, net unrealized gains on decommissioning trust investments of $10 million and $49 million for 2005 and 2004, respectively.

Dominion sponsors employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash that we will contribute to the employee benefit plans.

Risk Management Policies

We have operating procedures in place that are administered by experienced management to help ensure that proper internal controls are maintained. In addition, Dominion has established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries, including us. Dominion maintains credit policies that include the evaluation of a prospective counterparty s financial condition, collateral requirements where deemed necessary and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion also monitors the financial condition of existing counterparties on an ongoing basis.

Based on Dominion s credit policies and our December 31, 2005 provision for credit losses, management believes 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.

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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 1, 2006

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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 1, 2006

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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.

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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

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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

(shares in thousands, all other amounts in millions)	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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)**
					(10)	**(10)**

Net derivative gains hedging activities, net of $7 tax expense						
Total comprehensive income				**10**	**(12)**	**(2)**
Equity contribution by parent			**833**			**833**
Tax benefit from stock awards and stock options exercised			**3**			**3**
Dividends				**(470)**		**(470)**
Balance at December 31, 2005	**198**	**$ 3,388**	**$ 886**	**$ 842**	**$117**	**$ 5,233**

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

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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.

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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

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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.

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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.

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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.

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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

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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.

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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

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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

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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.

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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	Entitled Per Share

	Outstanding Shares (thousands)	Upon Liquidation
$ 5.00	107	$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	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

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

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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, to 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

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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).

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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.

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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.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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

On December 31, 2003, we adopted FIN 46R for our interests in special purpose entities referred to as SPEs. As a result, we have included in our Consolidated Financial Statements the SPE described in Note 3 to our Consolidated Financial Statements. Our Consolidated Balance Sheet as of December 31, 2005 reflects $350 million of net property, plant and equipment and deferred charges and $370 million of related debt attributable to the SPE. As this SPE is owned by unrelated parties, we do not have the authority to dictate or modify, and therefore cannot assess, the disclosure controls and procedures in place at this entity.

Item 9B. Other Information

None.

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Part III

Item 10. Directors and Executive Officers of the Registrant

(a) Information concerning directors of Virginia Electric and Power Company, each of whom is elected annually, is as follows:

Name and Age	Principal Occupation for Last Five Years and Directorships in Public Corporations	Year First Elected as Directors
Thomas F. Farrell, II (51)	Chairman of the Board of Directors and Chief Executive Officer of Virginia Electric and Power Company from February 2006 to date; President and Chief Executive Officer of Dominion from January 2006 to date; Chairman of the Board of Directors, President and Chief Executive Officer of Consolidated Natural Gas Company from January 2006 to date; President and Chief Operating Officer of Dominion from January 2004 to December 2005; President and Chief Operating Officer of Consolidated Natural Gas Company from January 2004 to December 2005; Executive Vice President of Dominion from March 1999 to December 2003; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to December 2003; Executive Vice President of Consolidated Natural Gas Company from January 2000 to December 2003; Chief Executive Officer of Virginia Electric and Power Company from May 1999 to December 2002.	1999
Thomas N. Chewning (60)	Executive Vice President and Chief Financial Officer of Dominion from May 1999 to date; Executive Vice President and Chief Financial Officer of Consolidated Natural Gas Company from January 2000 to date.	1999

Audit Committee Financial Experts

We are a wholly-owned subsidiary of Dominion Resources, Inc. As permitted by SEC rules, our Board of Directors serves as our Company s Audit Committee and is comprised entirely of executive officers of the Company. Our Board of Directors has determined that Thomas F. Farrell, II and Thomas N. Chewning are audit committee financial experts as defined by the SEC and, as executive officers of the Company, are not deemed independent.

(b) Information concerning the executive officers of Virginia Electric and Power Company, each of whom is elected annually is as follows:

