VIRGINIA ELECTRIC & POWER CO
Form 10-K
February 28, 2007
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UNITED STATES

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, 2006

OR

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

Commission File Number 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

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

(804) 819-2000

(Registrant s telephone number)

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

Title of Each Class	Name of Each Exchange on Which Registered
Preferred Stock (cumulative), $100 par value, $5.00 dividend	New York Stock Exchange
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, 2007, 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 I

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, municipalities and into wholesale electricity markets. 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, 2006, we had approximately 6,900 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 120 Tredegar 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 and customer service businesses. 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 jurisdictional 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 s electric distribution network includes approximately 55,000 miles of distribution lines, exclusive of service level lines in Virginia and North Carolina. The rights-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 ENERGY SUPPLY

Delivery s supply of electricity to serve retail customers is produced or procured by the Generation segment. See *Generation* for additional information.

SEASONALITY

Delivery s business varies seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

Energy

Energy includes our regulated electric transmission system serving Virginia and northeastern North Carolina. In 2005, we became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and integrated our electric transmission facilities into the PJM wholesale electricity markets.

COMPETITION

Since the integration of our electric transmission facilities into PJM, our electric transmission services are administered by PJM and are no longer subject to competition in relation to transmission service provided to customers within the PJM region.

REGULATION

Energy s electric transmission rates, tariffs and terms of service are subject to regulation by the Federal Energy Regulatory Commission (FERC). Electric transmission siting authority remains the exclusive jurisdiction of the Virginia and North Carolina Commissions. However, the Energy Policy Act of 2005 (EPACT) provides FERC with certain limited backstop authority for transmission siting, the implications of which remain unclear. 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, any surplus capacity that may exist in these lines.

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.

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kV transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 70 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is

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an approximately 56-mile 500-kV transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals.

SEASONALITY

Energy s business varies seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

Generation

Generation includes our portfolio of electric generation facilities, power purchase agreements 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 energy and 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 any significant extent. See *Regulation State Regulations*. Currently, North Carolina does not offer retail choice to electric customers.

REGULATION

The operations of our Generation segment are subject to regulation by the Virginia Commission, the North Carolina Commission, FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), the Department of Energy (DOE), the Army Corps of Engineers and other federal, state and local authorities.

PROPERTIES

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

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation in the future. We currently have plans to restart our Hopewell plant in 2007, a 63-megawatt (Mw) (at net summer capability) coal burning plant located in Hopewell, Virginia which has been out of service since 2002, and we are evaluating a 290-Mw (at net summer capability) expansion of our Ladysmith site in Ladysmith, Virginia. We are also leading a consortium of companies that are considering building a 500 to 600-Mw coal-fired plant in southwest Virginia. We will continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future.

SOURCES OF ENERGY SUPPLY

Generation uses a variety of fuels to power our electric generation, as described below. See *Segment Results of Operations Generation* in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation (MD&A) for a summary of our generation output by energy source.

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 which are dependent on the market environment. 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 short-term spot agreements.

Generation s natural gas and oil supply is obtained from various sources including: purchases from major and independent producers in the Mid-Continent and Gulf Coast regions; purchases from local producers in the Appalachian area; purchases from gas marketers; and withdrawals from underground storage fields owned by Dominion or third parties. Generation manages a portfolio of natural gas transportation contracts (capacity) that allows flexibility in delivering natural gas to our gas turbine fleet, while minimizing costs.

SEASONALITY

Sales of electricity for the Generation segment vary seasonally as a result of the impact of changes in temperature on demand by residential and commercial customers for electricity to meet cooling and heating needs.

NUCLEAR DECOMMISSIONING

Generation has four licensed, operating nuclear reactors at its Surry and North Anna plants in Virginia that serve our customers. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power plant once operations have ceased, in accordance with standards established by the 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 $1.8 billion in 2006 dollars and is primarily based upon site-specific studies completed in 2006. The current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire. We expect to decommission the Surry and North Anna units during the period 2032 to 2059.

	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 (2006 dollars)	$ 457	$ 484	$ 436	$ 458	$ 1,835
Funds in trusts at December 31, 2006	361	356	296	280	1,293
2006 contributions to trusts	1.4	1.5	1.0	0.9	4.8

Corporate

We also have a Corporate segment. Corporate includes our corporate and other functions and specific items attributable to our operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in 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 Notes 1, 8 and 25 to our Consolidated Financial Statements.

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REGULATION

We are subject to regulation by the Virginia Commission, the North Carolina Commission, the Securities and Exchange Commission (SEC), FERC, the EPA, the 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 which authorize 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. In addition, the Virginia Commission and the North Carolina Commission regulate our transactions with affiliates, transfers of certain facilities and issuance of securities.

Rates

Historically, our rates have been based on the cost of providing traditional bundled electric service (i.e., the combination of transmission, distribution and generation services). As a result of the Virginia Electric Utility Restructuring Act enacted in 1999 (1999 Virginia Restructuring Act), in Virginia, rates have been transitioning to unbundled cost-based rates for transmission and distribution services, and to market pricing for generation services, including retail choice for our customers. In North Carolina, rates are still based on the cost of providing traditional bundled electric service; however, our base rates are currently subject to a rate moratorium as described below.

The following is a discussion of our current rate structure; however, such structure is subject to change under proposed new restructuring legislation described under *Status of Electric Restructuring in Virginia.*

Virginia We provide retail electric service in Virginia at unbundled rates. Our base rates are capped at 1999 levels until the sooner of (1) the end of a transition period (now December 31, 2010) or (2) a Virginia Commission order finding that a competitive market for generation exists in the Commonwealth. In 2004, the Virginia fuel factor statute was amended to lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction. However, in May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months (thus allowing deferred fuel accounting for these periods); and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, 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. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

North Carolina In connection with the North Carolina Commission s approval of Dominion s acquisition of Consolidated Natural Gas Company (CNG) in 2000, 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 jurisdictional base rates should not be reduced. The rate case was filed in September 2004, and in March 2005, the North Carolina Commission approved a settlement that included a prospective $12 million 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.

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

The 1999 Virginia Restructuring Act established a plan to restructure the electric utility industry in Virginia. In general, this legislation provided for a transition from bundled cost-based rates for regulated electric service to unbundled cost-based rates for transmission and distribution services and to market pricing for generation services, including retail choice for our customers. The 1999 Virginia Restructuring Act addressed capped base rates, RTO participation, retail choice, stranded costs recovery and functional separation of an electric utility s generation from its transmission and distribution operations.

Retail choice was made available to all of our Virginia regulated electric customers, commencing on January 1, 2003. We have separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation division and other divisions operate independently and prevent cross-subsidies between our generation division and other divisions. Additionally, in 2005, we became a member of PJM, an RTO, and have integrated our electric transmission facilities into the PJM wholesale electricity markets. Under the 1999 Virginia Restructuring Act, our base rates have been capped until December 31, 2010, unless modified earlier as previously discussed in *Rates*.

2004 amendments to the 1999 Virginia Restructuring Act addressed a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia.

2007 VIRGINIA RESTRUCTURING ACT AMENDMENTS

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

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sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern United States (U.S.), with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the Consumer Price Index in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the Consumer Price Index;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Governor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Governor s signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

Retail Access Pilot Programs

Three retail access pilot programs were approved by the Virginia Commission in 2003, and continue to be available to customers. There are currently six competitive suppliers and six aggregators registered with us and licensed to supply electricity to customers in Virginia. However, the current relationship between capped rates and market prices makes switching suppliers unlikely.

Federal Regulations

FEDERAL ENERGY REGULATORY COMMISSION

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. We sell electricity in the wholesale market under our market-based sales tariffs 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. Various proceedings that may have a significant effect on electric transmission service rates within the PJM region are ongoing at FERC. The outcome of these cases cannot be determined with any certainty at this point in time.

We are also subject to FERC s Standards of Conduct that govern conduct between interstate gas and electricity transmission 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.

EPACT included provisions to create an Electric Reliability Organization (ERO). The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. In 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the ERO beginning on January 1, 2007. In late 2006, FERC also issued an initial order approving many reliability standards, also to go into effect on January 1, 2007. FERC has proposed that beginning on June 1, 2007, entities that violate standards will be subject to fines of between $1 thousand and $1 million per day, depending upon the nature and severity of the violation.

We have planned and operated our facilities in compliance with earlier NERC voluntary standards for many years and are fully aware of the new requirements. We participate on various NERC committees, track development and implementation of standards, and maintain proper compliance registration with NERC s regional organizations. While we expect that there will be some additional cost involved in maintaining compliance as standards evolve, we do not expect a need for major expenditures beyond the normal course of business.

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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 Note 21 to our Consolidated Financial Statements.

The Clean Air Act (CAA) is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation s air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of our facilities are subject to the CAA s permitting and other requirements. For example, the EPA has established the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO_2), nitrogen oxide (NO_X) and mercury emissions from electric generating facilities. 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.

In 1997, the U.S. signed an International Protocol (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% during the period 2002 through 2012. We expect continuing legislative efforts in the U.S. Congress seeking to target the reductions of greenhouse gas emissions.

The Clean Water Act (CWA) is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. We must comply with all aspects of the CWA programs at our operating facilities. Provisions also include requirements that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Additional programs under the CWA address the impact of thermal discharges to surface waters.

From time to time, we may be identified as a potentially responsible party (PRP) to a Superfund site. See Note 21 to our Consolidated Financial Statements for a description of our exposure relating to our identification as a PRP. We do not believe that any currently identified sites will result in significant liabilities.

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 our 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, that action could result in substantial increases in the cost of operating and maintaining our nuclear generating units.

The NRC also requires us to decontaminate our 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 the decommissioning trusts that have been established for this purpose, see *Generation Nuclear Decommissioning* and Note 9 to our Consolidated Financial Statements.

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 require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. Management believes that 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 1999 Virginia Restructuring Act, as amended, our base rates remain capped through December 31, 2010 unless sooner modified or terminated. Although this 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 risks include exposure to stranded costs, future environmental compliance requirements, certain tax law changes, costs related to hurricanes or other weather events,

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inflation, the cost of obtaining replacement power during unplanned plant outages and increased capital costs.

In addition, our current Virginia fuel factor provisions are locked-in until July 1, 2007, with no deferred fuel accounting. As a result, until July 1, 2007 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. Annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted for three twelve-month periods beginning July 1, 2007. The Virginia Commission is authorized to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008. There will also be an adjustment for one six-month period beginning July 1, 2010. Beginning July 1, 2007, our risk of under-recovering prudently incurred expenses until July 1, 2010 is greatly diminished. Because there will be no adjustment to account for differences between projections and actual recovery of fuel costs at the end of the six-month period beginning July 1, 2010, we will be exposed to fuel price and other risks during that period. Further, after December 31, 2010 (or upon the earlier termination of capped rates), fuel cost recovery provisions will cease and we will be exposed to the fuel price and other related risks as described above.

The foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 legislative amendments. The proposed legislation would end capped rates on December 31, 2008. The proposed legislation also calls for annual fuel cost recovery proceedings beginning July 1, 2007 and continuing thereafter. The first annual increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected in the years 2008 through 2010, as described under *Status of Electric Restructuring in Virginia* in MD&A. The Governor of Virginia has until March 26, 2007 to sign, propose amendments to, or veto the proposed legislation. We cannot predict the outcome of the legislation at this time.

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 mitigate 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 fully 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.

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, 2007, our senior unsecured debt is rated BBB, positive outlook, by Standard & Poor s Ratings Services (Standard & Poor s); Baa1, stable outlook, 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. Our business 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 operating results.

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; however, only $215 million of these bonds were outstanding at December 31, 2006 and the bonds will mature on July 1, 2007.

We share our principal office in Richmond, Virginia, which is owned by our parent company, 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 Generation segment s generating units and capability, as of December 31, 2006:

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
Low Moor (CT)	Covington, VA	Oil	48
Northern Neck (CT)	Lively, VA	Oil	44
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	300
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	1,656(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Wood	80
Other	Various	Various	15

		15,552
Purchased Capacity		2,076
	Total Capacity	**17,628**

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

(a) Excludes 11.6% undivided interest owned by Old Dominion Electric Cooperative (ODEC).
(b) Excludes 50% undivided interest owned by ODEC.
(c) Includes a generating unit that we operate under a leasing arrangement.
(d) Excludes 40% 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 various environmental, rate matters and other 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. Restrictions on our payment of dividends are discussed in Note 19 to our Consolidated Financial Statements. We paid quarterly cash dividends on our common stock as follows:

(millions)	1st	2nd	3rd	4th	Total
2006	**$ 76**	**$ 63**	**$ 134**	**$ 76**	**$ 349**
2005	131	107	216		454

ITEM 6. SELECTED FINANCIAL DATA

(millions)	2006	2005(1)	2004(2)	2003(3)	2002
Operating revenue	**$ 5,603**	$ 5,712	$ 5,371	$ 5,191	$ 5,003
Income from continuing operations before cumulative effect of changes in accounting principles	**478**	485	590	556	801
Income (loss) from discontinued operations, net of tax(4)		(471)	(159)	26	(28)
Cumulative effect of changes in accounting principles, net of tax		(4)		(21)	
Net income	**478**	10	431	561	773
Balance available for common stock	**462**	(6)	415	546	757
Total assets	**15,683**	15,449	17,318	16,884	15,588
Long-term debt(5)	**3,619**	3,888	4,958	4,744	3,794
Preferred securities of subsidiary trust(5)					400

(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 the following accounting standards that resulted in the recognition of the cumulative effect of changes in accounting principles:

- Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*;
- 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*;
- 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;* and
- Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R).

(4) 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.

(5) Upon adoption of FIN 46R 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.

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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

Our MD&A consists of the following information:

- Forward-Looking Statements
- Introduction
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Liquidity and Capital Resources
- Future Issues and Other Matters

FORWARD-LOOKING STATEMENTS

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and winter storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments, including a movement towards a hybrid form of regulation, and changes to 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 trusts;
- Fluctuations in interest rates;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Changes in rules for regional transmission organizations (RTOs) in which we participate, including changes in rate designs and new and evolving capacity models;
- Changes to our ability to recover investments made under traditional regulation through rates; 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 for sale 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.

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 regulated electric distribution and customer service businesses. Our electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina.

Revenue provided by our 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 serving Virginia and northeastern North Carolina. In 2005, we

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became a member of PJM Interconnection, LLC (PJM), an RTO, and integrated our electric transmission facilities into the PJM wholesale electricity markets.

Revenue provided by our 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 in earnings results from changes in rates and the demand for services, which is primarily weather dependent.

Generation includes our portfolio of electric generating facilities, power purchase agreements 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 energy and capacity needs for our utility system resources.

Generation s earnings primarily 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, at which time fuel rates will be adjusted annually as discussed in *Status of Electric Restructuring in Virginia* in *Future Issues and Other Matters*.

Changes in our utility operating costs, particularly with respect to fuel and purchased power, relative to costs used to establish capped rates, will impact our earnings. Variability in earnings 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, and specific items attributable to our primary operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments, including the net impact of Virginia Power Energy Marketing, Inc. (VPEM) prior to its transfer to Dominion.

