VIRGINIA ELECTRIC & POWER CO
Form 10-K
February 28, 2008
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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, 2007

OR

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

Commission File Number 001-02255

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, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x Smaller reporting company ¨

(Do not check if a smaller

reporting company)

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

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

As of February 1, 2008, 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).

As of December 31, 2007, we had approximately 7,100 full-time employees. Approximately 3,300 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

Prior to a fourth quarter 2007 segment realignment, we managed our daily operations through three primary operating segments: Delivery, Energy and Generation. During the fourth quarter of 2007, we realigned our business units and began managing our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. We also report a Corporate and Other segment that includes our corporate and other functions. While we manage our daily operations through our operating segments 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 in Item 8. Financial Statements and Supplementary Data. For additional information on operating revenue related to our principal products and services, see Note 5 to our Consolidated Financial Statements.

DVP

DVP includes our regulated electric transmission, distribution and customer service operations. Our electric transmission and distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina. As of December 31, 2007, DVP served approximately 2.4 million retail customer accounts, including governmental agencies, as well as, wholesale customers such as rural electric cooperatives and municipalities. Revenue provided by our electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Actual revenues are

driven primarily by weather, customer growth and usage per customer. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. As part of this continued focus, we have implemented an asset management process to ensure that we are optimizing our investments to balance cost, performance and risk. We are also using technology to enhance customer service options. As we move toward the future, safety, operational performance and customer relationships will remain as key focal areas.

Revenue provided by our electric transmission operations is based primarily on rates approved by the Federal Energy Regulatory Commission (FERC). The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures. We are a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO) and our electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to the North American Electric Reliability Corporation (NERC) by the Energy Policy Act of 2005 (EPACT), we are committed to meeting NERC standards, modernizing our infrastructure and maintaining superior system reliability. We will continue to focus on safety, operational performance and execution of PJM s Regional Transmission Expansion Plan (RTEP) as we move toward the future.

Competition

Within DVP s service territory in Virginia and North Carolina, there is no competition for electric distribution service. Additionally, since our electric transmission facilities are integrated into PJM, our electric transmission services are administered by PJM and are not subject to competition in relation to transmission service provided to customers within the PJM region. In our transmission and distribution operations, we are seeing continued strong growth in new customers and increased usage per customer on a weather-normalized basis. Growth is particularly strong in the major metropolitan areas of Virginia. The combination of higher energy usage and efficient operations and maintenance spending has been critical to our performance. Operationally, we continue to enhance the customer experience through solid reliability performance and by completing the automation of all of our electric residential meters.

Regulation

DVP 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 North Carolina Utilities Commission (North Carolina Commission). See *Regulation State Regulations* for additional information. DVP s electric transmission rates, tariffs and terms of service are subject to regulation by FERC. Electric transmission siting authority remains the jurisdiction of the Virginia and North Carolina Commissions. However, EPACT provides FERC with certain backstop authority for transmission siting. See *State Regulations* and *Federal Regulations* in *Regulation* for additional information.

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Properties

DVP 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 DVP s 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 own and maintain these electric transmission facilities, they are a part of PJM, which coordinates the planning, operation, emergency assistance, and exchange of capacity and energy for such facilities.

Each year, as part of PJM s 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 northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. This project is estimated to cost approximately $243 million and is expected to be completed by June 2011. The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia. This project is estimated to cost approximately $180 million and is expected to be completed in June 2011. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals.

In addition, DVP 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

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

Seasonality

DVP s earnings 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.

Generation

Generation includes our portfolio of electric generation facilities, power purchase agreements and our energy supply operations. Our generation mix is diversified and includes coal, nuclear, gas, oil, renewables 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. As discussed in *Properties*, we have plans to add additional generation capacity to satisfy future growth in demand.

Generation s earnings primarily result from the generation and sale of electricity. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load are based on capped rates through 2008. Additionally, fuel costs, including purchased power, were subject to fixed-rate recovery provisions until July 1, 2007. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were instituted beginning July 1, 2007 for our Virginia jurisdictional customers. As discussed in *Status of Electric Regulation in Virginia* under *Regulation*, the Virginia General Assembly enacted legislation in April 2007 that returned the Virginia jurisdiction of our generation operations to a modified cost-of-service rate model, subject to rate caps in effect through December 31, 2008. During the remainder of the capped rate period, changes in our operating costs relative to costs used to establish capped rates, will likely impact our earnings.

Variability in earnings also results from changes in demand, which is primarily dependent on the weather, the cost of labor and benefits and the timing, duration and costs of outages.

Competition

Retail choice has been available to our Virginia jurisdictional electric customers since January 1, 2003; however, to date, competition in Virginia has not developed to any significant extent. In April 2007, the Virginia General Assembly passed legislation ending retail choice for most of our Virginia jurisdictional electric utility customers, effective January 1, 2009. 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, North Carolina Commission, FERC, Nuclear Regulatory Commission (NRC), Environmental Protection Agency (EPA), Department of Energy (DOE), 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 in our utility service area, we will need additional generation capacity over the next ten years. We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market in Virginia. As part of this program, the following projects are in various stages of development:

In April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 megawatt (Mw) natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. The Virginia Commission approved the application in August 2007, and construction has commenced. In December 2007, we received approval from the North Carolina

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Commission for a related affiliate transaction. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million.