Name and Age	Business Experience Past Five Years
Thomas F. Farrell, II (51)	Chairman of the Board of Directors and Chief Executive Officer of Virginia Electric and Power Company from February 2006 to date; President and Chief Executive Officer of Dominion from January 2006 to date; Chairman of the Board of Directors, President and Chief Executive Officer of Consolidated Natural Gas Company from January 2006 to date; President and Chief Operating Officer of Dominion from January 2004 to December 2005; President and Chief Operating Officer of Consolidated Natural Gas Company from January 2004 to December 2005; Executive Vice President of Dominion from March 1999 to December 2003; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to December 2003; Executive Vice President of Consolidated Natural Gas Company from January 2000 to December 2003; Chief Executive Officer of Virginia Electric and Power Company from May 1999 to December 2002.
Jay L. Johnson (59)	President and Chief Operating Officer-Delivery of Virginia Electric and Power Company from February 2006 to date; Executive Vice President of Dominion from January 2004 to date; President and Chief Executive Officer of Virginia Electric and Power Company from December 2002 to January 2006; Senior Vice President, Business Excellence, Dominion Energy, Inc. from September 2000 to December 2002.
Paul D. Koonce (46)	President and Chief Operating Officer-Energy of Virginia Electric and Power Company from February 2006 to date; Chief Executive Officer Energy of Virginia Electric and Power Company from January 2004 to January 2006; Chief Executive Officer Transmission of Virginia Electric and Power Company from January 2003 to December 2003; Senior Vice President Portfolio Management of Virginia Electric and Power Company from January 2000 to December 2002.
Mark F. McGettrick (48)	President and Chief Operating Officer-Generation of Virginia Electric and Power Company from February 2006 to date; President and Chief Executive Officer Generation of Virginia Electric and Power Company from January 2003 to

	January 2006; Senior Vice President and Chief Administrative Officer of Dominion from January 2002 to December 2002; President of Dominion Resources Services, Inc. from October 2002 to January 2003; Senior Vice President Customer Service and Metering of Virginia Electric and Power Company from January 2000 to December 2001.
Gary L. Sypolt (52)	President and Chief Operating Officer-Transmission of Virginia Electric and Power Company from February 2006 to date; President Transmission of Virginia Electric and Power Company from January 2003 to January 2006; Senior Vice President Transmission of Dominion Transmission, Inc., formerly CNG Transmission Corporation, from September 1999 to January 2003.
David A. Christian (51)	Senior Vice President Nuclear Operations and Chief Nuclear Officer from April 2000 to date.
David A. Heacock (48)	Senior Vice President Fossil & Hydro from April 2005 to date; Vice President Fossil and Hydro from December 2003 to April 2005; Site Vice President North Anna Power Station from April 2000 to December 2003.
G. Scott Hetzer (49)	Senior Vice President and Treasurer of Dominion from May 1999 to date; Senior Vice President and Treasurer of Virginia Electric and Power Company and Consolidated Natural Gas Company from January 2000 to date.
Thomas A. Hyman, Jr. (54)	Senior Vice President Customer Service and Planning of Virginia Electric and Power Company and Regulated Gas Distribution Companies of Consolidated Natural Gas Company from July 2003 to date; Senior Vice President Gas Distribution and Customer Services of Virginia Electric and Power Company from January 2002 to July 2003; Senior Vice President Gas Distribution and Customer Services of Regulated Gas Distribution Companies of Consolidated Natural Gas Company from December 2001 to July 2003; Senior Vice President Gas Distribution of Regulated Gas Distribution Companies of Consolidated Natural Gas Company from October 2000 to December 2001.

Name and Age	Business Experience Past Five Years
William R. Matthews (58)	Senior Vice President Nuclear Operations of Virginia Electric and Power Company from July 2002 to date; Vice President Nuclear Operations of Dominion Energy, Inc. from February 2002 to July 2002; Vice President and Senior Nuclear Executive Millstone of Dominion Energy, Inc. from May 2001 to February 2002; Vice President Nuclear Operations of Virginia Electric and Power Company from April 2000 to May 2001.
Jimmy D. Staton (45)	Senior Vice President Operations July 2003 to date; Senior Vice President Electric Distribution of Virginia Electric and Power Company from January 2003 to July 2003; Senior Vice President Electric Transmission and Electric Distribution of Virginia Electric and Power Company from December 2001 to January 2003; Senior Vice President Electric Distribution of Virginia Electric and Power Company from October 2000 to December 2001.
Steven A. Rogers (44)	Vice President, Controller and Principal Accounting Officer of Dominion and Consolidated Natural Gas Company and Vice President and Principal Accounting Officer of Virginia Electric and Power Company from June 2000 to date.

Effective February 1, 2006, Mr. Thomas F. Farrell, II was elected Chairman of the Board and Chief Executive Officer and Mr. Thomas N. Chewning was elected Executive Vice President and Chief Financial Officer of the Company.

Any service listed for Dominion, Dominion Energy, Inc., Consolidated Natural Gas Company and Dominion Transmission, Inc., reflects services at a parent, subsidiary or affiliate.

There is no family relationship between any of the persons named in response to Item 10.