On December 31, 2005, we completed the 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 by acting as an agent for one of our other indirect wholly-owned subsidiaries. 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 in 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 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.

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.

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 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 in our Consolidated Balance Sheets were measured during a period of historically low interest rates.

The impact on measurements of new AROs, or remeasurements of existing AROs, using different rates in the future, may be significant. When we revise any assumptions used to calculate the fair value of existing AROs, we adjust the carrying amount of both the ARO liability and the related long-lived asset. We accrete the ARO liability to reflect the passage of time. In 2006, 2005 and 2004, we recognized $40 million, $44 million and $42 million, respectively, of accretion and expect to incur $36 million in 2007.

A significant portion of our AROs relate to the future decommissioning of our nuclear facilities. At December 31, 2006, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $603 million, representing approximately 94% 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 specialists periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. We obtained updated cost studies for both of our nuclear plants in 2006 which reflected increases in base year costs. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, our cost estimates include cost escalation rates that are applied to the base year costs. The selection of these cost escalation rates is dependent on subjective factors 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. In 2006, we lowered the cost escalation rate assumptions used in the ARO calculation by 0.85% due to projected reductions in both general and decommissioning specific inflation rates, resulting in a $201 million decrease in our nuclear decommissioning AROs.

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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. For regulated businesses 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.

We evaluate whether or not recovery of our regulatory assets through future 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 a regulatory asset is determined to be less than probable, it will be written off 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.

REVENUE RECOGNITION   UNBILLED REVENUE

We recognize and record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters which is performed on a systematic basis throughout the month. At the end of each month, the amounts of electric energy delivered to customers but not yet billed is estimated and recorded as unbilled revenue. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. Our customer receivables included $233 million and $263 million of accrued unbilled revenue at December 31, 2006 and 2005 respectively.

The calculation of unbilled revenues is complex and includes numerous estimates and assumptions including historical usage, applicable customer rates, weather factors and total daily electric generation supplied adjusted for line losses. Changes in generation patterns, customer usage patterns, meter accuracy and other factors which are the basis for the estimates of unbilled revenues could have a significant effect on the calculation and therefore on our results of operations and financial condition.

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. 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.

Through December 31, 2006, we have established liabilities for tax-related contingencies in accordance with Statement of Financial Accounting Standards (SFAS) No. 5, *Accounting for Contingencies*, and reviewed them in light of changing facts and circumstances. However, as discussed in Note 4 to our Consolidated Financial Statements, effective January 1, 2007, we adopted Financial Accounting Standards Board Interpretation

No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*. Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

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.

ACCOUNTING STANDARDS

During 2006 and 2005, we were required to adopt several new accounting standards, which are discussed in Note 3 to our Consolidated Financial Statements. See Note 4 to our Consolidated Financial Statements for a discussion of recently issued accounting standards that will be adopted in the future.

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions)	**2006**	**$ Change**	2005	$ Change	2004
Net Income	**$ 478**	**$ 468**	$ 10	$ (421)	$ 431

Overview

2006 VS. 2005

Net income increased to $478 million. Favorable drivers include the absence of $471 million of after-tax losses incurred in 2005 by the discontinued operations of VPEM and the absence of a 2005 charge resulting from the termination of a long-term power purchase agreement. Our results were also positively impacted by decreased consumption of fossil fuel due to milder weather and an increase in gains realized from the sale of emissions allowances. Unfavorable drivers include a decrease in regulated electric sales resulting from milder weather and other factors; a reduced benefit from financial transmission rights (FTRs) in excess of congestion costs and major storm damage and service restoration costs associated with tropical storm Ernesto in September 2006.

2005 VS. 2004

Net income decreased to $10 million. Unfavorable drivers include $471 million of after-tax losses incurred by the discontinued operations of VPEM and a charge resulting from the termination of a long-term power purchase agreement. Our results were also negatively affected by the impact of higher commodity prices on fuel and purchased power expenses.

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Analysis of Consolidated Operations

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

Year Ended December 31, (millions)	2006	$ Change	2005	$ Change	2004
Operating Revenue	$ 5,603	$ (109)	$ 5,712	$ 341	$ 5,371
Operating Expenses					
Electric fuel and energy purchases	2,384	(169)	2,553	802	1,751
Purchased electric capacity	453	(24)	477	(73)	550
Other energy-related commodity purchases	56	22	34	(4)	38
Other operations and maintenance	1,028	83	945	(294)	1,239
Depreciation and amortization	536	9	527	31	496
Other taxes	163	(7)	170	2	168
Other income	75	5	70	21	49
Interest and related charges	296	(26)	322	73	249
Income tax expense	284	15	269	(70)	339
Loss from discontinued operations, net of tax		471	(471)	(312)	(159)

An analysis of our results of operations for 2006 compared to 2005 and 2005 compared to 2004 follows:

2006 VS. 2005

Operating Revenue decreased 2% to $5.6 billion, reflecting the combined effects of:

- A $218 million decrease associated with milder weather. As compared to the prior year, we experienced a 9% decline in cooling degree days and a 16% decline in heating degree days; and
- A $53 million decrease in sales to wholesale customers primarily resulting from milder weather; partially offset by
- An $81 million increase due to new customer connections primarily in our residential and commercial customer classes;
- A $56 million increase attributable to rate variations resulting from changes in customer usage patterns and sales mix and other factors;
- An $18 million increase in ancillary service revenue from PJM;
- A $13 million increase due to the collection of a new Virginia sales and use tax surcharge from customers; and
- A $9 million increase primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions which was offset by a comparable increase in *Electric fuel and energy purchases expense.*

Operating Expenses and Other Items

Electric fuel and energy purchases expense decreased 7% to $2.4 billion, primarily due to lower commodity prices, including purchased power, and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by an increase in purchased power volumes.

Purchased electric capacity expense decreased 5% to $453 million, primarily due to scheduled capacity reductions for certain long-term power purchase contracts, as well as the termination of a long-term power purchase agreement in connection with the purchase of the related generating facility in February 2005.

Other energy-related commodity purchases expense increased 65% to $56 million, primarily reflecting an increase in nonutility coal purchased for resale.

Other operations and maintenance expense increased 9% to $1.0 billion, primarily reflecting:

- A $41 million increase due to a reduced benefit from FTRs granted by PJM used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
- A $29 million increase related to major storm damage and service restoration costs associated with our distribution operations, primarily resulting from tropical storm Ernesto in September 2006;
- A $15 million increase resulting from higher salaries, wages, and pension and medical benefits;

- A $12 million increase in outage costs primarily due to an increase in the number of scheduled outages at certain of our electric generating facilities;
- A $9 million increase due to the amortization of a regulatory asset associated with amounts subject to collection under a Virginia sales and use tax surcharge, net of credits resulting from additions to the regulatory asset during the period;
- A $7 million increase related to services provided by Dominion Resources Services, Inc.;
- A $7 million charge resulting from the write-off of certain assets no longer in use at one of our electric generating facilities; and
- A $4 million increase in PJM ancillary service charges; partially offset by
- A $20 million increase in gains from the sale of emissions allowances; and
- A net benefit from the absence of the following items recognized in 2005:
  - A $77 million charge resulting from the termination of a long-term power purchase agreement; partially offset by
  - A $25 million net benefit resulting from the establishment of certain regulatory assets in connection with the settlement of a North Carolina rate case.

Interest and related charges decreased 8% to $296 million, primarily reflecting the absence of prepayment penalties resulting from the early redemption of debt in 2005, partially offset by additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations reflects the absence of losses incurred by the discontinued operations of VPEM prior to its disposition in December 2005.

2005 VS. 2004

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

- A $153 million increase in sales to wholesale customers;
- A $99 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions which was more than offset by an increase in *Electric fuel and energy purchases expense*;
- A $77 million increase primarily due to the impact of comparably favorable weather on customer usage. As compared to the prior year, we experienced an 8% increase in cooling degree days and a 3% increase in heating degree days; and
- A $59 million increase associated with new customer connections primarily in our residential and commercial customer classes; partially offset by
- A $25 million decrease attributable to rate variations resulting from changes in customer usage patterns and sales mix and other factors; 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, 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;
- A $54 million gain resulting from the sale of emissions allowances; and
- A net benefit from the absence 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 certain 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.

Outlook

We believe our operating businesses will provide stable growth in net income in 2007. The following are growth factors that will impact these expected results:

- A decrease in unrecovered Virginia fuel expenses as a result of annual adjustments to our fuel factor beginning July 1, 2007;
- A potential increase in regulated electric sales, as compared to 2006, assuming our utility service territory experiences a return to normal weather in 2007; and
- Continued growth in utility customers.

The growth factors in 2007 are expected to be partially offset by:

- A decrease in gains from sales of emissions allowances;
- Increased salaries, wages and benefits expense; and
- Increased interest expense.

An important development impacting the future of our Company is the passage of legislation in Virginia that would re-regulate certain elements of our business, as discussed in *Status of Electric Restructuring in Virginia* under *Future Issues and Other Matters*. Since competitive markets have not developed in Virginia, we are supporting legislation passed by the Virginia General Assembly in early 2007 that would create a hybrid regulatory model designed to modify the traditional regulatory method to better suit it to the financial realities of undertaking major new generation and infrastructure projects. We believe this model would continue to provide our customers with comparatively low rates and ensure our ability to build new generation and other infrastructure needed to keep pace with growing demand for electricity in Virginia. The Governor has until March 26, 2007 to sign, propose amendments to, or veto the proposed legislation. With the Governor s signature, the legislation would become law effective July 1, 2007. At this time, we cannot predict the outcome of the legislation.

SEGMENT RESULTS OF OPERATIONS

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

Year Ended December 31, (millions)	**2006**	**$ Change**	2005	$ Change	2004
Delivery	**$ 270**	**$ (28)**	$ 298	$ 10	$ 288
Energy	**69**	**3**	66	(10)	76
Generation	**151**	**(24)**	175	(205)	380
Primary operating segments	**490**	**(49)**	539	(205)	744
Corporate	**(12)**	**517**	(529)	(216)	(313)
Consolidated	**$ 478**	**$ 468**	$ 10	$ (421)	$ 431

Delivery

Presented below are operating statistics related to our Delivery operations:

Year Ended December 31,	**2006**	**% Change**	2005	% Change	2004
Electricity delivered (million mwhrs)(1)	**79.8**	**(2)%**	81.4	4%	78.0
Degree days (electric service area):					
Cooling(2)	**1,557**	**(9)**	1,707	8	1,585
Heating(3)	**3,178**	**(16)**	3,784	3	3,682
Average electric delivery customer accounts(4)	**2,327**	**2**	2,286	2	2,244

mwhrs = megawatt hours

(1) Includes electricity delivered through the retail choice program for our Virginia jurisdictional electric customers.
(2) Cooling degree days (CDDs) are units measuring the extent to which the average daily temperature is greater than 65 degrees. CDDs are calculated as the difference between the average temperature for each day and 65 degrees.
(3) Heating degree days (HDDs) are units measuring the extent to which the average temperature is less than 65 degrees. HDDs are calculated as the difference between the average temperature and 65 degrees.
(4) Thirteen-month average, in thousands.

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

2006 VS. 2005

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	**$ (29)**
Customer growth	**11**
Other[1]	**15**
Major storm damage and service restoration	**(18)**
2005 North Carolina rate case settlement	**(6)**
Interest expense	**6**
Other	**(7)**
Change in net income contribution	**$ (28)**

(1) Attributable to rate variations from changes in customer usage patterns and sales mix and other factors.

2005 VS. 2004

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	$ 14
Customer growth	11
Change in segment revenue allocation[1]	(2)
2005 North Carolina rate case settlement	6
Interest expense	(11)
Depreciation and amortization	(8)
Salaries, wages and benefits expense	(6)
Other	6
Change in net income contribution	$ 10

(1) A change in the seasonal allocation of electric utility base rate revenue among the primary operating segments effective January 1, 2005.

Energy

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

2006 VS. 2005

(millions)	Increase (Decrease)
Interest expense	**$ 4**
RTO start-up and integration costs[1]	**3**

Regulated electric sales:		
Weather		**(5)**
Customer growth		**3**
Other		**(2)**
Change in net income contribution	**$**	**3**

(1) Reflects the absence of a charge incurred in 2005 for the write-off of certain previously deferred start-up and integration costs associated with joining an RTO.

2005 VS. 2004

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

Generation

Presented below are operating statistics related to our Generation operations:

Year Ended December 31,	**2006**	**% Change**	2005	% Change	2004
Electricity supplied (million mwhrs)	**79.7**	**(2)%**	81.4	4%	78.0
Degree days (electric service area):					
Cooling	**1,557**	**(9)**	1,707	8	1,585
Heating	**3,178**	**(16)**	3,784	3	3,682

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

	2006 Source	2005 Source	2004 Source
Nuclear(1)	**31%**	31%	32%
Coal(2)	**38**	37	38
Oil	**1**	4	6
Purchased power, net	**26**	22	19
Natural gas(3)	**4**	5	5
Other		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. The average cost of coal for 2006 Virginia in-system generation was $27.35 per mwhr.
(3) Includes natural gas used in combustion turbines that are fueled by gas.
(4) Excludes off-system sales.

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

2006 VS. 2005

(millions)		Increase (Decrease)
Regulated electric sales:		
Weather	$	(64)
Customer growth		24
Other[1]		17
Energy supply margin[2]		(27)
Salaries, wages and benefits expense		(10)
2005 North Carolina rate case settlement		(10)
Outage costs		(7)
Unrecovered Virginia fuel expenses		40
Sale of emissions allowances		12
Interest expense		6
Other		(5)
Change in net income contribution	$	(24)

(1) Primarily attributable to rate variations from changes in customer usage patterns and sales mix and other factors.
(2) Primarily reflects a reduced benefit from FTRs in excess of congestion costs.

2005 VS. 2004

(millions)		Increase (Decrease)
Unrecovered Virginia fuel expenses[1]	$	(280)
Interest expense		(24)
Salaries, wages and benefits expense		(17)
Depreciation expense		(12)
Energy supply margin[2]		40
Regulated electric sales:		
Weather		39
Customer growth		24
Change in segment revenue allocation		5
Capacity expenses		37
2005 North Carolina rate case settlement		10
Other		(27)
Change in net income contribution	$	(205)

(1) Reflects higher commodity prices including purchased power.
(2) The increase in energy supply margin reflects a benefit related to FTRs.

Corporate

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

Year Ended December 31,	**2006**	2005	2004

(millions)			
VPEM discontinued operations	**$**	$ (471)	$ (159)
Specific items attributable to operating segments	**(12)**	(58)	(155)
Other			1
Net expense	**$ (12)**	$ (529)	$ (313)

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our primary operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 25 to our Consolidated Financial Statements for a discussion of these items.

LIQUIDITY AND CAPITAL RESOURCES

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

At December 31, 2006, we had $1.0 billion of unused capacity under our joint credit facility. See discussion under *Joint Credit Facilities and Short-Term Debt*.