In November 2007, we filed an application with the Virginia Commission for approval to add a fifth combustion turbine (Unit 5) at Ladysmith, at an estimated cost of $79 million.

In July 2007, we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon-capture compatible, clean-coal powered electric generation facility (Virginia City Hybrid Energy Center) to be located in Wise County, Virginia. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs including a return on common equity of 11.75% together with a 200-basis point enhancement through a rate adjustment clause. An evidentiary hearing was held in February 2008. An application for a permit to construct and operate the Virginia City Hybrid Energy Center, in compliance with federal and state air pollution laws, was filed in July 2006 with the Virginia Department of Environmental Quality. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated capital cost of approximately $1.8 billion.

Also in February 2008, we announced the proposed conversion of our Bremo power station (Bremo) from coal to natural gas as part of our plan to build the Virginia City Hybrid Energy Center. The proposal is contingent upon the Virginia Hybrid Energy Center entering service and receiving approvals from the Virginia Commission and Virginia Department of Environmental Quality. This proposed conversion project is part of our overall effort to reduce air emissions. Subject to applicable regulatory approvals, the conversion would occur within two years of the Virginia City Hybrid Energy Center entering service.

We are considering the construction of a third nuclear unit within the next 20 years at a site located at the North Anna power station (North Anna), which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) for the North Anna site. Also in November 2007, we along with ODEC, filed an application with the NRC for a Combined Construction Permit and Operating License (COL), which would allow us to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted our application for the COL and deemed it complete. Dominion has a cooperative agreement with the DOE to share equally the cost of the COL. We have not yet committed to building a new unit.

In December 2007, we announced an agreement to purchase a power station development project in Buckingham County, Virginia that will generate about 600 Mw. The project already has air and water permits for a combined-cycle, natural gas-fired power station; however such permits may need to be modified. In addition, construction of the project is subject to approval by the Virginia Commission, including approval under state regulations relating to bidding for the purchase of electric capacity and energy from other power suppliers, and the receipt of other environmental permits. A gas pipeline will also be required to be constructed to provide gas supply to the power station. Pending a closing under the purchase agreement and the receipt of

regulatory approval, we plan to build a combined cycle unit with operations expected to begin in summer 2011.

Sources of Energy Supply

Generation uses a variety of fuels to power our electric generation including procuring purchased power for system load requirements, as described below. Generation 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:

	2007 Source	2006 Source	2005 Source
Nuclear(1)	**29%**	31%	31%
Coal(2)	**35**	38	37
Oil	**2**	1	4
Purchased power, net	**28**	26	22
Natural gas(3)	**6**	4	5
Other			1

Total[4]	**100%**	100%	100%

(1) Excludes ODEC s 11.6% ownership interest in North Anna.
(2) Excludes ODEC s 50% ownership interest in the Clover Power Station. The average cost of coal for 2007 Virginia in-system generation was $27.80 per megawatt hour.
(3) Includes natural gas used in combustion turbines that are fueled by gas.
(4) Excludes off-system sales.

Nuclear Fuel Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A). 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 for the near term. 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.

Purchased Power Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for system load requirements.

Seasonality

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

NUCLEAR DECOMMISSIONING

Generation has a total of four licensed, operating nuclear reactors at its Surry power station (Surry) and at North Anna, both in Virginia, that serve our customers. We have decommissioning obligations for each of these power stations, as discussed in Note 13 to our Consolidated Financial Statements. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station 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 $1.9 billion in 2007 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. The license expiration dates for our units are shown in the following table:

	Surry		North Anna		
	Unit 1	Unit 2	Unit 1	Unit 2	Total
(dollars in millions)					
NRC license expiration year	**2032**	**2033**	**2038**	**2040**	
Most recent cost estimate (2007 dollars)	**$ 471**	**$ 499**	**$ 449**	**$ 471**	**$ 1,890**
Funds in trusts at December 31, 2007	**374**	**369**	**306**	**290**	**1,339**
2007 contributions to trusts	**1.4**	**1.5**	**1.0**	**0.9**	**4.8**

Corporate and Other

We also have a Corporate and Other segment that includes our corporate and other functions, and specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

Environmental Strategy

We are committed to being a good environmental steward. Our ongoing objective is to provide reliable, affordable energy for our customers while being environmentally responsible. Our integrated strategy to meet this objective consists of four major elements:

- Conservation and efficiency;
- Renewable generation development;
- Other generation development to maintain our fuel diversity, including clean coal, advanced nuclear energy, and natural gas; and
- Improvements in other energy infrastructure.

Conservation plays a critical role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides for incentives for energy conservation and sets a goal to reduce electricity consumption by retail customers in 2022 by ten percent of the amount consumed in 2006 through the implementation of conservation programs. We announced plans in September 2007 for a series of pilot programs focused on energy conservation and demand response.