In May 2004, Dominion sold its telecommunications subsidiary, Dominion Telecom, Inc., to a third party and Dominion Telecom, Inc. became Elantic Telecom, Inc. Subsequent to the sale, Elantic Telecom, Inc. filed for protection under Chapter 11 of the U.S. Federal Bankruptcy code.

Messrs. Johnson, Hetzer and Staton served as executive officers of Dominion Telecom, Inc. during the two years prior to its sale.

Code of Ethics

We have adopted a Code of Ethics that applies to our principal executive, financial and accounting officers as well as our employees. This Code of Ethics is available on the corporate governance section of Dominion s website (*www.dom.com*). You may also request a copy of the Code of Ethics, free of charge, by writing or telephoning the Company at: Corporate Secretary, 120 Tredegar Street, Richmond, Virginia 23219, Telephone (804) 819-2000. Any waivers or changes to our Code of Ethics will be posted on the Dominion website.

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Item 11. Executive Compensation

The Summary Compensation Table below includes compensation paid by the Company for services rendered in 2005, 2004 and 2003 to the Chief Executive Officers and the four other most highly compensated executive officers as determined under the SEC executive compensation disclosure rules.

Summary Compensation Table(1)

		Annual Compensation			Long Term Compensation	
	Year	Salary(2)	Bonus	Other Annual Compen-sation(3)	Restricted Stock Awards(4)	All Other Compen-sation(5)
Jay L. Johnson	**2005**	**$ 199,551**	**$ 159,641**	**$ 49,862**	**$**	**$ 49,791**
Chief Executive Officer & President	2004	176,364		73,271	302,955	61,395
	2003	182,333	145,866	29,884	315,318	43,674
Paul D. Koonce	**2005**	**100,047**	**78,528**	**331**		**7,284**
Chief Executive Officer Energy	2004	92,154		12,247	164,871	22,945
	2003	141,440	113,152	12,021	259,652	22,561
Mark F. McGettrick	**2005**	**218,039**	**176,591**	**814**		**19,340**
Chief Executive Officer & President Generation	2004	206,765		57,876	377,034	55,888
	2003	172,933	138,346	13,934	317,465	30,456
David A. Christian	**2005**	**193,649**	**135,554**	**868**		**16,294**
Senior Vice President Nuclear Operations &	2004	171,904		23,142	218,610	46,191
Chief Nuclear Officer	2003	153,919	96,969	12,040	195,359	26,025
David A. Heacock	**2005**	**154,844**	**78,354**	**33**		**28,027**
Senior Vice President Fossil & Hydro	2004	215,924		29,210	155,950	52,024
	2003	195,475	131,760	16,695	155,654	30,209
William R. Matthews	**2005**	**136,541**	**109,698**	**213**		**16,510**
Senior Vice President Nuclear Operations	2004	138,528	35,758	8,292	150,011	28,688
	2003	170,832	120,212	5,907	184,631	25,228
Jimmy D. Staton	**2005**	**150,551**	**75,275**			**8,809**
Senior Vice President Operations	2004	148,531	54,930	31,698	142,760	51,942
	2003	270,400	135,200	32,516	259,386	53,267

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. Compensation for the individuals listed in the table and related footnotes reflects only that portion which is allocated to the Company for each of the years reported and differences from year to year may reflect changes in allocation levels rather than changes in salary. Mr. Thomas F. Farrell, II was elected Chief Executive Officer of the Company, effective February 1, 2006, and therefore is not included in this table for 2005. Titles for Messrs. Johnson, Koonce and McGettrick reflect their Chief Executive Officer positions as of December 31, 2005.

(2) Salary Amounts shown may include vacation sold back to the Company.

(3) The amounts in this column include reimbursements for tax liability related to income imputed to the officers under Internal Revenue Service (IRS) rules for (i) certain travel and business expenses, (ii) a prior Executive Stock Purchase Tool Kit program and (iii) personal use of corporate aircraft. The tax reimbursement amounts for 2005 and 2004 were as follows: Mr. Johnson-2005: $9,232, 2004: $40,114 and Mr. McGettrick-2005: $814, 2004: $34,179.

For Messrs. Johnson and and McGettrick, the amounts in this column also include income related to perquisites (which are described under *Executive Perquisites and Other Business-Related Benefits*) and any imputed income related to company gifts. For Mr. Johnson, personal use of corporate aircraft represented more than 25% of total perquisites in 2005 and 2004 as follows: 2005-$25,024 and 2004-$21,026. Mr. McGettrick had the following individual items that represented more than 25% of total perquisites in 2004: vehicle allowance of $5,908 and club perquisite of $11,330, primarily for initiation fee paid on his behalf; he did not have any individual items that represented more than 25% of total perquisites in 2005.