A summary of our cash flows for 2006, 2005 and 2004 is presented below:

Year Ended December 31,	**2006**	2005	2004
(millions)			
Cash and cash equivalents at beginning of year	**$ 54**	$ 2	$ 46
Cash flows provided by (used in):			
Operating activities	**1,080**	1,496	1,129
Investing activities	**(960)**	(800)	(835)
Financing activities	**(156)**	(644)	(338)
Net increase (decrease) in cash and cash equivalents	**(36)**	52	(44)
Cash and cash equivalents at end of year	**$ 18**	$ 54	$ 2

Operating Cash Flows

In 2006, net cash provided by operating activities decreased by $416 million as compared to 2005, primarily reflecting the absence of cash provided by VPEM prior to its disposition in December 2005. We believe that our operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and provide dividends to Dominion. However, our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in Item 1A. Risk Factors.

CREDIT RISK

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Presented below is a summary of our gross exposure as of December 31, 2006 for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. We held no collateral for these transactions at December 31, 2006.

(millions)	**Gross Credit Exposure**
Investment grade[1]	$ 3
Non-investment grade	
No external ratings:	

Internally rated investment grade[2]		48
Internally rated non-investment grade		
Total	$	51

(1) Designations as investment grade are based on minimum credit ratings assigned by Moody s Investors Service (Moody s) and Standard & Poor s Ratings Services (Standard & Poor s). The five largest counterparty exposures, combined, for this category represented approximately 6% of the total gross credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented approximately 94% of the total gross credit exposure.

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Investing Cash Flows

Significant investing activities in 2006 included:

- $925 million for environmental upgrades, routine capital improvements of generation facilities and construction and improvements of electric transmission and distribution assets;
- $550 million for purchases of securities held as investments in our nuclear decommissioning trusts; and
- $122 million for nuclear fuel expenditures; partially offset by
- $533 million of proceeds from sales of securities held as investments in our nuclear decommissioning trusts; and
- $75 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*, our ability to borrow funds or issue securities and the return demanded by investors are affected by our credit ratings. In 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.

Significant financing activities in 2006 included:

- $624 million for the repayment of long-term debt;
- $349 million of common dividend payments; and
- $287 million for the net repayment of short-term debt; partially offset by
- $1 billion from the issuance of long-term debt; and
- $129 million from the net issuance of affiliated current borrowings.

JOINT CREDIT FACILITIES AND SHORT-TERM DEBT

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. Short-term financing is supported by a $3.0 billion five-year joint revolving credit facility dated February 2006 with Dominion and Consolidated Natural Gas Company (CNG), a wholly-owned subsidiary of Dominion, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion, CNG and us and other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2006, total commercial paper outstanding supported by the joint credit facility was $1.76 billion and the total amount of letter of credit issuances was $236 million, leaving approximately $1.0 billion available for issuance.

LONG-TERM DEBT

During 2006, we issued the following long-term debt:

Type	**Principal** (millions)	**Rate**	**Maturity**
Senior notes	$ 550	6.00%	2036

Senior notes	450	5.40%	2016
Total long-term debt issued	$ 1,000		

During 2006, we repaid $624 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. Our nonregulated subsidiaries had outstanding Dominion money pool borrowings totaling $140 million and $12 million at December 31, 2006 and 2005, respectively. At December 31, 2006 and 2005, our borrowings under a long-term note totaled $220 million. We incurred interest charges related to our borrowings of $10 million and $9 million at December 31, 2006 and 2005, 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, event risk if applicable, and the credit ratings of our parent company, Dominion.

Our credit ratings as of February 1, 2007 follow:

	Fitch	Moody s	Standard & Poor s
Mortgage bonds	A	A3	A-
Senior unsecured (including tax-exempt) debt securities	BBB+	Baa1	BBB
Junior subordinated debt securities	BBB	Baa2	BB+
Preferred stock	BBB	Baa3	BB+
Commercial paper	F2	P-2	A-2

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As of February 1, 2007, Fitch Ratings Ltd. (Fitch) and Moody s maintain a stable outlook, and Standard & Poor s maintains a positive outlook for their ratings of our 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:

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

We are required to pay minimal annual commitment fees to maintain the joint 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 a maximum debt to total capital ratio and cross-default provisions.

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, 2006, our calculated debt to total capital ratio was 47%. 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 $35 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.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2006, there were no events of default under our covenants.

Dividend Restrictions

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2006, 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 at December 31, 2006.

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

Cash Flows from Discontinued Operations

The impact of VPEM s operations on our Consolidated Statements of Cash Flows is presented below. The transfer of VPEM to Dominion has not had a negative impact on our liquidity.

Year Ended December 31, (millions)	2005	2004
Operating cash flows	$ 365	$ (289)
Investing cash flows	106	(110)
Financing cash flows	(468)	392

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, 2006. 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 in 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 2007.

(millions)	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Long-term debt[(1)]	$ 1,267	$ 418	$ 270	$ 2,927	$ 4,882
Interest payments[(2)]	245	368	323	2,406	3,342
Leases	28	44	29	27	128
Purchase obligations[(3)]:					
Purchased electric capacity for utility operations	414	745	697	2,207	4,063
Fuel to be used for utility operations	717	838	367	573	2,495
Transportation and storage	11	26	12	9	58
Other	55	24	1		80
Other long-term liabilities[(4)]	4	4			8
Total cash payments	$ 2,741	$ 2,467	$ 1,699	$ 8,149	$ 15,056

(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 payments related to our trust preferred securities.
(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, AROs and employee benefit plan contributions that are not contractually fixed as to timing and amount. See Notes 12, 13 and 20 to our Consolidated Financial Statements. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year.

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PLANNED CAPITAL EXPENDITURES

Our planned capital expenditures are expected to total approximately $1.2 billion annually in both 2007 and 2008. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Our annual capital expenditures for plant and equipment for 2007, including environmental upgrades and construction improvements, are expected to total approximately as follows:

- Generation and nuclear fuel: $654 million;
- Transmission: $168 million; and
- Distribution: $390 million.

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation in the future. We currently have plans to restart our Hopewell plant in 2007, a 63-megawatt (Mw) (at net summer capability) coal burning plant located in Hopewell, Virginia which has been out of service since 2002, and we are evaluating a 290-Mw (at net summer capability) expansion of our Ladysmith site in Ladysmith, Virginia. We are also leading a consortium of companies that are considering building a 500 to 600-Mw coal-fired plant in southwest Virginia. We will continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future. Through 2009, we will continue to meet any additional capacity requirements through market purchases.

FUTURE ISSUES AND OTHER MATTERS

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

The Virginia Electric Utility Restructuring Act was enacted in 1999 (1999 Virginia Restructuring Act) and established a plan to restructure the electric utility industry in Virginia. In general, this legislation provided for a transition from bundled cost-based rates for regulated electric service to unbundled cost-based rates for transmission and distribution services and to market pricing for generation services, including retail choice for customers. The 1999 Virginia Restructuring Act addressed capped base rates, RTO participation, retail choice, stranded costs recovery and functional separation of an electric utility s generation from its transmission and distribution operations.

Retail choice was made available to all of our Virginia regulated electric customers since January 1, 2003. We have separated our generation, distribution and transmission functions through the creation of divisions. State regulatory requirements ensure that our generation division and other divisions operate independently and prevent cross-subsidies between our generation division and other divisions. Additionally, in 2005, we became a member of PJM, an RTO, and have integrated our electric transmission facilities into the PJM wholesale electricity markets. Under the 1999 Virginia Restructuring Act, our base rates have been capped until December 31, 2010, unless modified earlier.

2004 amendments to the 1999 Virginia Restructuring Act addressed a minimum stay exemption program, a wires charge exemption program and the development of a coal-fired generating plant in southwest Virginia.

VIRGINIA FUEL EXPENSES

In May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

- Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);
- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months; and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, 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. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

STRANDED COSTS

Stranded costs are 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. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. 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 risks 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 1999 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.

2007 VIRGINIA RESTRUCTURING ACT AMENDMENTS

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

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sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern United States (U.S.), with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the Consumer Price Index in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the Consumer Price Index;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiv ing an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Govenor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Govenor s signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

Transmission Expansion Plan

Each year, as part of PJM s Regional Transmission Expansion Plan (RTEP) process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to Virginia, of which we will construct approximately 70 miles in Virginia and a subsidiary of Allegheny Energy, Inc. will construct the remainder. The second project is an approximately 56-mile 500-kV transmission line that we will construct in southeastern Virginia. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission, during the period ending December 31, 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. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments.

ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

We incurred approximately $102 million, $134 million and $115 million of expenses (including depreciation) during 2006, 2005 and 2004, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $133 million and $134 million in 2007 and 2008. In addition, capital expenditures related to environmental controls were $170 million, $42 million and $84 million for 2006, 2005 and 2004, respectively. These expenditures are expected to be approximately $197 million and $142 million for 2007 and 2008.

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CLEAN AIR ACT COMPLIANCE

In March 2005, the Environmental Protection Agency (EPA) Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in 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 imposed 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. Several of these states have issued proposed regulations for the implementation of CAIR and CAMR, but only West Virginia has adopted final rules. In April 2006, legislation titled, *Air Emissions Control*, which addresses many of the requirements of CAIR and CAMR was adopted in Virginia and is more strict than the federal requirements. This legislation, however, does not serve as Virginia s final plan for the implementation of CAIR and CAMR. These regulatory and legislative actions will require additional reductions in emissions from our fossil fuel-fired generating facilities and are already addressed in our current compliance planning. In June 2005, the EPA finalized amendments to the Regional Haze Rule, also known as the Clean Air Visibility Rule (CAVR). States have not yet finalized regulations to implement CAVR. Although we anticipate that the emission reductions achieved through compliance with CAIR and CAMR will address CAVR, at this time we cannot predict with certainty any additional financial impacts of the regional haze regulations on our operations. 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 emission 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 $451 million during the period 2007 through 2011.

In March 2004, the State of North Carolina filed a petition with the EPA under Section 126 of the CAA seeking additional NO_x and SO_2 reductions from electrical generating units in thir

teen states, claiming emissions from those units are contributing to air quality problems in North Carolina. We have electrical generating units in two of the thirteen states. In March 2006, the EPA issued a final rulemaking through which it denied the North Carolina petition on the basis that the implementation of the CAIR adequately addresses the air quality issues identified by North Carolina. Therefore, we do not anticipate additional expenditures in relation to this matter.

CLEAN WATER ACT COMPLIANCE

In July 2004, the EPA published regulations that govern existing utilities that employ a cooling water intake structure, and that have flow levels exceeding a minimum threshold. The EPA s rule presents several compliance options. We have been evaluating information from certain of our existing power stations and had expected to spend approximately $4 million over the next two years conducting studies and technical evaluations. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. We cannot predict the outcome of the EPA regulatory process or determine with any certainty what specific controls may be required.

FUTURE ENVIRONMENTAL REGULATIONS

From time to time, the U.S. Congress considers 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 periods of up to ten to fifteen years. If these new proposals are adopted, additional significant expenditures may be required.

In 1997, the U.S. signed an International Protocol (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. 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% during the period 2002 through 2012. We expect continuing legislative efforts in the U.S. Congress seeking to target the reductions of greenhouse gas emissions. The cost of compliance with the Protocol or other greenhouse gas reduction programs 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.

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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, foreign currency exchange rates, interest 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. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to equity price risk through various portfolios of equity securities.

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

Commodity Price Risk

To manage price risk, we primarily hold commodity-based financial derivative instruments for nontrading purposes associated with the purchase of electricity and natural gas. The derivatives used to manage our commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps 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 $3 million in the fair value of our non-trading commodity-based financial derivatives as of December 31, 2006. 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. For example, our expenses for power purchases when combined with the settlement of commodity derivative instruments used for

hedging purposes, will generally result in a range of prices for those purchases contemplated by the risk management strategy.

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 is minimal. A hypothetical 10% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately $3 million and $6 million in the fair value of currency forward contracts held by us at December 31, 2006 and 2005, respectively.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2006 and 2005, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $6 million, respectively.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $36 million and $32 million in 2006 and 2005, respectively. We recorded, in AOCI, gross unrealized gains on these investments of $86 million in 2006 and net unrealized gains of $10 million in 2005.

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 provide to Dominion, representing our share of employee benefit plan contributions.

Risk Management Policies

We have established operating procedures with corporate management to 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 the Company. 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, 2006 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 2006 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.

February 28, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of

Virginia Electric and Power Company

Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries (the Company) as of December 31, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 method of accounting to adopt a new accounting standard for conditional asset retirement obligations in 2005.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 28, 2007

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CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (millions)	**2006**	2005	2004
Operating Revenue	**$ 5,603**	$ 5,712	$ 5,371
Operating Expenses			
Electric fuel and energy purchases	**2,384**	2,553	1,751
Purchased electric capacity	**453**	477	550
Other energy-related commodity purchases	**56**	34	38
Other operations and maintenance:			
External suppliers	**717**	653	975
Affiliated suppliers	**311**	292	264
Depreciation and amortization	**536**	527	496
Other taxes	**163**	170	168
Total operating expenses	**4,620**	4,706	4,242
Income from operations	**983**	1,006	1,129
Other income	**75**	70	49
Interest and related charges:			
Interest expense	**266**	292	218
Interest expense junior subordinated notes payable to affiliated trust	**30**	30	31
Total interest and related charges	**296**	322	249
Income from continuing operations before income tax expense	**762**	754	929
Income tax expense	**284**	269	339
Income from continuing operations before cumulative effect of change in accounting principle	**478**	485	590
Loss from discontinued operations (net of income tax benefit of $274 in 2005 and $99 in 2004)		(471)	(159)
Cumulative effect of change in accounting principle (net of income tax benefit of $3)		(4)	
Net Income	**478**	10	431
Preferred dividends	**16**	16	16
Balance available for common stock	**$ 462**	$ (6)	$ 415

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

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CONSOLIDATED BALANCE SHEETS

At December 31, (millions)	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 18	$ 54
Customer receivables (less allowance for doubtful accounts of $7 at both dates)	650	700
Affiliated receivables	18	7
Other receivables (less allowance for doubtful accounts of $9 at both dates)	80	60
Inventories (average cost method):		
Materials and supplies	231	207
Fossil fuel	274	236
Deferred income taxes	37	32
Prepayments	133	36
Other	14	34
Total current assets	1,455	1,366
Investments		
Nuclear decommissioning trust funds	1,293	1,166
Other	22	22
Total investments	1,315	1,188
Property, Plant and Equipment		
Property, plant and equipment	20,771	20,317
Accumulated depreciation and amortization	(8,353)	(8,055)
Total property, plant and equipment, net	12,418	12,262
Deferred Charges and Other Assets		
Intangible assets	195	160
Regulatory assets	241	326
Other	59	147
Total deferred charges and other assets	495	633
Total assets	$ 15,683	$ 15,449

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At December 31, (millions)	2006	2005
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 1,267**	$ 618
Short-term debt	**618**	905
Accounts payable	**418**	415
Payables to affiliates	**62**	42
Affiliated current borrowings	**140**	12
Accrued interest, payroll and taxes	**227**	288
Other	**209**	212
Total current liabilities	**2,941**	2,492
Long-Term Debt		
Long-term debt	**2,987**	3,256
Junior subordinated notes payable to affiliated trust	**412**	412
Notes payable other affiliates	**220**	220
Total long-term debt	**3,619**	3,888
Deferred Credits and Other Liabilities		
Deferred income taxes	**2,274**	2,201
Deferred investment tax credits	**34**	49
Asset retirement obligations	**641**	834
Regulatory liabilities	**430**	409
Other	**95**	86
Total deferred credits and other liabilities	**3,474**	3,579
Total liabilities	**10,034**	9,959
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	**887**	886
Retained earnings	**955**	842
Accumulated other comprehensive income	**162**	117
Total common shareholder s equity	**5,392**	5,233
Total liabilities and shareholder s equity	**$ 15,683**	$ 15,449