The pilots will be offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results are representative, customers will not be able to volunteer for the pilots nor participate in more than one pilot. We will report results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness.

The pilots approved by the Virginia Commission include:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots are designed to cycle central heating and air conditioning units during peak-energy demand times, inform customers about their real-time energy consumption patterns, promote programmable thermostats that allow customers to control their use of electricity, and educate customers about the value of reducing energy use during peak-use times.

Free energy audits and energy efficiency kits to 150 existing residential customers, 100 new homes meeting energy efficiency guidelines set by the EPA, and 50 small commercial customers. In addition, 250 new homes will receive energy efficiency welcome kits that include compact fluorescent light bulbs.

Incentives for commercial customers to reduce load during periods of peak demand by running their generators to produce up to 100 Mw of electricity. This would be in addition to existing Dominion options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting goals for renewable power. We are committed to meeting Virginia s goal of 12% renewable power by 2022 and North Carolina s renewable portfolio standard of 12.5% by 2021.

We are actively assessing development opportunities in our service territories for renewable technologies. In November, 2007 we issued a request for proposals (RFP) for renewable energy projects in Virginia, North Carolina or elsewhere in the PJM Interconnect region. The RFP seeks the purchase of renewable energy generation projects, as well as renewable energy credits. Generation currently provides approximately two percent of its generation from renewable sources. We also anticipate using up to 20% biomass (woodwaste) at the proposed Virginia City Hybrid Energy Center discussed in *Generation-Properties*.

We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market of Virginia. The new generation planned in connection with this program is discussed further under *Generation-Properties*. We expect that these investments collectively will provide the following benefits: expanded electricity production capability; increased technological and fuel diversity; and a reduction in the carbon dioxide (CO_2) emissions intensity of our generation fleet. A critical aspect of the *Powering Virginia* program is the extent to which we seek to reduce the carbon intensity of our generation fleet by developing generation facilities with zero CO_2 and low CO_2 emissions, as well as economically viable facilities that can be equipped for CO_2 separation and sequestration. There is no current technological solution

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to retro-fit existing fossil-fueled technology to capture greenhouse gas emissions. Given that new generation units have useful lives of up to 50 years, we will give full consideration to CO_2 and other greenhouse gas emissions when making long-term investment decisions.

Finally, we plan to make a significant investment in improving the capabilities and reliability of our electric transmission and distribution system. These enhancements are primarily aimed at meeting our continued goal of providing reliable service. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed or to be developed in the future.

Regulation

We are subject to regulation by the Virginia Commission, North Carolina Commission, Securities and Exchange Commission (SEC), FERC, EPA, DOE, NRC, 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.

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;

after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and

shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or

may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.

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 and energy efficiency, conservation and renewable energy programs; and

Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

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

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established ROE. We are unable to predict the outcome of future rate actions at this time, however an unfavorable outcome could adversely affect our results of operations.

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Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices have increased considerably since 2004, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were re-instituted beginning July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted, this mechanism ensures dollar for dollar recovery for prudently incurred fuel costs.

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

North Carolina Regulation

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 annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to change under annual fuel cost adjustment proceedings.

Federal Regulations

Federal Energy Regulatory Commission

Under the Federal Power Act, FERC regulates PJM wholesale sales and transmission of electricity in interstate commerce by public utilities. We sell electricity in the PJM 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. In May 2005, FERC issued an order finding that PJM s existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings on the matter. In January 2008, FERC affirmed its earlier decision that the PJM transmission rate design for existing facilities had not become unjust and unreasonable. For recovery of costs of investments of

new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a regional rate design where all customers pay a uniform rate based on the costs of such investment. For recovery of costs of investment in new PJM-planned transmission facilities that operate below 500kV, FERC affirmed its earlier decision to allocate costs on a beneficiary pays approach. A notice of appeal of this decision was filed in February 2008 at the United States Court of Appeals for the Seventh Circuit. We cannot predict the outcome of the appeal.

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 NERC as the ERO beginning on January 1, 2007. In late 2006, FERC also issued an initial order approving many reliability standards, that went into effect on January 1, 2007. Beginning on June 4, 2007, entities that violate standards will be subject to fines of between $1 thousand and $1 million per day, and can also be assessed with non-monetary penalties, 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 the expenditures to be significant.

Environmental Regulations

Each of our operating segments faces substantial laws, regulations and compliance costs with respect to environmental matters. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. If our expenditures for pollution control technologies and associated operating costs are not recoverable from customers through regulated rates, those costs could adversely affect future results of operations and cash flows. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Company. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance, see *Environmental Matters* in *Future Issues and Other Matters* in MD&A. Additional information can also be found in Item 3. Legal Proceedings and Note 21 to our Consolidated Financial Statements.

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, nitrogen oxide 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 February 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates CAMR as promulgated by the EPA. At this time we cannot determine if this ruling will be subject to further appeals and how the EPA, and subsequently the states, may alter their approach to reducing mercury emissions. We also cannot estimate at this time the impact that this ruling will have on our future capital expenditures.