All of the amounts listed in this column for Messrs. Koonce, Christian, Heacock, Matthews and Staton and the 2003 amounts for Messrs. Johnson and McGettrick are related to reimbursements for tax liabilities only.

(4) Dividends are paid on restricted stock. The aggregate number and value of each executive s Dominion restricted stock holdings at year-end, based on a December 31, 2005 closing price of $77.20 per share, were as follows:

Officer	Number of Restricted Shares	Value
Jay L. Johnson	10,216	$ 788,675
Paul D. Koonce	5,334	411,785
Mark F. McGettrick	10,805	834,146
David A. Christian	6,631	511,913
David A. Heacock	3,489	269,351
William R. Matthews	4,525	349,330
Jimmy D. Staton	4,596	354,811

(5) All Other Compensation The amounts listed for 2005 are as follows:

Officer	Employee Savings Plan Match	Company Match Above IRS Limits	Life Insurance Premiums	Took Kit Exchange*
Jay L. Johnson	$ 3,168	$ 2,818	$ 23,850	$ 19,955
Paul D. Koonce	1,654	1,290	4,340	
Mark F. McGettrick	4,468	4,254	10,618	
David A. Christian	3,979	3,767	8,548	
David A. Heacock	5,582	612	4,203	17,630
William R. Matthews	4,344	1,117	11,049	
Jimmy D. Staton	3,309	1,207	4,293	

* Messrs. Johnson and Heacock elected to exchange a portion of their 2005 bonuses for shares of Dominion stock under the Executive Stock Purchase Tool Kit. Under the terms of the Tool Kit, they each received an amount equal to 25% of the cash bonus exchanged and the additional amount was also exchanged for Dominion stock. Total shares acquired under the Tool Kit are as follows: Johnson-1,416 shares and Heacock-917 shares.

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Aggregated Option/SAR Exercises in Last Fiscal Year(1)

And FY-End Option/SAR Values

	Shares Acquired on Exercise	Value Realized(2)	Number of Securities Underlying Unexercised Options/SARs At FY-End		Value of Unexercised In-the-Money Options/SARs At FY-End(3)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Jay L. Johnson		$	50,290		$867,000	$
Paul D. Koonce	26,260	316,435	26,260		452,722	
Mark F. McGettrick	17,730	267,015	35,460		611,333	
David A. Christian	94,740	847,241				
David A. Heacock	13,290	133,432	26,580		458,239	
William R. Matthews	31,032	276,629	17,240		204,292	
Jimmy D. Staton	17,510	179,855	35,020		603,748	

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. Dominion options and shares acquired on exercise for individuals listed in the table reflect only that portion which is allocated to the Company.
(2) Spread between the market value at exercise minus the exercise price.
(3) Spread between the market value at year end minus the exercise price. Year-end stock price was $77.20 per share.

Executive Compensation

Dominion s Organization, Compensation and Nominating Committee (Dominion s Committee) oversees the Company s executive compensation program. Dominion s Committee often meets without management present and, at least once a year, discusses directly with its independent compensation consultant a number of matters.

Each year, Dominion s Committee reviews and discusses trends in executive compensation including legal, regulatory and other developments, and considers all components of our executive compensation program generally. Periodically, Dominion s Committee engages its consultant or outside counsel to perform more detailed reviews of certain programs, with a report directly back to the Committee.

Executive Compensation Philosophy

Generally, the Company s compensation philosophy is to administer an executive compensation program that attracts, motivates and retains a superior management team, while ensuring that the annual and long-term incentive programs and benefits align management s financial success with that of the Company. We believe in putting a substantial portion of compensation at risk based on performance goals established by Dominion s Committee. While the Company benchmarks and sets general goals of compensation levels as compared to Dominion s peer group of companies, it administers a program that fits the needs and requirements of the Company. This takes into consideration internal equity and other concerns and does not try to match up compensation levels with the peer surveys for senior officers, but uses such surveys as a check for compensation decisions that make good business sense for the Company.

Base Salary

While the base salary component of the Company s program generally is targeted at or slightly above market median, the Company s primary goal is to compensate the Company s executives at a level that best achieves our compensation philosophy and addresses internal equity issues, whether this results in actual pay that may be slightly higher or lower than our stated target. Dominion s Committee has found that proxy and survey results for particular positions can vary greatly from year to year, and will consider market trends for certain positions over a period of years rather than a one-year snapshot in setting compensation for such positions.