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

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER S EQUITY AND COMPREHENSIVE INCOME

	Common Stock		Other		Accumulated Other	
(millions, except for shares)	Shares (thousands)	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income	Total
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
Net 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)
Net unrealized gains on nuclear decommissioning trust funds, net of $8 tax expense					13	13
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $4 tax expense					(7)	(7)
Net derivative gains hedging activities, net of $7 tax expense					(10)	(10)
Total comprehensive income				10	(12)	(2)
Equity contribution by parent			833			833
Tax benefit from stock awards and stock options exercised			3			3
Dividends				(470)		(470)
Balance at December 31, 2005	198	3,388	886	842	117	5,233
Comprehensive income:						
Net income				**478**		**478**
Net deferred derivative losses hedging activities, net of $6 tax benefit					**(10)**	**(10)**

Unrealized gains on nuclear decommissioning trust funds, net of $40 tax expense					62	62
Amounts reclassified to net income:						
Realized gains on nuclear decommissioning trust funds, net of $7 tax expense					(9)	(9)
Net derivative losses hedging activities, net of $2 tax benefit					2	2
Total comprehensive income				478	45	523
Tax benefit from stock awards and stock options exercised			1			1
Dividends				(365)		(365)
Balance at December 31, 2006	198	$ 3,388	$ 887	$ 955	$ 162	$ 5,392

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)	2006	2005	2004
Operating Activities			
Net income	$ 478	$ 10	$ 431
Adjustments to reconcile net income to net cash from operating activities:			
Net realized and unrealized derivative (gains)/losses	(2)	1,041	(25)
Depreciation and amortization	619	604	578
Deferred income taxes and investment tax credits, net	24	(267)	125
Deferred fuel expenses, net	99	76	86
Gain on sale of emissions allowances	(74)	(54)	(35)
Other adjustments to net income	(27)	9	(16)
Changes in:			
Accounts receivable	30	(149)	(135)
Affiliated accounts receivable and payable	6	(40)	
Inventories	(62)	(18)	(64)
Pension assets	35	56	40
Accounts payable	1	253	(51)
Accrued interest, payroll and taxes	(61)	164	(15)
Margin deposit assets and liabilities	11	(69)	4
Other operating assets and liabilities	3	(120)	206
Net cash provided by operating activities	1,080	1,496	1,129
Investing Activities			
Plant construction and other property additions	(925)	(741)	(761)
Purchases of nuclear fuel	(122)	(111)	(96)
Purchases of securities	(550)	(311)	(277)
Proceeds from sales of securities	533	257	237
Proceeds from sale of emissions allowances	75	56	41
Other	29	50	21
Net cash used in investing activities	(960)	(800)	(835)
Financing Activities			
Issuance (repayment) of short-term debt, net	(287)	638	(450)
Issuance (repayment) of affiliated current borrowings, net	129	(256)	491
Issuance of long-term debt	1,000		
Repayment of long-term debt	(624)	(532)	(344)
Issuance of common stock			500
Common dividend payments	(349)	(454)	(518)
Preferred dividend payments	(16)	(16)	(16)
Other	(9)	(24)	(1)
Net cash used in financing activities	(156)	(644)	(338)
Increase (decrease) in cash and cash equivalents	(36)	52	(44)
Cash and cash equivalents at beginning of year	54	2	46
Cash and cash equivalents at end of year	$ 18	$ 54	$ 2
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 254	$ 307	$ 260
Income taxes	419	156	46
Noncash investing and 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
		200	11

Conversion of short-term borrowings and other amounts payable to parent to other paid-in capital	
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 for sale 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. In 2005, we became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and integrated our electric transmission facilities into the PJM wholesale electricity 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 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. In addition, the discontinued operations of VPEM are included in our Corporate segment results.

We manage our daily operations through three primary operating segments: Delivery, Energy and Generation. 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. Our assets remain wholly owned by us and our legal subsidiaries.

The terms Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia 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, including our Virginia and North Carolina operations and our consolidated subsidiaries.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

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

Our 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 2005 and 2004 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2006 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 receivables at December 31, 2006 and 2005 included $233 million and $263 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 related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

Effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were locked in until July 1, 2007. Effective July 1, 2007, the fuel factor will be adjusted as discussed under *Virginia Fuel Expenses* in Note 21. Approximately 7.5% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as a regulatory asset, which is expected to be recovered by July 1, 2007.

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 taxable income or loss, determined on a separate company basis. However, prior to the repeal, effective in 2006, of the Public Utility Holding Company Act of 1935 (the 1935 Act), 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, 2006, our Consolidated Balance Sheet included $105 million of prepaid federal income taxes (recorded in prepayments), $10 million of federal income taxes receivable from Dominion (recorded in deferred charges and other assets) and $26 million of state income taxes payable to Dominion (recorded in accrued interest, payroll and taxes). At December 31, 2005, our Consolidated Balance Sheet included $10 million of prepaid state income taxes (recorded in prepayments), $55 million of prepaid federal income taxes (recorded in deferred charges and other assets), $113 million of federal income taxes payable to Dominion (recorded in accrued interest, payroll and taxes) and $11 million of federal income taxes payable to Dominion (recorded in deferred credits and other liabilities).

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2006 and 2005, accounts payable included $33 million and $39 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

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

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

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:** All unrealized changes in fair value and settlements for physical derivative sales contracts are presented in revenues, while all unrealized changes in fair value and settlements for physical derivative purchase contracts are presented in expenses.

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 either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, we formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. We assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, we 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 cease to be highly effective hedges.

Cash Flow Hedges A portion of our hedge strategies represent cash flow hedges of the variable price risk associated with the purchase of natural gas and electricity. We also 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.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

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 trusts as available-for-sale securities. Available-for-sale securities are reported at fair value with realized gains and losses and any other- than-temporary declines in fair value included in other income 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. Prior to 2006, we used several criteria to evaluate other-than-temporary declines, including the length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its cost and the expected

fair value of the security. If a decline in fair value was determined to be other than temporary, the security was written down to its fair value at the end of the reporting period.

In 2006, we changed our method of assessing other-than-temporary declines such that the intent and ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value must be demonstrated prior to the consideration of the other criteria mentioned above. Since regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments, we do not have the ability to hold individual securities in the trusts. Accordingly, we consider all securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, 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 it is incurred. In 2006, 2005 and 2004, we capitalized interest costs of $10 million, $6 million and $7 million, respectively. In 2006, 2005 and 2004, for electric distribution and electric transmission property subject to cost-of-service utility rate regulation, we capitalized an allowance for funds used during construction of $11 million, $2 million and $2 million, respectively.

For electric distribution and electric 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 net book value at the retirement date.

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

(percent)	**2006**	2005	2004
Generation	**2.07**	2.04	1.97
Transmission	**1.97**	1.97	1.97
Distribution	**3.45**	3.46	3.46
General and other	**4.93**	5.43	5.76

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. We report the amortization of nuclear fuel in electric fuel and energy purchases expense in our Consolidated Statements of Income and in depreciation and amortization in our Consolidated Statements of Cash Flows.

Emissions Allowances

Emissions allowances are issued by the 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 in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances. Allowances issued directly to us by the EPA are carried at zero cost.

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

Impairment of Long-Lived and Intangible Assets

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

Regulatory Assets and Liabilities

For utility operations subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates 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 future retirement activities. 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 in our Consolidated Statements of Income.

Amortization of Debt Issuance Costs

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

NOTE 3. NEWLY ADOPTED ACCOUNTING STANDARDS

2006

SAB 108

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB 108 provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year s financial statements are materially misstated. Our adoption of SAB 108 on December 31, 2006 had no impact on our Consolidated Financial Statements.

2005

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 and 2004 as if we had applied the provisions of FIN 47 as of January 1, 2004:

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

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

NOTE 4. RECENTLY ISSUED ACCOUNTING STANDARDS

FIN 48

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Taking into consideration the uncertainty and judgement involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in the financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Beginning in 2007, FIN 48 requires disclosures about positions taken by an entity in its tax returns that are not recognized in its financial statements, descriptions of open tax years by major jurisdiction and reasonably possible significant changes in the amount of unrecognized tax benefits that could occur in the next twelve months.

With the adoption of FIN 48, we estimate that the cumulative effect of the change in accounting principle will not have a material impact on the beginning balance of our retained earnings as of January 1, 2007.

SFAS NO. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under 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,* and SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments.* We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS NO. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. The provisions of SFAS No. 159 will become effective for us beginning January 1, 2008. Early adoption is permitted provided that an election is also made to apply the provisions of SFAS No. 157. We are currently evaluating the impact that SFAS No. 159 may have on our results of operations and financial condition.

NOTE 5. OPERATING REVENUE

Our operating revenue consists of the following:

Year Ended December 31, (millions)	**2006**	2005	2004
Regulated electric sales	**$ 5,451**	$ 5,543	$ 5,180
Other	**152**	169	191
Total operating revenue	**$ 5,603**	$ 5,712	$ 5,371

NOTE 6. INCOME TAXES

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

Year Ended December 31, (millions)	2006	2005	2004
Current expense:			
Federal	$ 213	$ 157	$ 184
State	47	40	53
Total current	260	197	237
Deferred expense:			
Federal	29	88	121
State	10	(1)	(3)
Total deferred	39	87	118
Amortization of deferred investment tax credits	(15)	(15)	(16)
Total income tax expense	$ 284	$ 269	$ 339

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

Year Ended December 31,	2006	2005	2004
U.S statutory rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
State income tax, net of federal tax benefit	4.8	3.4	3.5
Amortization of investment tax credits	(1.5)	(1.6)	(1.3)
Employee benefits	(0.2)	(0.6)	(0.5)
Other, net	(0.8)	(0.5)	(0.2)
Effective tax rate	37.3%	35.7%	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)	2006	2005
Deferred income taxes:		
Total deferred income tax assets	$ 161	$ 148
Total deferred income tax liabilities	2,398	2,318
Total net deferred income tax liabilities	$ 2,237	$ 2,170
Total deferred income taxes:		
Depreciation method and plant basis differences	$ 2,072	$ 1,979
Deferred state income taxes	187	174
Unrealized gains on available-for-sale securities	81	53
Loss and credit carryforwards	(63)	(53)
Other	(40)	17
Total net deferred income tax liabilities	$ 2,237	$ 2,170

At December 31, 2006, we had federal and state minimum tax credits of $58 million that do not expire and other federal and state income tax credits of $2 million that will expire if unutilized by 2025.

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We are routinely audited by federal and state tax authorities. We establish liabilities for tax-related contingencies and review them in light of changing facts and circumstances. Although the results of these audits are uncertain, we believe that the ultimate outcome will not have a material adverse effect on our financial position. At December 31, 2006 and 2005, our Consolidated Balance Sheets included no material income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Act)

The 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 Act. The 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 2006 is minimal.

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 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 year ended December 31, 2006, there were no gains or losses on hedging instruments that were determined to be ineffective. For the year ended December 31, 2005, we recognized in net income $11 million of gains as hedge ineffectiveness and $4 million of gains 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 2005 activity was related to the discontinued operations of VPEM.

The following table presents selected information related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2006:

(millions)	AOCI After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Natural gas	$ (2)	$ (2)	3 months
Electricity	(2)	(2)	3 months
Interest rate	1		106 months
Foreign currency	15	7	9 months
Total	$ 12	$ 3	

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

NOTE 8. 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 indirect wholly-owned subsidiaries. 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 in 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 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, on a net basis. For 2005 and 2004, our discontinued operations included operating revenue of $807 million and $373 million, respectively, and a loss before income taxes of $746 million and $259 million, respectively. VPEM s 2005 and 2004 results included the following affiliated transactions:

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

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, 2006 and 2005, are summarized below:

(millions)	**Fair Value**	**Total Unrealized Gains included in AOCI**	**Total Unrealized Losses included in AOCI (1)**
2006			
Equity securities	**$ 833**	**$ 239**	**$**
Debt securities	**425**	**7**	
Cash and other	**35**		
Total	**$ 1,293**	**$ 246**	**$**
2005			
Equity securities	$ 740	$ 168	$ 9
Debt securities	399	5	4
Cash and other	27		
Total	$ 1,166	$ 173	$ 13

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2006 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	$ 9
Due after one year through five years	123
Due after five years through ten years	125
Due after ten years	168
Total	$ 425

Gross realized gains on the sale of available-for-sale securities totaled $49 million, $19 million and $27 million in 2006, 2005 and 2004, respectively, and gross realized losses totaled $33 million, $8 million and $24 million in 2006, 2005 and 2004, 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, (millions)	**2006**	2005
Utility:		
Generation	**$ 10,088**	$ 10,243
Transmission	**1,777**	1,671
Distribution	**6,613**	6,338
Nuclear fuel	**907**	870
General and other	**592**	551
Plant under construction	**787**	637
Total utility	**20,764**	20,310
Nonutility other	**7**	7
Total property, plant and equipment	**$ 20,771**	$ 20,317

Jointly-Owned Utility Plants

Our proportionate share of jointly-owned utility plants at December 31, 2006 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	$ 1,017	$ 1,998	$ 553
Accumulated depreciation	(406)	(964)	(132)

Nuclear fuel		399	
Accumulated amortization of nuclear fuel		(331)	
Plant under construction	10	63	4

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 $37 million, $38 million and $27 million for 2006, 2005 and 2004, respectively. In 2006, we acquired $58 million of emissions allowances with an estimated weighted-average amortization period of 3.8 years. The components of our intangible assets are as follows:

At December 31,		**2006**		2005
(millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Software and software licenses	**$ 259**	**$ 165**	$ 250	$ 138
Emissions allowances	**63**	**4**	7	1
Other	**52**	**10**	55	13
Total	**$ 374**	**$ 179**	$ 312	$ 152

Annual amortization expense for intangible assets is estimated to be $48 million for 2007, $30 million for 2008, $23 million for 2009, $28 million for 2010 and $12 million for 2011.

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NOTE 12. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

December 31, (millions)	**2006**	2005
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	**$ 72**	$ 171
RTO start-up costs and administration fees (2)	**66**	39
Income taxes recoverable through future rates(3)	**46**	46
Termination of certain power purchase agreements(4)	**22**	24
Cost of decommissioning DOE uranium enrichment facilities(5)	**7**	16
Other	**28**	30
Total regulatory assets	**$ 241**	$ 326
Regulatory liabilities:		
Provision for future cost of removal(6)	**$ 409**	$ 388
Other	**21**	21
Total regulatory liabilities	**$ 430**	$ 409

(1) 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 $56 million at December 31, 2006.
(2) 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 $58 million in start-up costs and administration fees and $8 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.
(3) Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.
(4) 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.
(5) 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 June 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.
(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, 2006, approximately $143 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. We also have AROs related to certain electric transmission and distribution assets located on property that we do not own and hydroelectric generation facilities. We currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets. Thus, AROs for these assets will not be reflected in our Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. Generally, this will occur

when the expected retirement or abandonment dates are determined by our operational planning. The changes to our AROs during 2006 were as follows:

Amount

(millions)	
Asset retirement obligations at December 31, 2005	$ 834
Accretion	**40**
Revisions in estimated cash flows[1]	**(233)**
Asset retirement obligations at December 31, 2006	**$ 641**

(1) Primarily reflects a reduction in cost escalation rate assumptions that were applied to updated decommissioning cost studies, which reflected increases in base year costs, received for each of our nuclear facilities during the third quarter of 2006.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2006 and 2005, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.3 billion and $1.2 billion, respectively.