Based on the increasing intensity of national and international studies regarding climate change and its relationship to greenhouse gas emissions, we expect that there may be federal legislative or regulatory action in this area in the near future. The outcome in terms of specific requirements and timing is uncertain but may include a greenhouse gas emissions cap-and-trade program or carbon tax for electric generators. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate greenhouse gas emissions which could result in future EPA action. In June 2007, the President announced U.S. support for an effort to develop a new post-2012 framework on climate change involving the top ten to fifteen greenhouse gas emitting countries that would focus on establishing a long-term global goal to reduce greenhouse gas emissions with each country establishing its own mid-term targets and programs. At the state level, the Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025. The Governor has formed a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of specific requirements, timing and cost of compliance is uncertain.

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 under CWA Section 316b 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 and winter storms, can be destructive, causing outages and property damage that require us to incur additional expenses. In addition, droughts can result in reduced water-levels that could adversely affect operations at some of our power stations.

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, the revision or reinterpretation of existing laws or regulations, or penalties imposed for non-compliance with existing laws or regulations may require us to incur additional expenses.

We could be subject to penalties as a result of mandatory reliability standards. As a result of EPACT, owners and operators of bulk power transmission systems, including the Company, are subject to mandatory reliability standards enacted by NERC and enforced by FERC. If we are found not to be in compliance with the mandatory reliability standards we could be subject to sanctions, including substantial monetary penalties.

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Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could adversely affect our cash flow and profitability. Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward permitting, emission fees, environmental monitoring, installation and operation of pollution control equipment and purchase of allowances and/or offsets. Additionally, we could be responsible for expenses relating to remediation and containment obligations, including at sites where we have been identified by a regulatory agency as a PRP. Our expenditures relating to environmental compliance have been significant in the past, and we expect that they will remain significant in the future. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs with certainty due to our inability to predict the requirements and timing of implementation of any new environmental rules or regulations related to emissions. Other factors which affect our ability to predict our future environmental expenditures with certainty include the difficulty in estimating clean-up costs and quantifying liabilities under environmental laws that impose joint and several liability on all responsible parties.

If federal and/or state requirements are imposed on energy companies mandating further emission reductions, including limitations on carbon dioxide emissions, such requirements could make some of our electric generating units uneconomical to maintain or operate. Environmental advocacy groups, other organizations and some agencies are focusing considerable attention on carbon dioxide emissions from power generation facilities and their potential role in climate change. We expect that federal legislation, and possibly additional state legislation, may pass resulting in the imposition of limitations on greenhouse gas emissions from fossil fuel-fired electric generating units. Such limits could make certain of our electric generating units uneconomical to operate in the long term, unless there are significant improvements in the commercial availability and cost of carbon capture and sequestration technology. In addition, a number of bills have been introduced in Congress that would require greenhouse gas emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. Compliance with these greenhouse gas emission reduction requirements may require us to commit significant capital toward carbon capture and sequestration technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high emitting generation and replacement with lower emitting generation. The costs of compliance with expected greenhouse gas legislation are subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and sequestration technology and associated regulations, and our selected compliance alternatives. As a result, we

cannot estimate the effect of any such legislation on our results of operations, financial condition, or our customers.

We are exposed to cost-recovery shortfalls because of capped base rates in effect in Virginia. Under the Restructuring Act, as amended in 2004 and 2007, our base rates remain capped through December 31, 2008. Although the Restructuring Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls, such as costs related to hurricanes or other unanticipated events.

Our base rates are subject to regulatory review. As a result of the Restructuring Act, commencing in 2009, our base rates will be reviewed by the Virginia Commission under a modified cost-of-service model. Such rates will be set based on analyses of our costs and capital structures, as reviewed and approved in regulatory proceedings. Under the Restructuring Act, the Virginia Commission may, in a proceeding conducted in 2009, reduce rates or order a credit to customers if we are deemed to have earnings during a 2008 test period which are more than 50 basis points above a return on equity level to be established by the Virginia Commission in that proceeding. After the initial rate case, the Virginia Commission will review our rates biennially and may order a credit to customers if we are deemed to have earned more than 50 basis points above a return on equity level established by the Virginia Commission and may reduce rates if we are found to have had earnings in excess of the established return on equity level during two consecutive biennial review periods.

Energy conservation could negatively impact our financial results. A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption by certain dates. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, it could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that resulted in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We are unable to determine what impact, if any, conservation will have on our financial condition or results of operations.

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 our 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 decommissioning costs could exceed the amounts in our trusts or 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, swaps, forwards, options and financial transmission rights to manage the commodity and financial market risks of our business operations. 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

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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.