Company officers did not receive salary increases in 2002 and 2004, other than in cases of promotions or certain market based adjustments. As a result, base salaries had generally fallen behind targeted levels, and Dominion s Committee recommended a general base salary increase of 6% for officers for 2005. Certain officers received increases in excess of 6% as necessary for market-based and performance reasons. In particular, salaries for many senior executives had fallen below the market median for their positions, and on average the base salary increase for this group was 14%.

Annual Incentives

Under the annual incentive program, if goals are achieved or exceeded, the executive s total cash compensation for the year is targeted to be at or slightly above market median, with the same stipulation expressed above.

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Under the Company s annual incentive program, Dominion s Committee establishes target awards for each executive. These target awards are expressed as a percentage of the individual executive s base salary (for example, 50% x base salary). The target award is the amount of cash that will be paid, at year-end, if the executive achieves 100% of the goals established at the beginning of the year, and the plan is fully funded.

The 2005 Annual Incentive Plan (the Plan) was to be fully funded if Dominion met its 2005 consolidated operating earnings target. For a full payout under the Plan, each executive also had to meet certain performance criteria including consolidated and business unit financial goals and operating, stewardship and Six Sigma goals. Each executive s goals were weighted according to his or her responsibilities.

Primarily due to Hurricanes Rita and Katrina, Dominion s operating earnings did not meet the funding goal. However, after some deliberation, Dominion s Committee exercised discretion for both the funding and payout components of the annual incentive program, and approved 100% payout of bonuses for 2005, after considering a number of relevant factors.

Long-term Incentives

The Company s long-term incentive programs continue to play a critical role in its compensation practices and philosophy of aligning the interests of our officers with those of the Company while rewarding performance. However, in light of our 2003 and 2004 restricted stock grants, and other considerations, Dominion s Committee did not make an officer-wide long-term equity grant in 2005 except for some individual recruiting or retention grants to certain officers. Dominion s Committee plans to transition to annual long-term grants in 2006, incorporating a performance-contingent component for a significant portion of the overall long-term program.

Retirement Plans

The table below shows the estimated annual straight life benefit that we would pay to an executive at normal retirement age (65) under the benefit formula of the Pension Plan including any make-whole amounts under the Benefit Restoration Plan described below.

2005 Estimated Annual Benefits Payable Upon Retirement

	Credited Years of Service			
Final Average Earnings	15	20	25	30
$185,000	$49,740	$66,240	$82,800	$99,360
$200,000	54,300	72,360	90,420	108,480
$250,000	69,060	92,160	115,320	138,480
$300,000	84,540	112,800	141,000	169,200
$350,000	99,660	132,960	166,260	199,500
$400,000	114,780	153,120	191,520	229,860
$450,000	129,900	173,340	216,780	260,160
$500,000	145,020	193,560	242,040	290,520

Pension Plan

Benefits under the Pension Plan are based on:

- highest average base salary over a consecutive five-year period during the ten years preceding retirement;
- years of credited service;
- age at retirement; and
- the offset of Social Security benefits.

We provide a Special Retirement Account (SRA) feature to the Pension Plan. This account is credited with two percent of an employee s base salary earned each year. Account balances are credited with earnings based on the 30-year Treasury rate and may be taken as a lump sum or an annuity at retirement. The above table includes the effect of SRA earnings converted to an annual annuity.

Benefit Restoration Plan

The Internal Revenue Code imposes certain limits related to Pension Plan benefits. Any resulting reduction in an executive s Pension Plan benefit will be compensated for under the Benefit Restoration Plan. The table above reflects any amounts payable under both the Pension Plan and the Benefit Restoration Plan, including the effect of SRA earnings from salaries in excess of IRS limits.

In addition, certain officers, if they reach a specified age while still employed, will be credited with additional years of service. Mr. Johnson will receive a total of 20 years of credited service after 10 years of continuous employment. Mr. McGettrick will receive 5 years of additional age and service if he serves as an officer until his 50th birthday. Mr. Matthews will receive a total of 30 years of credited service if he serves as an officer until age 60. Each of the named executives in the Summary Compensation Table, except for Messrs. Johnson and Koonce, will have 30 years of credited service at age 60. Mr. Staton will have 30 years of credited service at age 60 $^{1}/2$.

This Plan was frozen as of December 31, 2004 and the New Benefit Restoration Plan was implemented effective January 1, 2005. There was no change in the amount of benefits as a result of this change.