NOTE 14. VARIABLE INTEREST ENTITIES

FASB Interpretation No. 46 (revised December 2003), *Consolidation of 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 them to be considered potential variable interests in the counterparties. Two 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.

As of December 31, 2006, no further information has been received from the two remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these two potential VIE supplier entities of $1.3 billion at December 31, 2006. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $98 million, $106 million and $111 million for electric generation capacity and $75 million, $102 million and $59 million for electric energy from these entities for the years ended December 31, 2006, 2005 and 2004, respectively.

In February 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

and 2017. Total debt held by the entities is approximately $299 million. We have remaining purchase commitments with these two VIE supplier entities of $1 billion at December 31, 2006. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid $116 million, $116 million and $114 million for electric generation capacity and $55 million, $57 million and $47 million for electric energy from these entities for the years ended December 31, 2006, 2005 and 2004, respectively.

During 2005, we entered into four long-term contracts with unrelated limited liability companies (LLCs) to purchase synthetic fuel produced from coal. Certain variable pricing terms in the contracts protect the equity holders from variability in the cost of their coal purchases, and therefore, the LLCs were determined to be VIEs. After completing our FIN 46R analysis, we concluded that although our interests in the contracts, as a result of their pricing terms, represent variable interests in the LLCs, we are not the primary beneficiary. We paid $341 million and $205 million to the LLCs for coal and synthetic fuel produced from coal for the years ended December 31, 2006 and 2005, respectively. We are not subject to any risk of loss from the contractual arrangements, as our only obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts.

Our Consolidated Balance Sheets as of December 31, 2006 and 2005 reflect net property, plant and equipment of $337 million and $348 million, respectively and $370 million of debt, related to the consolidation, in accordance with FIN 46R, of a variable interest lessor entity through which we have financed and leased a power generation project. The debt is non-recourse to us and is secured by the entity s property, plant and equipment. The lease under which we operate the power generation facility terminates in August 2007. We intend to take legal title to the facility through repayment of the lessor s related debt at the end of the lease term.

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. Short-term financing is supported by a $3.0 billion five-year joint revolving credit facility dated February 2006 with Dominion and Consolidated Natural Gas Company (CNG), a wholly-owned subsidiary of Dominion, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion, CNG and us and other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

At December 31, 2006, total outstanding commercial paper supported by the joint credit facility was $1.76 billion, of which our borrowings were $618 million, with a weighted average interest rate of 5.41%. At December 31, 2005, total outstanding commercial paper supported by the previous joint credit facility was $1.4 billion, of which our borrowings were $905 million, with a weighted average interest rate of 4.46%.

At December 31, 2006, total outstanding letters of credit supported by the joint credit facility was $236 million, of which less than $1 million were issued on our behalf. At December 31, 2005, total outstanding letters of credit supported by the previous joint credit facility was $892 million, of which less than $1 million were issued on our behalf.

At December 31, 2006, capacity available under the joint credit facility was $1.0 billion.

NOTE 16. LONG-TERM DEBT

At December 31, (millions, except percentages)	**2006 Weighted Average Coupon(1)**	**2006**	2005
Long-Term Debt			

Secured First and Refunding Mortgage Bonds, 7.625%, due 2007 (2):		**$ 215**	$ 215
Secured Bank Debt:			
Variable rate, due 2007(3)	**5.85%**	**370**	370
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.75%, due 2006 to 2010	**5.22%**	**1,000**	1,600
4.75% to 8.625%, due 2013 to 2036	**5.62%**	**1,748**	762
Unsecured Callable and Puttable Enhanced SecuritiesSM, 4.10% due 2038(4)		**225**	225
Tax-Exempt Financings(5):			
Variable rate, due 2008	**3.69%**	**60**	60
Variable rates, due 2015 to 2027	**3.63%**	**137**	137
4.95% to 7.65%, due 2007 to 2010	**5.50%**	**232**	237
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 Dominion, 2.125%, due 2023		**220**	220
		4,882	4,501
Fair value hedge valuation(6)		**(8)**	(8)
Amount due within one year	**5.92%**	**(1,267)**	(618)
Unamortized discount and premium, net		**12**	13
Total long-term debt		**$ 3,619**	$ 3,888

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2006.
(2) Substantially all of our property is subject to the lien of the mortgage, securing our mortgage bonds.
(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, which totaled $337 million and $348 million at December 31, 2006 and 2005, respectively.
(4) On December 15, 2008, the securities are subject to redemption at par plus accrued interest, unless holders of related options exercise rights to purchase and remarket the notes.
(5) These financings relate to certain pollution control equipment at our generating facilities. The variable rate tax-exempt financings are supported by a stand-alone $3 billion five-year credit facility that terminates in February 2011. In February 2007, we exercised our call option and redeemed $62 million of our tax-exempt financings with a weighted average rate of 7.52%, with proceeds raised through the issuance of commercial paper.
(6) Represents the valuation of certain fair value hedges associated with our fixed- rate debt.

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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, 2006 were as follows:

(millions)	2007	2008	2009	2010	2011	Thereafter	Total
	$1,267	$ 290	$ 128	$ 250	$ 20	$ 2,927	$ 4,882

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2006, 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. 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 or if redeemed prior to maturity.

Distribution payments on the trust preferred securities are considered to be fully and unconditionally guaranteed by the Company 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, 2006 and 2005. 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 Vir-

ginia 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, 2006:

Dividend	Issued and Outstanding Shares (thousands)	Entitled Per Share Upon Liquidation
$5.00	107	$ 112.50

4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.47(1)
6.98	600	102.45(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1) Through 7/31/2007; $102.12 commencing 8/1/2007; amounts decline in steps thereafter to $100.00 by 8/1/2013.
(2) Through 8/31/2007; $102.10 commencing 9/1/2007; 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)	**2006**	2005
Net unrealized gains on derivatives hedging activities, net of tax	**$ 12**	$ 20
Net unrealized gains on nuclear decommissioning trust funds, net of tax	**150**	97
Total accumulated other comprehensive income	**$ 162**	$ 117

NOTE 19. DIVIDEND RESTRICTIONS

The Virginia Commission may prohibit any public service company from declaring or paying a dividend to an affiliate, if found to be detrimental to the public interest. At December 31, 2006, the Virginia Commission had not restricted our payment of dividends.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, CONTINUED

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 at December 31, 2006.

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 $63 million, $56 million and $40 million in 2006, 2005 and 2004, respectively. We did not contribute to the pension plan in 2006, 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 $37 million, $42 million and $44 million in 2006, 2005 and 2004, 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 $24 million, $32 million and $34 million in 2006, 2005 and 2004, respectively. We expect to contribute $13 million to retiree health care and life insurance plans in 2007.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $11 million each were incurred in 2006, 2005 and 2004.

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, 2006, 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)	2007	2008	2009	2010	2011	Thereafter	Total
Purchased electric capacity[1]	$ 414	$ 383	$ 362	$ 349	$ 348	$ 2,207	$ 4,063

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2006, the present value of our total commitment for capacity payments is $2.6 billion. Capacity payments totaled $437 million, $472 million and $570 million, and energy payments totaled $291 million, $378

million and $293 million for 2006, 2005, and 2004, respectively.

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. The lease agreements expire on various dates and certain of the leases are renewable and contain options to purchase the leased property. Payments under certain leases are escalated based on an index such as the Consumer Price Index (CPI). 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, 2006 are as follows:

2007	2008	2009	2010	2011	Thereafter	Total
(millions)						
$28	$25	$19	$16	$13	$27	$128

Rental expense totaled $34 million, $32 million and $40 million for 2006, 2005 and 2004, 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.

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. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments as discussed later under *2007 Virginia Restructuring Act Amendments.*

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SUPERFUND SITES

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

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. Regarding the Pennsylvania site, in March 2006, a federal district court approved three consent decrees between the U.S. and the PRPs, under which we and certain other PRPs, all of which are utilities, will perform the site remediation. The remediation costs are expected to be in the range of $11 million to $18 million, the majority of which are to be paid by the non-utility site owners. After evaluating the impact of these actions, we have reduced our current reserve from $2 million to less than $1 million to meet our potential obligations at these two sites. We generally seek to recover our costs associated with environmental remediation from third-party insurers. At December 31, 2006, no pending or possible insurance claims were 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 2006 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.

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 U.S., 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 $50 million. Based on the severity of the incident, the board of directors of our nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. We have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

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

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

SPENT NUCLEAR FUEL

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into a contract with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contract with the DOE. In January 2004, we, with Dominion, filed a lawsuit in the U.S. Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. Trial is scheduled for March 2008. We will continue to manage our spent fuel until it is accepted by the DOE.

Litigation

We are co-owners with ODEC of the Clover 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 provided 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. On September 1, 2006, the court entered an order directing us and ODEC to correct invoices

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from December 1, 2003 to the present by calculating rates under the higher rate adjustment factor as if it had been applied from the inception of the agreement, to tender the difference to Norfolk Southern with interest at the rate provided by the agreement and to calculate future invoices using the higher rate adjustment factor as if it had been applied from the inception of the agreement. The cumulative amount of the adjustment as of the time the court entered its order was approximately $50 million plus interest, of which our share would be one half. We and ODEC have filed a notice of appeal to the Virginia Supreme Court and have posted security to suspend execution of the judgment during the appeal. We believe the court s interpretation of the transportation agreement and its ruling on other issues in the case are legally incorrect. No liability has been recorded in our Consolidated Financial Statements related to this matter.

Guarantees and Surety Bonds

As of December 31, 2006, we had issued $6 million of guarantees primarily to support commodity transactions of subsidiaries. We had also purchased $68 million of surety bonds for various purposes, including the posting of security to suspend execution of the judgment during the appeal of the Norfolk Southern matter, as discussed in *Litigation*, and providing workers compensation coverage. Under the terms of surety bonds, we are obligated to indemnify the respective surety bond company for any amounts paid.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at December 31, 2006, 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

Stranded costs are 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. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. 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 risks 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 Virginia Electric Utility Restructuring Act was enacted in 1999 (1999 Virginia Restructuring Act) and established a plan to restructure the electric utility industry in Virginia. Under the 1999 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. The 1999 Virginia Restructuring Act permits wires charges to be collected by utilities until July 1, 2007. Our wires charges are set at zero in 2007 for all rate classes, and as such, Virginia customers will not pay the fee if they switch from us to a competitive service provider.

Virginia Fuel Expenses

In May 2006, Virginia law was amended to modify the way our Virginia jurisdictional fuel factor is set during the three and one-half year period beginning July 1, 2007. The bill became law effective July 1, 2006 and:

n

Allows annual fuel rate adjustments for three twelve-month periods beginning July 1, 2007 and one six-month period beginning July 1, 2010 (unless capped rates are terminated earlier under the 1999 Virginia Restructuring Act);

- Allows an adjustment at the end of each of the twelve-month periods to account for differences between projections and actual recovery of fuel costs during the prior twelve months; and
- Authorizes the Virginia Commission to defer up to 40% of any fuel factor increase approved for the first twelve-month period, with recovery of the deferred amount over the two and one-half year period beginning July 1, 2008 (under prior law, such a deferral was not possible).

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, 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. While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

2007 Virginia Restructuring Act Amendments

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5-Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5-Mw. Also after the end of capped rates, the Virginia Commis -

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sion would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
  - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
  - may authorize performance incentives if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the CPI in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the CPI;
  - shall increase base rates if needed to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE;
  - may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
  - may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

The bills would also continue statutory provisions directing us to file annual fuel cost recovery cases with the Virginia Commission beginning in 2007 and continuing thereafter. However, our fuel factor increase as of July 1, 2007 would be limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of that date, and the remainder would be deferred and collected over three years, as follows:

- in calendar year 2008, the deferral portion collected is limited to an amount that results in residential customers not receiv ing an increase of more than 4% of total rates as of January 1, 2008;
- in calendar year 2009, the deferral portion collected is limited to an amount that results in residential customers not receiving an increase of more than 4% of total rates as of January 1, 2009; and
- the remainder of the deferral balance, if any, would be collected in the fuel factor in calendar year 2010.

The Governor has until March 26, 2007 to sign, propose amendments to, or veto the bills. With the Governor s signature, the bills would become law effective July 1, 2007. At this time, we cannot predict the outcome of these legislative proposals.

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,	**2006**		2005	
				Estimated
(millions)	**Carrying Amount**	**Estimated Fair Value(1)**	Carrying Amount	Fair Value(1)

Long-term debt[(2)]	**$ 4,254**	**$ 4,236**	$ 3,874	$ 3,887
Junior subordinated notes payable to affiliated trust	**412**	**422**	412	423
Note payable to Dominion	**220**	**236**	220	230

(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, 2006 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 potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2006, our gross credit exposure totaled $51 million. Of this amount, 93% related to a single counterparty; however, the entire balance is with investment grade entities. We held no collateral for these transactions at December 31, 2006.

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.

Transactions with Affiliates

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

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.

At December 31, 2005 we transferred VPEM to Dominion in exchange for a $633 million contribution of capital. In doing so, we are no longer involved in facilitating Dominion s enterprise risk management by entering into certain financial derivative commodity contracts with affiliates. During 2006, VPEM continued to provide fuel management services to us by acting as an agent for one of our other indirect wholly-owned subsidiaries. In December 2006, we entered into an agreement with VPEM which enables us to directly transact with VPEM for the purchase and sale of fuel and the transportation of fuel to our facilities. This agreement has been approved by the Virginia Commission and the North Carolina Commission and became effective January 2007.

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

Year Ended December 31, (millions)	**2006**	2005	2004
Commodity purchases from affiliates	**$ 234**	$ 364	$ 227
Services provided by affiliates	**311**	292	264
Services provided to affiliates	**26**	26	25

At December 31, 2006, our Consolidated Balance Sheet includes derivative liabilities with affiliates of $2 million. There were no derivative liabilities with affiliates at December 31, 2005. Unrealized gains or losses, representing the effective portion of the changes in fair value of those derivative contracts that had been designated as cash flow hedges, are included in AOCI in our Consolidated Balance Sheets.

We lease an 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 $3 million and $5 million at December 31, 2006 and 2005, respectively. The rental payments for this lease were $3 million each in 2006, 2005 and 2004.

We have borrowed funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2006 and 2005, our nonregulated subsidiaries had outstanding borrowings, net of repayments, under the Dominion money pool of $140 million and $12 million, respectively. At December 31, 2006 and 2005, our borrowings from Dominion under a long- term note totaled $220 million. There were no short-term demand note borrowings at December 31, 2006 and 2005. We incurred interest charges related to our borrowings from Dominion of $10 million, $9 million and $6 million in 2006, 2005 and 2004, respectively.