We may not complete plant construction or expansion projects that we commence, or we may complete projects on materially different terms or timing than initially anticipated and we may not be able to achieve the intended benefits of any such project, if completed. We have announced plant construction and expansion projects and may consider additional plant construction and expansion projects in the future. We anticipate that we will be required to seek additional financing in the future to fund our current and future plant construction and expansion projects and we may not be able to secure such financing on favorable terms. In addition, we may not be able to complete the plant construction or expansion projects on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners or other factors beyond our control. Even if plant construction and expansion projects are completed, the total costs of the plant construction and expansion projects may be higher than anticipated and the performance of our business following the plant construction and expansion projects may not meet expectations. Additionally, regulators may disallow recovery of some of the costs of a plant or expansion project if they are deemed not to be prudently incurred. Further, we may not be able to timely and effectively integrate the plant construction and expansion projects into our operations, such integration may result in unforeseen operating difficulties or unanticipated costs. Any of these or other factors could adversely affect our ability to realize the anticipated benefits from the plant construction and expansion projects.

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, 2008, our senior unsecured debt is rated A-, stable outlook, by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc. (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 any of our First and Refunding Mortgage Bonds. Although there are no publicly issued bonds outstanding as of December 31, 2007, we may issue additional bonds in the future.

We share our principal office in Richmond, Virginia, which is owned by our parent company, Dominion. In addition, our DVP 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, 2007:

Power Generation

Plant	Location	Primary Fuel Type	Net Summer Capability (Mw)
North Anna	Mineral, VA	Nuclear	1,596(a)
Surry	Surry, VA	Nuclear	1,598
Mt. Storm	Mt. Storm, WV	Coal	1,560
Chesterfield	Chester, VA	Coal	1,253
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
Polyester(c)	Hopewell, 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	186
Darbytown (CT)	Richmond, VA	Oil	156
Chesapeake (CT)	Chesapeake, VA	Oil	115
Possum Point (CT)	Dumfries, VA	Oil	72
Northern Neck (CT)	Lively, VA	Oil	47
Low Moor (CT)	Covington, VA	Oil	48
Kitty Hawk (CT)	Kitty Hawk, NC	Oil	32
Remington (CT)	Remington, VA	Gas	582
Possum Point (CC)	Dumfries, VA	Gas	532
Chesterfield (CC)	Chester, VA	Gas	397
Possum Point	Dumfries, VA	Gas	312
Elizabeth River (CT)	Chesapeake, VA	Gas	300
Ladysmith (CT)	Ladysmith, VA	Gas	297
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	158
Darbytown (CT)	Richmond, VA	Gas	156
Bath County	Warm Springs, VA	Hydro	1,706(d)
Gaston	Roanoke Rapids, NC	Hydro	225
Roanoke Rapids	Roanoke Rapids, NC	Hydro	99
Pittsylvania	Hurt, VA	Biomass	83
Other	Various	Various	15
			15,723
Power Purchase Agreements			2,076
		Total Capacity	**17,799**

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

(a) Excludes 11.6% undivided interest owned by Old Dominion Electric Cooperative (ODEC).
(b) Excludes 50% undivided interest owned by ODEC.
(c) Previously referred to as Hopewell.
(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. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations.

See *DVP, Generation* and *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 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)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
2007	**$ 77**	**$ 65**	**$ 196**	**$ 39**	**$ 377**
2006	76	63	134	76	349

Item 6. Selected Financial Data

Year Ended December 31, (millions)	**2007**	2006	2005(1)	2004(2)	2003(3)
Operating revenue	**$ 6,181**	$ 5,603	$ 5,712	$ 5,371	$ 5,191
Income from continuing operations before extraordinary item and cumulative effect of changes in accounting principles	**606**	478	485	590	556
Income (loss) from discontinued operations, net of tax(4)			(471)	(159)	26
Extraordinary item, net of tax(5)	**(158)**				
Cumulative effect of changes in accounting principles, net of tax			(4)		(21)
Net income	**448**	478	10	431	561
Balance available for common stock	**432**	462	(6)	415	546
Total assets	**17,057**	15,683	15,449	17,318	16,884
Long-term debt	**5,316**	3,619	3,888	4,958	4,744

(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 (SFAS) 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) The reapplication of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to the Virginia jurisdiction of our generation operations resulted in a $158 million after-tax extraordinary charge. See Note 2 to our Consolidated Financial Statements.

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

Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses the results of operations and general financial condition of Virginia Electric and Power Company. MD&A should be read in conjunction with our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. The terms Virginia Power, Company, we, our and us are used througho 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 or more 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. All of our common stock is owned by our parent company, 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, shoulc 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 and changes to environmental and other laws and regulations, including those related to climate change, to which we are subject;
- Cost of environmental compliance, including those costs related to climate change;
- Risks associated with the operation of nuclear facilities;

- Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;
- Changes in federal and state tax laws and regulations;
- 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 the effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- The inability to complete planned construction projects within the terms and time frames initially anticipated;
- Changes in rules for regional transmission organizations (RTOs) in which we participate, including changes in rate designs and new and evolving capacity models; 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 regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. We serve approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities.