Executive Supplemental Retirement Plan

The Supplemental Retirement Plan provides an annual retirement benefit equal to 25% of a participant s final cash compensation (base pay plus target annual bonus). To retire with full benefits under the Supplemental Retirement Plan, an executive must be 55 years old and have been employed by the Company for at least five years. Benefits under the plan are provided either as a lump sum cash payment at retirement or as a monthly annuity paid out, typically, over 10 years. Under this program, Messrs. McGettrick, Christian and Matthews will receive a lifetime benefit if they serve as an officer until age 60; Mr. Koonce will receive a lifetime benefit if he serves as an officer until age 50; and Mr. Johnson will receive a lifetime benefit after 10 years of service. Based on 2005 cash compensation, the estimated annual benefit under this plan for executives named in the Summary Compensation Table are: Mr. Johnson $89,798; Mr. McGettrick $99,332; Mr. Koonce $44,172; Mr. Christian $82,301; Mr. Heacock $58,766; Mr. Matthews $51,203; and Mr. Staton $56,457.

This Plan was frozen as of December 31, 2004 and the New Executive Supplemental Retirement Plan was implemented effective January 1, 2005. There is no change in the benefit provided as a result of this change.

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Other Executive Agreements and Arrangements

Companies that are in a rapidly changing industry such as ours require the expertise and loyalty of exceptional executives. Not only is the business itself competitive, but so is the demand for such executives. In order to secure the continued services and focus of key management executives, we have entered into the following agreements with them, including those named in the Summary Compensation Table.

Continuity Agreements

The Company has entered into employment continuity agreements with executives named in the Summary Compensation Table, which provide benefits in the event of a change in control. Each agreement has a three-year term and is automatically extended for an additional year, unless cancelled by the Company.

The agreement for each executive provides for the continuation of salary and benefits for a maximum period of three years after (1) a change in control, (2) termination without cause following a change in control, or (3) a termination after a reduction of responsibilities, salary or incentives following a change in control (if the executive gives 60 days notice). Under the agreements, each executive would receive the following: (1) an annual base salary not less than the executive s highest annual base salary during the twelve months preceding the change of control, (2) an annual bonus not less than the highest maximum annual bonus available to the executive during the three years preceding the change of control and (3) continued eligibility for awards under company incentive, savings and benefit plans provided to senior management. In addition, any outstanding stock options and other forms of stock awards will fully vest upon a change in control. Upon a covered executive s death or disability, or if the executive is terminated without cause or terminates after a reduction of responsibility, salary or incentives, the agreement provides for a lump sum severance payment equal to three times base salary plus annual bonus, together with the full vesting of benefits under the company s benefit plans. If a covered executive is terminated without cause or terminates after a reduction of responsibility, salary or incentives, the executive also will receive full vesting of any outstanding stock options and five years of additional credit for age and service. The agreements indemnify the executives for potential penalties related to the Internal Revenue Code and fees associated with the enforcement of the agreements. If an executive is terminated for cause, the agreements are not effective.

For purposes of the continuity agreements described above, a change of control shall be deemed to have occurred if (i) any person or group becomes a beneficial owner of 20% or more of the combined voting power of Dominion voting stock or (ii) as a direct or indirect result of, or in connection with, a cash tender or exchange offer, merger or other business combination, sale of assets, or contested election, the Directors constituting the Dominion Board before any such transactions cease to represent a majority of Dominion or its successor s Board within two years after the last of such transactions.

Other Arrangements

Messrs. Christian and Matthews have entered into Supplemental Agreements with Dominion whereby they have also agreed not to compete with the activities of Dominion or solicit any Dominion employees in consideration of their receipt of enhanced benefits under the Supplemental Retirement Plans described above.

Executive Stock Purchase Programs

Dominion has stock ownership guidelines for its officers and officers of its subsidiaries and provides tools to assist management in obtaining their targeted ownership levels.

Dominion s Executive Stock Purchase Tool Kit consists of two programs to encourage ownership of Dominion stock by executives. Executives who participate in one or more of the Tool Kit programs to achieve their stock ownership target levels receive bonus shares for up to twenty-five percent of the value of their investments in Dominion stock. The programs are: (i) a bonus exchange program, where goal-based stock is issued in exchange for annual incentive payouts; and (ii) a stock acquisition program, with participants making one-time or periodic purchases of Dominion stock through Dominion Direct®.