In 2004, as approved by the 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. 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 a 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, $30 million and $31 million of interest expense on the junior subordinated notes payable to affiliated trust in 2006, 2005 and 2004, respectively.

NOTE 25. OPERATING SEGMENTS

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 businesses. The Delivery segment is subject to cost-of-service rate regulation and accordingly, applies SFAS No. 71.

Energy includes our regulated 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, power purchase agreements and our energy supply operations.

Corporate includes our corporate and other functions. The contribution to net income by our primary operating segments is determined based on a measure of profit that management believes represents the segments   core earnings. As a result, certain specific items attributable to those segments have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among

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the segments, including the discontinued operations of VPEM prior to its transfer to Dominion.

In 2006, the Corporate segment includes $12 million of net expenses attributable to our Generation segment. The net expenses in 2006 related to the following:

- A $13 million ($8 million after-tax) impairment charge in the fourth quarter resulting from a change in our method of assessing other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts; and
- A $7 million ($4 million after-tax) charge resulting from the write-off of certain assets no longer in use at one of our electric generating facilities.

In 2005, the Corporate segment included $58 million of net expenses 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, the Corporate segment included $155 million of net expenses 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 Isabel restoration activities, attributable to Delivery.

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	Delivery	Energy	Generation	Corporate	Adjustments & Eliminations	Consolidated Total
2006						
Operating revenue	**$ 1,182**	**$ 214**	**$ 4,202**	**$ 5**	**$**	**$ 5,603**
Depreciation and amortization	**259**	**34**	**225**	**18**		**536**
Interest and related charges	**107**	**22**	**173**		**(6)**	**296**
Income tax expense (benefit)	**170**	**42**	**80**	**(8)**		**284**
Net income (loss)	**270**	**69**	**151**	**(12)**		**478**
Capital expenditures	**395**	**129**	**523**			**1,047**
Total assets	**5,453**	**1,595**	**9,250**		**(615)**	**15,683**
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

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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, 2006 and 2005 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2006					
Operating revenue	**$ 1,333**	**$ 1,323**	**$ 1,690**	**$ 1,257**	**$ 5,603**
Income from operations	**206**	**185**	**385**	**207**	**983**
Net income	**97**	**86**	**209**	**86**	**478**
Balance available for common stock	**93**	**82**	**205**	**82**	**462**
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 principle	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)

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.

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

In accordance with FIN 46R, we have included in our Consolidated Financial Statements a VIE through which we have financed and leased a power generation project. Our Consolidated Balance Sheet as of December 31, 2006 reflects $337 million of net property, plant and equipment and deferred charges and $370 million of related debt attributable to the VIE. As this VIE is owned by unrelated parties, we do not have the authority to dictate or modify, and therefore cannot assess, the disclosure controls and procedures or internal control over financial reporting 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

Information concerning directors of Virginia Electric and Power Company (VP), 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 (52)	Chairman of the Board of Directors and Chief Executive Officer (CEO) of VP from February 2006 to date; President and CEO of Dominion Resources, Inc. (DRI) from January 2006 to date; Director of DRI from March 2005 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to date; President and Chief Operating Officer (COO) of DRI from January 2004 to December 2005; President and COO of CNG from January 2004 to December 2005; Executive Vice President of DRI from March 1999 to December 2003; President and CEO of VP from December 2002 to December 2003; Executive Vice President of CNG from January 2000 to December 2003; CEO of VP from May 1999 to December 2002.	1999
Thomas N. Chewning (61)	Executive Vice President and Chief Financial Officer (CFO) of VP from February 2006 to date; Executive Vice President and CFO of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to date; Director of CNG from December 2002 to date.	1999

Audit Committee Financial Experts

We are a wholly-owned subsidiary of DRI. As permitted by Securities and Exchange Commission (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.

Information concerning the executive officers of VP, each of whom is elected annually is as follows:

Name and Age	Business Experience Past Five Years
Thomas F. Farrell, II (52)	Chairman of the Board of Directors and CEO of VP from February 2006 to date; President and CEO of DRI from January 2006 to date; Chairman of the Board of Directors, President and CEO of CNG from January 2006 to date; Director of DRI from March 2005 to date; President and COO of DRI from January 2004 to December 2005; President and COO of CNG from January 2004 to December 2005; Executive Vice President of DRI from March 1999 to December 2003; President and CEO of VP from December 2002 to December 2003; Executive Vice President of CNG from January 2000 to December 2003; CEO of VP from May 1999 to December 2002.
Thomas N. Chewning (61)	Executive Vice President and CFO of VP from February 2006 to date; Executive Vice President and CFO of DRI from May 1999 to date; Executive Vice President and CFO of CNG from January 2000 to date.
Jay L. Johnson (60)	President and COO Delivery of VP from February 2006 to date; Executive Vice President of DRI from January 2004 to date; President and CEO of VP from December 2002 to January 2006; Executive Vice President of CNG from December 2002 to date; Senior Vice President, Business Excellence, Dominion Energy, Inc. (DEI) from September 2000 to December 2002.

Paul D. Koonce (47)	Executive Vice President of DRI from April 2006 to date; President and COO Energy of VP from February 2006 to date; CEO Energy of VP from January 2004 to January 2006; CEO Transmission of VP from January 2003 to December 2003; Senior Vice President Portfolio Management of VP from January 2000 to December 2002.
Mark F. McGettrick (49)	Executive Vice President of DRI from April 2006 to date; President and COO Generation of VP from February 2006 to date; President and CEO Generation of VP from January 2003 to January 2006; Senior Vice President and Chief Administrative Officer of DRI from January 2002 to December 2002; President of Dominion Resources Services, Inc. (DRS) from October 2002 to January 2003.
David A. Christian (52)	Senior Vice President Nuclear Operations and Chief Nuclear Officer from April 2000 to date.
Steven A. Rogers (45)	Senior Vice President and Chief Accounting Officer of VP, DRI and CNG from January 2007 to date; Senior Vice President (Principal Accounting Officer) (PAO) of VP from April 2006 to December 2006; Senior Vice President and Controller of DRI and CNG from April 2006 to December 2006; Vice President, Controller and PAO of DRI and CNG and Vice President and PAO of VP from June 2000 to April 2006.
	Any service listed for DRI, DEI, DRS and CNG reflects services at a parent, subsidiary or affiliate. There is no family relationship between any of the persons named in response to Item 10.

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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.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

We are a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell and Chewning, who are executive officers of the Company and are not independent. Because our Board believes that it is more appropriate for our compensation program to be managed under the direction of individuals who are independent, we do not have a compensation committee. Instead, our Board depends on the advice and recommendations of Dominion s Compensation, Governance and Nominating Committee (CGN Committee), which is comprised of independent directors and has retained the consulting firm of Pearl Meyer & Partners (PMP) to advise them on compensation matters. Our Board approves all compensation paid to VP s executive officers based on Dominion s CGN Committee s recommendations. Neither of our directors, who are officers of the Company and Dominion, receive any compensation for the services they provide as directors. Dominion s CGN Committee effectively administers one compensation program for all of Dominion.

Executive Compensation Philosophy The Objectives of Dominion s Program

Dominion s executive compensation program is designed to attract, motivate and retain a superior management team, while ensuring that annual and long-term incentive programs align management s financial success with that of Dominion s shareholders. Dominion s management and Board of Directors, through the oversight of the CGN Committee, believe in putting a substantial portion of our senior executives compensation at risk based on performance goals established by the CGN Committee. While Dominion benchmarks and sets general compensation levels relative to its peer group of companies (detailed below) and market data in general, it administers the program to meet the needs and requirements of Dominion. This takes into consideration internal equity, experience, scope of responsibility and other concerns. Market data is used as a reality check in evaluating our compensation decisions for our senior executives.

Our Process

Each year, the executive compensation program is comprehensively assessed and analyzed. The review process includes, but is not limited to, the following steps:

- A peer group of companies is identified and Dominion is compared with these peer companies based on a number of different financial and stock performance metrics for a number of different measurement periods;
- The CGN Committee reviews the performance of the CEO and other senior officers, including the CEO s assessment of the performance of other key officers, and his views on succession and retention issues (our Company and Dominion have the same CEO and CFO);
- The current annual compensation of senior management, and long-term compensation grants made over the past few years are reviewed;
- The appropriate performance metrics and attributes of annual and long-term programs for the next year are considered and discussed;
- The entirety of our compensation program is considered, including periodic reviews of specific benefits and perquisites;
- Base pay, annual incentive pay, long-term pay and total compensation for individual officers are benchmarked against survey data using appropriate job matches and comparable asset and revenue size. The survey data is based on a number of purchased surveys from Mercer HR Consulting, Towers Perrin and other organizations, including industry specific surveys whenever possible. The industry specific surveys provide information on positions at companies of similar size or revenue scope, or general industry data on positions for which we may compete;
- For top officers, if peer group compensation is available for their position, Dominion uses a blend of survey and peer compensation for comparison, as there is competition not only in our own market, but nationally and across industries, for talent;
- The compensation practices of our peer companies are reviewed, including their practices with respect to equity and other grants, benefits and perquisites;
-

The compensation of the management team from the standpoint of internal equity, complexity of the job, scope of responsibility and other factors is assessed; and

- Specific market-based conditions and other circumstances for certain executives and competitive business groups are considered.

Dominion s management has the following involvement with the executive compensation process:

- Dominion s Financial Planning group identifies companies for inclusion in the peer group based on our industry and the companies used by Dominion analysts and external analysts for comparison purposes. Both Dominion s CFO and the CGN Committee s independent compensation consultant, a managing director of PMP, review and comment on the proposed group before it is submitted to the CGN Committee for approval;
- Dominion s CEO and CFO are both involved in establishing and recommending to the CGN Committee financial goals for the incentive programs based on management s operational goals and strategic plans; and
- Dominion s CEO reviews recommendations from Dominion s director of executive compensation and PMP regarding salaries, annual and long-term incentive targets, and plan amendments and design before recommendations are made to the CGN Committee. While he reviews and makes recommendations for officers, Dominion s CEO does not make any recommendations or review proposals with regard to his own compensation, with only the CGN Committee having the authority to approve compensation for the senior executives. Also, our independent compensation consultant meets with the CGN Committee, without management present, to review her recommendations. Dominion s CEO and CFO are also involved in making recommendations about the timing and frequency of long-term programs, special arrangements to

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address specific concerns and the elimination or modification of certain benefits.

- Our Board reviews information provided by and considers for approval compensation matters recommended by the CGN Committee.

The Peer Group and Peer Group Comparisons

Dominion s peer group is generally consistent from year to year, with merger and acquisition activity being the primary reason for any changes. The 2006 peer group for compensation-setting purposes consisted of a diversified group of ten energy companies: American Electric Power Company, Inc.; Constellation Energy Group, Inc.; Duke Energy Corporation; Entergy Corporation; Exelon Corporation; First Energy Corporation; FPL Group, Inc.; Progress Energy, Inc.; Southern Company and TXU Corp.

The CGN Committee, PMP and Dominion s executive compensation department use the peer company data to (i) compare Dominion s stock and financial performance against these peers using a number of different metrics and time periods; (ii) analyze compensation practices within the industry; and (iii) benchmark other benefits such as Employment Continuity Agreements and the use of long-term equity vehicles.

Elements of Dominion s Compensation Program

Our executive compensation program consists of three basic components:

- Base Salary
- Annual Incentives
- Long-Term Incentives

BASE SALARY

Base salary compensates officers, along with the rest of the workforce, for committing significant time to working on the Company s behalf. In considering annual salary increases, the following factors are assessed: (i) the competitive labor market; (ii) changes in an officer s scope of responsibility, including promotions; and (iii) individual performance, special skills, experience and other relevant considerations.

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

For 2006 base compensation, all officers received a base salary adjustment of at least 4%. Some officers received salary adjustments in excess of 4% for one of the following reasons: (i) increase or other change in job responsibility; (ii) specific market-based reasons; (iii) exceptional performance; (iv) unique retention or job competitiveness reasons; and/or (v) internal pay equity. Mr. Farrell received a 29% increase in base salary in 2006, when he assumed the duties of CEO of Dominion. Even with this increase, his base salary and targeted total cash compensation were below the median for his peers. The CGN Committee determined to bring his base salary to the market median over the course of a few years, based on his achievements and performance in office. The remaining named executive officers received the following 2006 base salary increases: Mr. Chewning 13.6%; Mr. McGettrick 26.5%; Mr. Johnson 10%; and Mr. Christian 12%. Mr. Chewning s increase resulted

in his base pay being slightly above market median in recognition of his experience and superior job performance, and the complexity and scope of his responsibilities. Messrs. McGettrick and Johnson s base salaries continued to lag behind the market median based on the increasing size of their business units, the effects of several years with no or below market increases in base salary. Messrs. McGettrick and Johnson s increases were aimed at bringing their base salaries closer to market median. Messrs. McGettrick and Christian s increases were also due to the competitive nature of their positions and to reward excellent performance.

ANNUAL AND LONG-TERM INCENTIVE PROGRAMS

Annual and long-term incentive programs continue to play a critical role in Dominion s compensation practices and our philosophy of aligning the interests of officers with those of Dominion s shareholders while rewarding performance. The annual incentive program is a cash-based program focused on short-term goal accomplishments. The long-term incentive program is weighted equally between a retention component (restricted stock) and a performance component (cash-based performance grant).

Performance-Based Compensation. The performance-based components of Dominion s incentive program (annual incentive plan and the cash performance grants of our long-term program) motivate and encourage officers and employees to achieve operational excellence that will benefit Dominion s shareholders. Dominion uses a blend of goals focused on Dominion s financial achievements overall, specific business unit goals and individual goals. These components allow Dominion to encourage and reward officers and employees for achieving financial goals, as well as operating and stewardship goals such as safety and individual power plant performance.

Annual and long-term incentives are an industry standard and a best practice to motivate employees to achieve performance goals for a portion of their compensation. Performance-based compensation is a large part of executives compensation, with senior officers having the most compensation at risk based on performance. This correlates with the influence and responsibility each level of management has for delivering financial results.

For our CEO, Mr. Farrell, just over 50% of his targeted total compensation (annual and long term) is at risk and depends on the achievement of performance goals. For the other named executive officers, targeted compensation at risk ranged from 49% to 44%, and for a typical vice president, the percentage of targeted compensation at risk is approximately 38%. This compares to an average of approximately 11% of total pay at risk for non-officer employees. This structure ensures that if performance goals are not achieved, the officers have compensation that could be significantly lower than market median depending on the extent goals are missed. If performance goals are exceeded, officers will receive compensation that is close to or at the market 75^{th} percentile, depending on the extent that goals are exceeded. Additionally, a substantial portion of each officer s total compensation is tied to the performance of Dominion s stock through their restricted stock grants, ranging from 18% of targeted total compensation for a typical vice president up to 37% for Mr. Farrell. For Mr. Farrell, this results in almost 90% of his total direct compensation having a performance component.

Dominion s Board may seek to recover performance-based compensation paid to officers who are found to be personally responsible for fraud, negligence or intentional misconduct that causes a restatement of financial results filed with the SEC.