Prior to a fourth quarter segment realignment, we managed our daily operations through three primary operating segments: Delivery, Energy and Generation. During the fourth quarter of 2007, we realigned our business units and began managing our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. We also report a Corporate and Other segment that includes our corporate and other functions. While we manage our daily operations through our operating segments, our assets remain wholly-owned by us and our legal subsidiaries.

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 and Other segment.

DVP includes our regulated electric transmission and distribution operations in Virginia and northeastern North Carolina,

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

as well as our customer service operations. Our electric transmission and distribution operations serve residential, commercial, industrial and governmental customers.

Revenue provided by electric transmission operations is based primarily on rates approved by the Federal Energy Regulatory Commission (FERC). The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability results from changes in rates, the demand for services, which is primarily weather dependent, and operating and maintenance expenditures. We are a member of PJM Interconnection, LLC (PJM), an RTO, and our electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to the North American Electric Reliability Corporation (NERC) by the Energy Policy Act of 2005, we are committed to meeting NERC standards, modernizing our infrastructure and maintaining superior system reliability. We will continue to focus on safety, operational performance and execution of PJM s Regional Transmission Expansion Plan (RTEP) as we move toward the future.

Revenue provided by electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Actual revenues are driven primarily by weather, customer growth and usage per customer. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link capital investments to operational results. As part of this continued focus, we have implemented an asset management process to ensure that we are optimizing our investments to balance cost, performance and risk. We are also using technology to enhance customer service options. As we move toward the future, safety, operational performance and customer relationships will remain as key focal areas.

In our transmission and distribution operations, we are seeing continued strong growth in new customers and increased usage per customer on a weather-normalized basis. Growth is particularly strong in the major metropolitan areas of Virginia. The combination of higher energy usage and efficient operations and maintenance spending has been critical to our performance. Operationally, we continue to enhance the customer experience through solid reliability performance and by completing the automation of all of our electric residential meters.

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, renewables 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.

Generation s earnings primarily result from the generation and sale of electricity. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load are based on capped rates through 2008. Additionally, fuel costs, including purchased power, were subject to fixed rate recovery provisions until July 1, 2007. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were instituted

beginning July 1, 2007 for our Virginia jurisdictional customers. As discussed in *Status of Electric Regulation in Virginia* under *Future Issues and Other Matters*, the Virginia General Assembly enacted legislation in April 2007 that returned the Virginia jurisdiction of our generation operations to a modified cost-of-service rate model, subject to rate caps in effect through December 31, 2008. During the remainder of the capped rate period, changes in our utility operating costs relative to costs used to establish capped rates, will likely impact our earnings. Variability in earnings also results from changes in demand, which is primarily dependent on the weather, the cost of labor and benefits and the timing, duration and costs of outages.

Corporate and Other includes our corporate and other functions, and specific items attributable to our primary operating segments that are not included in profit measures evaluated by executive management, in assessing the segments performance or 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, which also serves as our Audit Committee.

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 or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulator.

As discussed further in Note 2 to our Consolidated Financial Statements, in April 2007, the Virginia General Assembly passed legislation that returns the Virginia jurisdiction of our utility generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to those operations on April 4, 2007, the date the legislation was enacted. The reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195 million ($119 million after tax) of unrealized gains from accumulated other comprehensive income (AOCI) related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*. In connection with the reapplication of SFAS No. 71, we prospectively changed certain of our accounting policies for the Virginia jurisdiction of our generation operations to those used by cost-of-service rate-regulated entities. Other than the extraordinary item previously discussed, the overall impact of these changes was not material to our results of operations or financial condition in 2007.

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.

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 2007, 2006 and 2005, we recognized $38 million, $40 million and $44 million, respectively, of accretion and expect to incur $38 million in 2008. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, we began recording accretion and depreciation associated with nuclear decommissioning AROs, formerly charged to expense, as an adjustment to the regulatory liability for nuclear decommissioning trust funds previously discussed, in order to match the recognition for rate-making purposes.

A significant portion of our AROs relates to the future decommissioning of our nuclear facilities. At December 31, 2007, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $637 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 utilize 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. The use of alternative rates could have been material to the liabilities recognized. For example, had we increased the cost escalation rate by 0.5%, the amount recognized as of December 31, 2007, for our AROs, related to nuclear decommissioning would have been $117 million higher.

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 $270 million and $233 million of accrued unbilled revenue at December 31, 2007 and 2006, respectively.

The calculation of unbilled revenues is complex and includes numerous estimates and assumptions including historical usage,

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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 the laws 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.

Prior to 2007, we established liabilities for tax-related contingencies when we believed that it was probable that a liability had been incurred and the amount could be reasonably estimated in accordance with SFAS No. 5, *Accounting for Contingencies*, and subsequently reviewed them in light of changing facts and circumstances. However, as discussed in Note 3 to our Consolidated Financial Statements, effective January 1, 2007, we adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). 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 tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position that is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. At December 31, 2007, we had $195 million of unrecognized tax benefits. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

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. 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. At December 31, 2007, we had no valuation allowances on our deferred tax assets.