Executive Perquisites and Other Business-Related Benefits

We offer a limited number of perquisites to our executives. We provide an allowance of up to $9,500 a year to our officers for financial planning and/or physical well being services. This benefit is valued for our perquisite calculation and for tax purposes based on the actual dollar amount paid on the officers behalf for the services provided.

In addition, we provide our officers with a company-leased vehicle. The company makes the lease payment on the officer s behalf up to the applicable allowance limit for the officer. If the lease payment exceeds the allowance, the officer pays for any excess amounts on such vehicle personally. Insurance, gas and maintenance are also provided for these vehicles. The officer is taxed on any personal use of the vehicle, and any personal use is also included in the perquisite calculation. Finally, officers are provided with a luncheon or club membership (or memberships in the case of a few officers). They are taxed on all applicable dues and fees associated with club membership, and such amounts are included in the perquisite calculation. Certain senior and nuclear officers also are provided with security systems at their home residence. We do not consider these systems to be a perquisite, but instead view them as a business need for a limited number of our executives. However, we have included these costs in our calculation of perquisites since 2004.

Finally, as disclosed in Footnote 4 to the Summary Compensation Table, in limited circumstances our executive officers may use company aircraft for personal travel.

Compensation of Directors

All of our Directors, who are officers of the Company or Dominion, do not receive any compensation for services they provide as directors.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The table below sets forth as of February 1, 2006, except as noted, the number of shares of Dominion common stock owned by Directors and the executive officers named in the Summary Compensation Table.

	Beneficial Share Ownership				
			Exercisable		
		Restricted	Stock		Deferred
Name	Shares	Shares	Options	Total	Compensation[1]
Thomas N. Chewning	114,256	57,410	450,000	621,666	185
Thomas F. Farrell, II[2]	130,563	86,726	600,000	817,289	
Jay L. Johnson	11,424	20,314	100,000	131,738	4,642
Mark F. McGettrick	25,376	20,314	66,667	112,357	5,592
Paul D. Koonce	17,681	20,314	100,000	137,995	6,101
Jimmy D. Staton	5,552	8,749	66,667	80,968	12,307
David A. Heacock	12,589	5,250	40,000	57,839	
William R. Matthews	17,208	8,749	33,333	59,290	3,839
David A. Christian	23,397	13,999		37,396	
All directors and executive officers as a group (13 persons)[3]	425,986	278,705	1,696,668	2,401,359	44,868

(1) Amounts in this column represent share equivalents under a deferred compensation plan and do not have voting rights.
(2) Mr. Farrell disclaims ownership for 399 shares.
(3) All directors and executive officers as a group own less than one percent of the number of Dominion common shares outstanding at February 1, 2006. No individual executive officer or director owns more than one percent of the shares outstanding.

Item 13. Certain Relationships and Related Transactions

None.

Item 14. Principal Accountant Fees and Services

The following table presents fees paid to Deloitte & Touche LLP for the fiscal years ended December 31, 2005 and 2004.

Type of Fees (millions)	**2005**	2004
Audit fees	**$ 1.04**	$ 0.85
Audit-related	**0.27**	0.26
Tax fees	**0.61**	0.70
All other fees		
	$ 1.92	$ 1.81

Audit Fees are for the audit and review of our financial statements in accordance with generally accepted auditing standards, including comfort letters, statutory and regulatory audits, consents and services related to SEC matters.

Audit-Related Fees are for assurance and related services that are related to the audit or review of our financial statements, including employee benefit plan audits, due diligence services and financial accounting and reporting consultation.

Tax Fees reflect the settlement of outstanding arrangements related to tax planning assistance.

In 2003, our Board adopted a pre-approval policy for Deloitte & Touche LLP services and fees. Attached to the policy is a schedule that details the services to be provided and an estimated range of fees to be charged for such services. In December 2005, Dominion s Audit Committee approved the services and fees for 2006.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements

See Index on page 24.

All schedules are omitted because they are not applicable, or the required information is either not material or is shown in the financial statements or the related notes.