Annual Incentive Plan. The Annual Incentive Plan focuses on short-term goals, and for the CEO, comprised more than half of his annual cash compensation for 2006. With the introduction of cash-based performance grants in 2006 as outlined below, the CEO and

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each eligible officer may receive a higher percentage of their total 2007 compensation (annual and long-term) earned in cash, based on goal accomplishment.

Under the Annual Incentive Plan, the CGN 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 plan is fully funded and the executive achieves 100% of the goals established at the beginning of the year. Under the Annual Incentive Plan, 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. If the goals are not achieved, the executive s total cash compensation may be significantly lower than market median, depending on the extent to which goals were not achieved. For 2006, Mr. Farrell s annual incentive target was 110% of his base salary, consistent with our intent of having a substantial portion of his compensation at risk. For 2006, Mr. Chewning s target was 90%, Messrs. McGettrick and Johnson s target was 80%, and Mr. Christian s target was 70%.

The 2006 Annual Incentive Plan was funded based on goals established and approved by the CGN Committee at the beginning of 2006. For the 2006 Annual Incentive Plan, the threshold consolidated earnings goal for any payout under the plan was reported operating earnings for Dominion of $5.05 per share, with full funding at reported operating earnings of $5.15 per share. Additionally, if Dominion s reported operating earnings exceeded $5.15 per share, then for every one cent reported over $5.15 per share, 3% in additional funding would be applied to the 2006 Annual Incentive Plan, up to a maximum of 200% funding. This results in the Company and employees sharing equally in earnings above the $5.15 per share goal until the 200% maximum funding level is achieved.

To access the funded bonus pool, each executive must meet certain goals, including consolidated and business unit financial goals as well as operating, stewardship and Six Sigma targets. The consolidated earnings goal is designed to drive employee behavior and performance to ensure that shareholders receive an appropriate return on their investment in Dominion.

The business unit financial goals are set based on the levels necessary to achieve the consolidated earnings goal for Dominion. Also, individual business unit goals provide line-of-sight targets for officers and employees, and facilitate financial and business planning at the business unit level.

The operating and stewardship goals may not be financial, and can be customized for a business unit or individual. The accomplishment of these goals often supports the business unit financial goals. The most common operating and stewardship goals have objectives in the following areas: safety; reliability; expenditures and production; forced outages; and service level requirements.

Finally, Six Sigma goals support Dominion s mission to continue to use Six Sigma to increase productivity, improve service reliability, reduce costs and enhance customer service while bringing the benefits of these improvements to the bottom line.

Each executive s goals are weighted according to his or her responsibilities. Payout under the plan is determined by multiplying the employee s target bonus by the percentage the plan is funded (e.g., 100%) by the percentage that the employee s own personal goal package is achieved (e.g., 90%).

The goal weightings for bonuses under the 2006 Annual Incentive Plan for Dominion s named executive officers (which includes Messrs. Farrell, Chewning, McGettrick and Johnson) and all other officers (which includes Mr. Christian) were as follows:

	Consolidated Financial Goal	Business Unit Financial Goals	Operating/ Stewardship	Six Sigma
Dominion s named executive officers	100%	0%	0%	0%
Other officers	25%	50%	15%	10%

For Messrs. Farrell, Chewning, McGettrick and Johnson, bonuses were based solely on the consolidated earnings goal, with the CGN Committee having discretion to reduce final payouts to the extent appropriate, based on any goal accomplishment that was less than 100% for the corporate-wide Six Sigma goal, and for Messrs. McGettrick, Johnson and Christian, any goal accomplishment that was less than 100% for their business unit financial goals or their own personal operating/stewardship goals. The reductions could be as much as the percentages set forth in the table above for each category for other officers. Due to the broad scope of their duties, Messrs. Farrell and Chewning did not have operating and stewardship goals, as these goals tend to be business-unit specific.

Dominion compared actual financial performance for 2006 with the consolidated and business unit earnings goals. Dominion achieved operating earnings of $5.17 per share in 2006 before any additional funding under our plan. Taking into account the funding formula described above, the 2006 Annual Incentive Plan was funded at the 103% level, with additional 3% funding available to cover any upside from the Six Sigma stretch goals described above. Dominion reported $5.16 per share in operating earnings as a result of funding these additions, with shareholders and employees each receiving one cent each of the operating earnings over $5.15 per share.

The Six Sigma goal for 2006 was a corporate-wide positive financial impact of $100 million, with a stretch goal of $150 million, which would result in an increase of 4% in each employee s payout score if the stretch goal were achieved. Dominion as a whole and each business unit exceeded their Six Sigma stretch goal, with corporate-wide savings of $224 million achieved in 2006. This resulted in all employees, except for Dominion s named executive officers (which includes Messrs. Farrell, Chewning, McGettrick and Johnson), receiving an additional 4% to their pay-out score for determining 2006 payouts, with a total possible payout of 107% of their target bonus. Dominion s named executive officers received 106% plan funding because their bonuses were based on consolidated earnings goals only, including the earnings kicker; however, their goal score was capped at 100%. Actual amounts earned under the 2006 Annual Incentive Plan by each of the Company s named executive officers are set forth in the Summary Compensation Table under the heading Non-Equity Incentive Plan Compensation .

The Long-Term Incentive Program. For 2006, Dominion transitioned its long-term program from retention-based restricted stock, with alignment to its shareholders, to a long-term program that is both (i) aligned with the long-term interests of its shareholders through restricted stock grants and (ii) designed to put a substantial portion of the long-term compensation at risk based on the achievement of performance measures with the introduction of cash performance grants. Grants are typically made on or before April 1 of each year, and Dominion does not time the grant dates based on the release of material information or expectations of stock price changes. Newly promoted officers receive pro-rated grants for the current year s program based on the fair market value of the stock as of their date of employment or election to office.

Dominion has not issued stock options since 2002, although options remain outstanding from prior programs and are reported in the Outstanding Equity Awards at Fiscal Year End table on page 58, with options exercised in 2006 disclosed in the Option Exercises and Stock Vested table on page 59.

While the CGN Committee reviews prior grants to the CEO before approving new long-term grants, the determination of the appropriate grant for the CEO and other senior executives in any given year is based on the results of the process described above for the executive compensation program. Dominion does not deduct prior compensation paid to executives from the compensation being considered for the current year. Similarly, if a newer executive does not have prior grants outstanding due to his or her short tenure, Dominion does not increase the compensation paid to the executive due to a lack of outstanding grants from prior years.

Performance Grants. For 2006, Dominion transitioned to a long-term incentive program that is 50% performance-contingent, payable in cash rather than stock. These grants were made on April 1, 2006 and are at-risk based on the achievement of the two goals discussed below. The reasons for shifting a portion of the program to cash were (i) the significant ownership of Dominion stock by executives and the high rate of compliance with our share ownership requirements; (ii) to provide a more immediate award following achievement of goals and (iii) improve the tax efficiency of awards as no shares need to be sold to pay taxes, and any net cash award could be used to pay taxes on vesting restricted stock awards. Officers who have not achieved their ownership targets are expected to hold vested restricted stock, net of shares used to cover taxes.

The 2006 cash-based performance grants have a two-year term, with two equally weighted goals: i) Dominion s total shareholder return (TSR) for the 21 month period ended December 31, 2007 relative to the TSR of a group of industry peers selected by the CGN Committee; and ii) return on invested capital (ROIC) for the two-year period ended December 31, 2007. For the performance grants which were awarded in April 2006, the 2006 peer group was adjusted and NiSource, Inc. and PPL Corporation added to the peer group, and Constellation Energy Group was excluded for this grant as it was a merger candidate at that time. The grants are 100% performance-based with payouts ranging from 0-200% of target. The goals for the 2006 grant, scoring for such goals and possible payouts for the named executive officers are set forth in the Grants of Plan-Based Awards table on page 57.

Restricted Stock Grants. Officers also received restricted stock grants on April 1, 2006. The grants have cliff vesting at the end of the three-year restricted period. Restricted stock grants serve as a retention tool as they are forfeited upon voluntary termination and align the interests of officers with the interests of our shareholders.

The CGN Committee approved the 2006 long-term grants based on a stated dollar value for the award based on its earlier compensation review. Restricted stock was issued for 50% of the total long-term grant value, with the number of shares issued

determined by using the fair value of Dominion s common stock the day before the date of grant (average of high and low stock price). Officers receive dividends on the restricted shares. The full grant date fair value of each named executive officer s 2006 restricted stock grant is disclosed in the Grants of Plan-Based Awards table on page 57.

Vesting Terms for the 2006 Restricted Stock Grants and Performance Grants. Both grants are forfeited in their entirety if the officer voluntarily terminates his or her employment or is terminated with cause before the vesting date. The grants have pro-rated vesting for termination without cause, retirement, death or disability, rewarding the officers or their estate only for the period of time they provided services to the company. For the performance grants, the pro-rated payout is based on actual goal performance at the end of the performance cycle.

In the event of a Change in Control* at Dominion, the restricted shares have pro-rated vesting up to the change in control date, rewarding officers only for prior service. If the officers subsequently are terminated, or constructively terminate their employment, under the terms of the grant, any remaining unvested shares will vest at that point. For the cash performance grants, as any goals would likely be materially changed as a result of any Change in Control at Dominion, payout of these grants will accelerate and will be equal to the greater of the target grant amount or the payout that would be made based on the assumptions used for goal performance in Dominion s latest financial statements as of the day before the Change in Control occurred.

EMPLOYEE AND EXECUTIVE BENEFITS

Officers participate in many of the same employee benefit programs as other employees. The core benefit programs include two tax-qualified retirement plans, vacation program, medical coverage, dental coverage, vision coverage, life insurance, disability coverage, travel accident coverage, company-paid short-term disability and long-term disability coverage. There are other miscellaneous employee benefit programs, such as flexible spending accounts, health savings accounts, employee assistance programs, employee leave policies and other incidental programs available to employees generally. Tax-qualified retirement plans are a 401(k) plan and a defined benefit pension plan (Pension Plan). A matching contribution to each employee s 401(k) plan account of 50 cents for each dollar is made on the first 6% of compensation (up to IRS limits) if less than 20 years of service, and 67 cents for each dollar contributed on the first 6% of compensation (up to IRS limits) if the employee has at least 20 years of service. The amount of the company matching contributions under the 401(k) for the named executive officers ranged from $1,980 to $4,400. Amounts forgone due to IRS limits were paid to executives in cash and ranged from $3,312 to $8,192. All of these matching contribution amounts are shown in the All Other Compensation footnote to the Summary Compensation Table following this section**.** The defined benefit pension plan pays benefits under a formula that is explained in *Pension Benefits* and the change in pension value for 2006 is included in the Summary Compensation table on page 56.

* A Change in Control occurs 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.

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Dominion also has two supplemental retirement plans for executives. The Benefit Restoration Plan makes up for certain limits related to Pension Plan benefits imposed by the Internal Revenue Code as more fully explained in *Pension Benefits* beginning on page 59. The Pension Plan and Benefit Restoration Plan pay benefits calculated on base salary. To accommodate changes in tax law, the Dominion Benefit Restoration Plan was frozen as of December 31, 2004 (Frozen BRP) and a New Benefit Restoration Plan was implemented effective January 1, 2005 (New BRP). There is no change in the total benefit provided as a result of this new plan.

The Executive Supplemental Retirement Plan provides an annual retirement benefit equal to 25% of a participant s final cash compensation (base salary plus target annual bonus) for a period of ten years or life as more fully explained in *Pension Benefits*. To accommodate changes in the tax law, the Executive Supplemental Retirement Plan was frozen as of December 31, 2004 (Frozen ESRP) and a New Executive Supplemental Retirement Plan was implemented effective January 1, 2005 (New ESRP). There is no change in the benefit provided as a result of this new plan.

Dominion maintains the Benefit Restoration Plan and the Supplemental Retirement Plan to provide a competitive level of retirement benefits to our executives. The Pension Plan and its related Benefit Restoration Plan provide a benefit that is calculated on base salary, credited age, credited service and a social security off-set. Because a more substantial portion of our executives total compensation is paid as incentive compensation than for rank and file employees, the Pension Plan and Benefit Restoration Plan alone would not produce the same percentage of replacement income in retirement for executives as for rank and file employees. The Supplemental Retirement Plan is intended to partially make up for the limitation of these two plans due to their use of base salary only. The Supplemental Retirement Plan includes bonuses in its calculations, but does not include long- term incentive compensation. As a result, a significant portion of the potential compensation for our executives are excluded from calculation in any retirement plan benefit. The present value of accumulated benefits under these plans are disclosed in the Pension Benefits table on page 59.

Dominion also maintains a voluntary Executive Life Insurance Program for our executives. The plan provides for whole-life insurance policies to executives with a death benefit that is a multiple (one to three times) of each executive s base salary. This insurance is in addition to the term insurance that is provided as an employee benefit. The executive is the owner of the policy and the company will make premium payments to the later of 10 years or age 64. Executives are taxed on the value of the insurance provided by the company. The premiums for these policies are included in the All Other Compensation footnote to the Summary Compensation Table.

Perquisites. Dominion provides perquisites for executives that are considered reasonable by the CGN Committee and in line with market practice. In addition to incidental perquisites associated with maintaining an office, the following limited number of perquisites are offered to executives:

(1) An allowance of up to $9,500 a year for financial, estate and tax planning as well as for health and physical well being services. Dominion wants executives to be proactive with preventative healthcare and financial and estate planning and to ensure proper tax reporting of company-provided compensation.

(2) A company-leased vehicle, including the cost of insurance, gas and maintenance, up to an established lease-payment allowance (if the lease payment exceeds the allowance, the officer pays for excess amounts on the vehicle personally). Dominion offers this perquisite to be competitive with other comparable employers.

(3) Luncheon or other club memberships to provide a venue for business entertainment purposes. In 2007, Dominion is eliminating this perquisite.

(4) In limited circumstances, use of company aircraft for personal travel. Dominion s Board has required Mr. Farrell to use the aircraft for personal travel for reasons of security. Other executives use of the aircraft is very limited, and usually related to (i) travel with the CEO or (ii) personal travel to accommodate business demands on the executives schedule. Executives are taxed on all personal use of aircraft under IRS guidelines. Other than Mr. Farrell, the personal use of aircraft is not allowed when there is a company need for the aircraft. Use of the corporate aircraft saves our executives substantial time and allows better access to the executives for company purposes. Over 96% of the use of Dominion s company planes is for business purposes.

Tax Gross-Up. While these perquisites are generally taxable, the company provides a tax gross-up for the limited personal use of the company plane that does occur, spousal travel or expenses for business entertainment purposes and in a limited number of cases, clubs. As mentioned above, we will no longer pay for any clubs and therefore there will no longer be associated taxes or gross-ups on those clubs.

Other Agreements. In order to secure and retain the services and focus of key executives, Dominion has entered into agreements with each of our named executive officers to provide certain retirement benefits or other protections in certain circumstances, including Employment Continuity Agreements with each executive. The specific terms of these agreements are discussed in *Pension Benefits* and the tables under *Potential Payments upon Termination or Change in Control*.

Deductibility of Compensation

Under Section 162(m) of the Internal Revenue Code, Dominion may not deduct certain forms of compensation in excess of $1 million paid to its CEO or any of the four other most highly compensated executive officers. However, certain performance-based compensation is specifically exempt from the deduction limit.