Accounting Standards

During 2007, 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)	**2007**	**$ Change**	2006	$ Change	2005
Net Income	**$ 448**	**$ (30)**	$ 478	$ 468	$ 10

Overview

2007 vs. 2006

Net income decreased by 6% to $448 million. Unfavorable drivers include an extraordinary charge in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, an increase in outage costs primarily due to an increase in the number of scheduled outage days at certain of our electric generating facilities and a decrease in gains from sales of emissions allowances. Favorable drivers include an increase in regulated electric sales resulting from favorable weather, customer growth and other factors, and lower fuel expense due to the reinstatement of annual fuel rate adjustments, effective July 1, 2007, for the Virginia jurisdiction of our generation operations, with deferred fuel accounting for over- or under-recoveries of fuel costs.

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.

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Analysis of Consolidated Operations

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

Year Ended December 31, (millions)	2007	$ Change	2006	$ Change	2005
Operating Revenue	$ 6,181	$ 578	$ 5,603	$ (109)	$ 5,712
Operating Expenses					
Electric fuel and energy purchases	2,478	94	2,384	(169)	2,553
Purchased electric capacity	429	(24)	453	(24)	477
Other energy-related commodity purchases	27	(29)	56	22	34
Other operations and maintenance	1,280	252	1,028	83	945
Depreciation and amortization	568	32	536	9	527
Other taxes	173	10	163	(7)	170
Other income	55	(20)	75	5	70
Interest and related charges	304	8	296	(26)	322
Income tax expense	371	87	284	15	269
Extraordinary item, net of tax	(158)	(158)			
Loss from discontinued operations, net of tax				471	(471)

An analysis of our results of operations for 2007 compared to 2006 and 2006 compared to 2005 follows:

2007 vs. 2006

Operating Revenue increased 10% to $6.2 billion, reflecting the combined effects of:

- A $166 million increase due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
- A $162 million increase in sales to retail customers attributable to variations in rates resulting from changes in sales mix and other factors ($95 million) and new customer connections ($67 million) primarily in our residential and commercial customer classes;
- A $131 million increase in sales to retail customers due to an increase in the number of heating and cooling degree days. As compared to the prior year, we experienced a 15% increase in cooling degree days and a 10% increase in heating degree days;
- An $80 million increase in sales to wholesale customers; and
- A $42 million increase resulting primarily from higher ancillary service revenue reflecting higher regulation and operating reserves revenue received from PJM.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 4% to $2.5 billion. The underlying fuel costs, including those subject to

deferral accounting, increased by approximately $501 million due to higher consumption of fossil fuel and purchased power resulting from an increase in the number of heating and cooling degree days, higher commodity costs and a change in generation mix. This increase was largely offset by a $408 million decrease primarily due to the deferral of fuel expenses that were in excess of current period fuel rate recovery.

Purchased electric capacity expense decreased 5% to $429 million, primarily due to scheduled capacity reductions for certain long-term power purchase contracts.

Other energy-related commodity purchases expense decreased 52% to $27 million, primarily reflecting a decrease in nonutility coal activities that have been substantially exited.

Other operations and maintenance expense increased 25% to $1.3 billion, primarily reflecting:

A $74 million increase in outage costs related to scheduled outages at certain of our generating facilities;
A $54 million decrease in gains from the sale of emissions allowances held for consumption;
A $40 million increase due to higher salaries and wages ($42 million) and incentive-based compensation ($30 million), partially offset by a decrease in pension and other postretirement benefits expense ($32 million);
A $34 million increase related to services provided by Dominion Resources Services, Inc. (DRS), an affiliate that provides accounting, legal and certain administrative and technical services to us;
A $31 million increase primarily due to the inclusion of certain FTR proceeds in *Electric fuel and energy purchases expense* beginning July 1, 2007, as a result of the reapplication of deferred fuel accounting for the Virginia jurisdiction. These FTR proceeds are used to offset congestion costs associated with PJM spot market activity incurred by our generation operations; and
A $23 million increase related to outside services for tree trimming and brush removal and other expenses; partially offset by
A $16 million decrease in expenses for major storms and service restoration associated with our distribution operations.

Depreciation and amortization expense increased 6% to $568 million, due to incremental expense resulting from property additions, a change in depreciation rates for our generation assets to reflect the results of a new depreciation study and increased amortization expense associated with emissions allowances held for consumption.

Other taxes increased 6% to $173 million, primarily due to the recognition of increased property taxes in 2007, reflecting changes in tax rates and assessed valuations.

Other income decreased 27% to $55 million, resulting primarily from the recognition of decommissioning trust earnings as a regulatory liability due to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

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, including costs resulting from tropical storm Ernesto in September 2006;
- A $15 million increase resulting from higher salaries, wages, and pension and medical benefits expense;
- 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 DRS;
- 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 held for consumption; 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.

Outlook

We believe our operating businesses will provide stable growth in net income in 2008. The following are growth factors that will impact these expected results:

- A full year of deferred fuel accounting for Virginia jurisdiction fuel costs as compared to six months in 2007;
- A decrease in outage costs reflecting a decrease in the number of scheduled outage days at certain of our electric generating facilities; and
- Continued growth in utility customers.