2. Exhibits

3.1	Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-2255, incorporated by reference).
3.2	Bylaws, as amended, as in effect on April 28, 2000 (Exhibit 3, Form 10-Q for the period ended March 31, 2000, File No. 1-2255, incorporated by reference).
4	Virginia Electric and Power Company agrees to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of its total consolidated assets.
4.1	See Exhibit 3.1 above.
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Sixty-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 2, 1991, File No. 1-2255, incorporated by reference); Seventieth Supplemental Indenture, (Exhibit 4(iii), Form 8-K, dated February 25, 1992, File No. 1-2255, incorporated by reference); Seventy-First Supplemental Indenture (Exhibit 4(i)) and Seventy-Second Supplemental Indenture, (Exhibit 4(ii), Form 8-K, dated July 7, 1992, File No. 1-2255, incorporated by reference); Seventy-Third Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 6, 1992, File No. 1-2255, incorporated by reference); Seventy-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Fifth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 6, 1993, File No. 1-2255, incorporated by reference); Seventy-Sixth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated April 21, 1993, File No. 1-2255, incorporated by reference); Seventy-Seventh Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated June 8, 1993, File No. 1-2255, incorporated by reference); Seventy-Eighth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Ninth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Eightieth Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated October 12, 1993, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture, (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Eighty-Second Supplemental Indenture, (Exhibit 4(i), Form 8-K, dated January 18, 1994, File No. 1-2255, incorporated by reference); Eighty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference); Eighty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated March 23, 1995, File No. 1-2255, incorporated by reference); and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, File No. 1-2255, incorporated by reference).
4.3	Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Chemical Bank), as Trustee (Exhibit 4(a), Form S-3 Registration Statement File No. 333-20561 as filed on January 28, 1997, incorporated by reference), Form of Second Supplemental Indenture (Exhibit 4.6, Form 8-K filed August 20, 2002, No. 1-2255, incorporated by reference).
4.4	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and JP Morgan Chase Bank (formerly The Chase Manhattan Bank) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255,

	incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference).
4.5	Virginia Electric and Power Company agrees to furnish to the Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of Dominion Resources, Inc. s total consolidated assets.
10.1	Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(v), Form 10-K for the fiscal year ended December 31, 1997, File No. 1-8489, incorporated by reference).
10.2	Services Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).

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10.3	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255, incorporated by reference).
10.4	$2.5 billion Five-Year Revolving Credit Agreement, dated as of May 12, 2005, among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A., as Syndication Agent, Barclays Bank PLC, The Bank of Nova Scotia and Wachovia Bank, National Association, as Co-Documentation Agents, and other lenders as named herein (Exhibit 10.1, Form 8-K filed May 18, 2005, File No. 1-8489, incorporated by reference).
10.5	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Dominion (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003, File No. 1-2255, incorporated by reference.
10.6*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.7*	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997, as amended and restated effective July 20, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference).
10.8*	Dominion Resources, Inc. 2005 Incentive Compensation Plan (Exhibit 10, Form 8-K filed March 3, 2004, File No. 1-8489, incorporated by reference).
10.9*	Dominion Resources, Inc. Executive Stock Purchase and Loan Plan II, dated February 15, 2000 (Exhibit 10.10, Form 10-K for the fiscal year ended December 31, 2002, File No. 1-2255, incorporated by reference).
10.10*	Form of Employment Continuity Agreement for certain officers of the Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003, File No. 1-2255, incorporated by reference).
10.11*	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (Exhibit 10(iii), Form 10-Q for the quarter ended June 30, 1997, File No. 1-8489, incorporated by reference).
10.12*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.13*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.14*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, effective January 1, 2005 (Exhibit 10.8, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 19, 2006 (filed herewith).
10.15*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, effective January 1, 2005 (Exhibit 10.9, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.16*	Dominion Resources, Inc. Leadership Stock Option Plan, effective July 1, 2000, as amended and restated effective July 20, 2001 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference).
10.17*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated December 16, 2005 (Exhibit 10.12, Form 8-K filed December 16, 2005, File No. 1-8489, incorporated by reference).
10.18*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
12.1	Ratio of earnings to fixed charges (filed herewith).
12.2	Ratio of earnings to fixed charges and dividends (filed herewith).
21	Subsidiaries of the Registrant (filed herewith).
23.1	Consent of Deloitte & Touche LLP (filed herewith).
23.2	Consent of Jackson & Kelly PLLC (filed herewith).
23.3	Consent of McGuire Woods 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).

* Indicates management contract or compensatory plan or arrangement.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ THOMAS F. FARRELL, II

(Thomas F. Farrell, II,

Chairman of the Board of Directors and Chief Executive Officer)

Date: March 2, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 2nd day of March, 2006.

Signature	Title
/s/ THOMAS F. FARRELL, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ THOMAS N. CHEWNING **Thomas N. Chewning**	Director, Executive Vice President and Chief Financial Officer
/s/ STEVEN A. ROGERS **Steven A. Rogers**	Vice President (Principal Accounting Officer)