It is Dominion s intent to provide competitive executive compensation while maximizing its tax deduction to the extent reasonable. The CGN Committee considers the Section 162(m) implications when approving certain plans and payouts. However, the CGN Committee reserves the right to approve, and in some cases has approved, non-deductible compensation if they believe it is in Dominion s best interest.

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SUMMARY COMPENSATION TABLE[1]

Name and Principal Position	Year	Salary	Stock Awards[2]	Non-Equity Incentive Plan Compensation[3]	Change in Pension Value and Nonqualified Deferred Compensation Earnings[4]	All Other Compensation[5]	Total
Thomas F. Farrell, II *Chief Executive Officer*	2006	$ 350,000	$ 686,742	$ 408,100	$ 915,719	$ 196,025	$ 2,556,586
Thomas N. Chewning *Executive Vice President and Chief Financial Officer*	2006	180,000	311,604	171,720	88,263	112,317	863,904
Mark F. McGettrick *President & COO Generation*	2006	262,500	214,537	214,364	441,558	77,724	1,210,683
Jay L. Johnson *President & COO Delivery*	2006	222,615	199,705	188,778	204,537	98,883	914,518
David A. Christian *Senior Vice President Nuclear Operations and Chief Nuclear Officer*	2006	206,055	126,428	149,606	146,186	52,538	680,813

(1) The executives 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 the year presented.
(2) The amounts in this column reflect the compensation expense recognized in 2006 on all outstanding stock awards in accordance with SFAS 123R. The grant date fair value of restricted stock awards is equal to the market price of our stock on the date of grant. The grant date fair value of each named executive officer s 2006 restricted stock grant is disclosed in the Grants of Plan-Based Awards table on page 57. See also the Outstanding Equity Awards at Fiscal Year-End table on page 58 for a listing of all outstanding equity awards as of December 31, 2006.
(3) The amounts in this column reflect the payout under Dominion s 2006 Annual Incentive Plan. All of the named executive officers except for Messrs. McGettrick and Christian received the full potential payout of their target awards, reflecting 106% funding of the 2006 Annual Incentive Plan and 100% payout for accomplishment of their goals. Messrs. McGettrick and Christian s payouts were reduced to an overall payout of 102% and 104%, respectively, of target due to less than 100% performance on safety and production cost goals. See Compensation Discussion and Analysis (CD&A) for additional information on the 2006 Annual Incentive Plan and the Grants of Plan Based Awards table for the range of each named executive officer s potential award under the 2006 Annual Incentive Plan (with this column reflecting the actual payout for each named executive officer).
(4) All amounts in this column are for the aggregate change in the actuarial present value of the named executive officer s accumulated benefit under our qualified pension plan and nonqualified executive retirement plans. There are no above-market earnings on non-qualified deferred compensation plans. These amounts are not directly in relation to final payout potential, and can vary significantly year over year based on (i) promotions and corresponding changes in salary, such as Mr. Farrell s promotion to Dominion s Chief Executive Officer as of January 1, 2006; (ii) other one-time adjustments to salary or incentive target for market or other reasons; (iii) actual age versus predicted age at retirement; and (iv) other market factors.
(5) **All Other Compensation** amounts for 2006 are as follows

Name	Executive Perquisites (a)	Life Insurance Premiums	Tax Gross-up	Employee Savings Plan Match(b)	Company Match Above IRS	Vacation Sold Back To	Dividends Paid on Restricted	Total All Other Compensation

					Limits[c]	**Company**	**Stock**	
Thomas F. Farrell, II	$ 29,352	$ 19,388	$ 15,017	$ 2,310	$ 8,190	$ 6,731	$ 115,037	$ 196,025
Thomas N. Chewning	19,297	25,693	4,320	1,980	4,560	0	56,467	112,317
Mark F. McGettrick	16,545	12,042	1,671	4,400	6,100	0	36,966	77,724
Jay L. Johnson	23,047	25,699	8,031	3,366	3,312	0	35,428	98,883
David A. Christian	13,579	8,976	0	3,960	4,282	0	21,741	52,538

(a) Unless noted, the amounts in this column for all officers are comprised of the following: personal use of a company vehicle; personal use (except for Messrs. McGettrick and Christian) of corporate aircraft; financial planning; health and wellness allowance; club fees (except for Mr. Christian); and home security system (Mr. Christian only). For Messrs. Farrell and Chewning, personal use of the corporate aircraft was $12,923 and $8,191 respectively. For personal flights, all direct operating costs are included in calculating aggregate incremental cost. Direct operating costs include the following: fuel, airport fees, catering, ground transportation and crew expenses (any food, lodging and other costs). The fixed costs of owning the aircraft and employing the crew are not taken into consideration, as more than 96% of the use of the corporate aircraft is for business purposes. For Mr. Farrell, club fees were $9,294 which includes a one-time transfer fee for a corporate membership for his use while serving as CEO.

While some of the club fees are for personal memberships which may be used for business purposes, a majority of the fees reflected are for corporate memberships. Although we consider corporate club fees as a perquisite, a majority of the use of corporate club memberships is for business purposes. The aggregate incremental cost for club fees is based on actual costs incurred. As of January 1, 2007, the Company is eliminating the club perquisite program for executives, and they will be personally responsible for all dues.

In addition to these formal perquisite programs, executives may also receive some perquisites from time to time that have no incremental cost to the company. These would include (i) use of the company s travel department for making travel arrangements that may have a personal component to them; (ii) flights on the company plane when a seat is available for the spouse or other guest of an executive; (iii) an assigned parking spot; and (iv) occasional use of their administrative assistant or other company employees for assistance with charitable, community or personal matters.

(b) Paid under the terms of the Company s 401(k) plan.

(c) Represents payment of lost savings plan match due to IRS limits. This lost match was paid in cash to the named executive officers outside of the 401(k) plan.

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GRANTS OF PLAN-BASED AWARDS[1]

Name	Grant Approval Date[2]	Grant Date[3]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold	Target	Maximum	All Other Stock Awards: Number of Shares of	Grant Date Fair Value of Stock and Options Award[2]
Thomas F. Farrell, II							
2006 Annual Incentive Plan[3]			$ 0	$ 385,000	$ 770,000		
2006 Performance Grant[4]			$ 0	$ 1,050,000	$ 2,100,000		
2006 Restricted Stock Grant[4]	3/31/2006	4/1/2006				15,101	$ 1,050,004
Thomas N. Chewning							
2006 Annual Incentive Plan[3]			$ 0	$ 162,000	$ 324,000		
2006 Performance Grant[4]			$ 0	$ 300,000	$ 600,000		
2006 Restricted Stock Grant[4]	3/31/2006	4/1/2006				4,315	$ 300,015
Mark F. McGettrick							
2006 Annual Incentive Plan[3]			$ 0	$ 210,000	$ 420,000		
2006 Performance Grant[4]			$ 0	$ 300,000	$ 600,000		
2006 Restricted Stock Grant[4]	3/31/2006	4/1/2006				4,315	$ 300,022
Jay L. Johnson							
2006 Annual Incentive Plan[3]			$ 0	$ 178,092	$ 356,184		
2006 Performance Grant[4]			$ 0	$ 229,500	$ 459,000		
2006 Restricted Stock Grant[4]	3/31/2006	4/1/2006				3,301	$ 229,535
David A. Christian							
2006 Annual Incentive Plan[3]			$ 0	$ 144,239	$ 288,477		
2006 Performance Grant[4]			$ 0	$ 146,250	$ 292,500		
2006 Restricted Stock Grant[4]	3/31/2006	4/1/2006				2,104	$ 146,274
2006 Restricted Stock Grant[5]	12/19/2006	12/20/2006				1,089	$ 90,006

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.

(2) On March 31, 2006, the CGN Committee approved the 2006 long-term compensation awards for our officers which consisted of a restricted stock grant and a performance grant. The 2006 restricted stock award was granted on April 1, 2006. Under Dominion s 2005 Incentive Compensation Plan, fair market value is defined as the average of the high and low prices of Dominion stock as of the last day on which the stock is traded preceding the date of grant. The fair market value for the April 1, 2006 restricted stock grant was $69.53 per share and was determined by taking the average of the high and low prices of Dominion stock on March 31, 2006 (grant approval date).

(3) These amounts represent potential payouts under the 2006 Annual Incentive Plan. Actual payouts earned are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 56. Under the annual incentive program, officers are eligible for an annual performance-based award. The CGN Committee establishes target awards for each executive based on his or her salary level and expressed as a percentage of the individual executive s base salary. The target award is the amount of cash that will be paid if the plan is fully funded. For the 2006 Annual Incentive Plan, funding is based on the achievement of consolidated operating earnings goals with the maximum funding capped at 200%.

For officers that are among Dominion s top most highly compensated group for 2006, which includes all of our named executive officers except for Mr. Christian, pay-out under the 2006 Annual Incentive Plan is based solely on the achievement of the corporate funding goal, with the CGN Committee having the discretion to lower actual pay-outs to ensure that such awards are consistent with those granted to other plan participants. The 2006 target percentages of base salary for our named executive officers are as follows: Thomas F. Farrell, II 110%; Thomas N. Chewning 90%; Mark F. McGettrick and Jay L. Johnson 80%; and David A. Christian 70%.

(4) On March 31, 2006, the CGN Committee approved a long-term compensation award for our officers, which consists of two components of equal value: a restricted stock grant and a performance grant. The restricted stock fully vests at the end of three years with dividends paid during the restricted period at the same rate declared by Dominion for all shareholders. The restricted stock award also provides for pro-rata vesting if an officer dies, become disabled, retires, is terminated without cause or if there is a Change in Control.

The performance grant will be paid in cash in 2008 and can range from 0% to 200% of the target award. The amount earned by our officers will depend on the level of achievement of two equally weighted metrics: 1) Dominion s total shareholder return (TSR) for the twenty-one month period ended December 31, 2007 relative to the TSR of a group of industry peers selected by the CGN Committee; and 2) Dominion s return on invested capital (ROIC) for the two-year period ended December 31, 2007. The payout for TSR performance can range from 0% to 200% of the target award and will be interpolated between the following levels:

Relative TSR Performance	**Percentage Payout**
Top Quartile 75 to 100%	150% to 200%
2nd Quartile 50% to 74.9%	100%
3rd Quartile 25% to 49.9%	50% to 99.9%
4th Quartile below 25%	0%

Payout for ROIC performance will range from 0% to 200% of the target award and will be interpolated between the ranges established by the CGN Committee. The performance grant also provides for some form of pro-rata payout in the event an officer retires, dies, becomes disabled, or is terminated without cause. In the event of a Change in Control, payout will accelerate and be equal to the greater of the target amount or the payout amount that would be made for Dominion s goal performance based on Dominion s financial statements as of the day before the Change in Control. See CD&A on page 54 for the definition of a Change in Control.

(5) On December 19, 2006, the CGN Committee approved a restricted stock grant to Mr. Christian in order to secure and retain his services. The restricted stock fully vests at the end of three years with dividends paid during the restricted period at the same rate declared by Dominion for all shareholders. The restricted stock award also provides for pro-rata vesting if an officer dies, becomes disabled, or if there is a Change in Control. The fair market value for the December 20, 2006 restricted stock grant was $82.65 per share and was determined by taking the average of the high and low prices of Dominion stock on December 19, 2006 (grant approval date).

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OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END[1]

	Option Awards			Stock Awards	
Name	Number of Securities Underlying Unexercised Options Exercisable[2]	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested[3]
Thomas F. Farrell, II	70,000	$ 59.96	1/1/2008	14,651(4)	$ 1,228,340
	70,000	$ 59.96	1/1/2009	15,703(5)	$ 1,316,548
	70,000	$ 59.96	1/1/2010	15,101(6)	$ 1,266,106
Thomas N. Chewning	30,000	$ 59.96	1/1/2008	9,070(4)	$ 760,420
	45,000	$ 59.96	1/1/2009	8,153(5)	$ 683,556
	45,000	$ 59.96	1/1/2010	4,315(6)	$ 361,761
Mark F. McGettrick	16,667	$ 59.96	1/1/2009	5,349(4)	$ 448,460
	16,667	$ 59.96	1/1/2010	4,808(5)	$ 403,103
				4,315(6)	$ 361,770
Jay L. Johnson	17,000	$ 59.96	1/1/2008	5,456(4)	$ 457,429
	17,000	$ 59.96	1/1/2009	4,904(5)	$ 411,165
	17,000	$ 59.96	1/1/2010	3,301(6)	$ 276,775
David A. Christian				3,349(4)	$ 280,772
				2,951(7)	$ 247,382
				2,104(6)	$ 176,378
				1,089(8)	$ 91,302

(1) The executive officers included in this table may perform services for more than one subsidiary of Dominion. The amounts listed in the table reflect only that portion allocated to the Company.
(2) All options presented in this table are fully vested and exercisable. There are no unexercisable options outstanding.
(3) Based on closing stock price of $83.84 on December 29, 2006 which was the last day of the fiscal year on which Dominion stock was traded.
(4) Shares vest on February 24, 2008.
(5) 50% of shares vest on May 11, 2007 based on achievement of certain performance criteria; the remaining shares vest on May 11, 2009.
(6) Shares vest on April 1, 2009.
(7) 50% of shares vested on February 18, 2007 based on achievement of certain performance criteria; the remaining shares vest on February 18, 2009.
(8) Shares vest on December 20, 2009.

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OPTION EXERCISES AND STOCK VESTED

	Option Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise
Thomas N. Chewning[1]	15,000	$ 295,007

(1) Mr. Chewning s options were exercised pursuant to a Rule 10b5-1 trading plan. Mr. Chewning performs services for more than one subsidiary of Dominion and the amounts listed in the table reflect only that portion allocated to the Company.

PENSION BENEFITS[1,2]

No payments were made to any of the Named Executive Officers during Fiscal Year 2006 under any of the plans listed in this table.

Name	Plan Name	Number of Years Credited Service[3]	Present Value of Accumulated Benefit[1]
Thomas F. Farrell, II	Qualified Pension Plan	11.00	$ 71,152
	Benefit Restoration Plan Pre-2005	9.00	140,059
	Supplemental Retirement Plan Pre-2005	9.00	1,415,960
	New Benefit Restoration Plan	19.64	651,509
	New Supplemental Retirement Plan	19.64	1,588,116
Thomas N. Chewning	Qualified Pension Plan	19.00	182,829
	Benefit Restoration Plan Pre-2005	25.00	921,026
	Supplemental Retirement Plan Pre-2005	25.00	1,192,530
	New Benefit Restoration Plan	30.00	189,394
	New Supplemental Retirement Plan	30.00	227,659
Mark F. McGettrick	Qualified Pension Plan	22.50	171,449
	Benefit Restoration Plan Pre-2005	20.50	120,404
	Supplemental Retirement Plan Pre-2005	20.50	173,128
	New Benefit Restoration Plan	27.30	813,948
	New Supplemental Retirement Plan	27.30	696,417
Jay L. Johnson	Qualified Pension Plan	6.33	99,885
	Benefit Restoration Plan Pre-2005	4.33	61,303
	Supplemental Retirement Plan Pre-2005	4.33	568,243