The growth factors in 2008 are expected to be partially offset by:

- A potential decrease in regulated electric sales, as compared to 2007, assuming our utility service territory experiences a return to normal weather in 2008; and
- An increase in depreciation expense attributable to the implementation of revised depreciation rates for our generation assets resulting from a new depreciation study during the fourth quarter of 2007.

Segment Results of Operations

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

Year Ended December 31, (millions)	**2007**	**$ Change**	2006	$ Change	2005
DVP	**$ 342**	**$ 3**	$ 339	$ (25)	$ 364
Generation	**276**	**125**	151	(24)	175
Primary operating segments	**618**	**128**	490	(49)	539
Corporate and Other	**(170)**	**(158)**	(12)	517	(529)
Consolidated	**$ 448**	**$ (30)**	$ 478	$ 468	$ 10

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DVP

Presented below are operating statistics related to our DVP operations:

Year Ended December 31,	**2007**	**% Change**	2006	% Change	2005
Electricity delivered (million mwhrs)[1]	**84.7**	**6%**	79.8	(2)%	81.4
Degree days (electric service area):					
Cooling[2]	**1,794**	**15**	1,557	(9)	1,707
Heating[3]	**3,500**	**10**	3,178	(16)	3,784
Average electric delivery customer accounts[4]	**2,361**	**1**	2,327	2	2,286

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.

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

2007 vs. 2006

(millions)	**Increase (Decrease)**
Regulated electric sales:	
Weather	**$ 22**
Customer growth	**11**
Major storm damage and service restoration[1]	**9**
Reliability and outside services expenses	**(18)**
Salaries, wages and benefits expense	**(11)**
Other	**(10)**
Change in net income contribution	**$ 3**

(1) Primarily resulting from the absence in 2007 of expenses associated with tropical storm Ernesto in September 2006.

2006 vs. 2005

(millions)	Increase (Decrease)
Regulated electric sales:	
Weather	$ (34)
Customer growth	13
Major storm damage and service restoration[1]	(18)
2005 North Carolina rate case settlement	(6)
Interest expense	10
Other	10

Change in net income contribution	$	(25)

(1) Reflects an increase in major storm damage and service restoration expenses including expenses associated with tropical storm Ernesto in September 2006.

Generation

Presented below are operating statistics related to our Generation operations:

Year Ended December 31,	**2007**	**% Change**	2006	% Change	2005
Electricity supplied (million mwhrs)	**84.7**	**6%**	79.7	(2)%	81.4
Degree days (electric service area):					
Cooling	**1,794**	**15**	1,557	(9)	1,707
Heating	**3,500**	**10**	3,178	(16)	3,784

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

2007 vs. 2006

(millions)		**Increase (Decrease)**
Unrecovered Virginia fuel expenses[1]	**$**	**120**
Regulated electric sales:		
Weather		**37**
Customer growth		**20**
Ancillary service revenue		**27**
Outage costs[2]		**(45)**
Capacity expense		**13**
Sale of emissions allowances		**(34)**
Salaries, wages and benefits expense		**(17)**
Depreciation expense		**(18)**
Other		**22**
Change in net income contribution	**$**	**125**

(1) Primarily reflects the reapplication of deferred fuel accounting effective July 1, 2007. This benefit is partially offset by increased consumption of fossil fuel and higher purchased power costs during the first six months of 2007.
(2) Primarily reflects an increase in scheduled outage costs for certain nuclear and fossil units.

2006 vs. 2005

(millions)		Increase (Decrease)
Regulated electric sales:		
Weather	$	(64)
Customer growth		24
Energy supply margin[1]		(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		12
Change in net income contribution	$	(24)

(1) Primarily reflects a reduced benefit from FTRs in excess of congestion costs.

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

Corporate and Other

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

Year Ended December 31,	2007	2006	2005
(millions)			
VPEM discontinued operations	**$**	$	$ (471)
Specific items attributable to operating segments	**(166)**	(12)	(58)
Other	**(4)**		
Net expense	**$ (170)**	$ (12)	$ (529)

Specific Items Attributable To Operating Segments

Corporate and Other includes specific items attributable to our primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or 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 issuances of debt and/or equity securities.

At December 31, 2007, we had $2.0 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 is presented below:

Year Ended December 31,	2007	2006	2005
(millions)			
Cash and cash equivalents at beginning of year	**$ 18**	$ 54	$ 2
Cash flows provided by (used in):			
Operating activities	**1,216**	1,080	1,496
Investing activities	**(1,306)**	(960)	(800)
Financing activities	**121**	(156)	(644)
Net increase (decrease) in cash and cash equivalents	**31**	(36)	52
Cash and cash equivalents at end of year	**$ 49**	$ 18	$ 54

Operating Cash Flows

In 2007, net cash provided by operating activities increased by $136 million as compared to 2006, primarily due to a reduction in income taxes paid. We believe that our operations provide a stable source of cash flow 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, 2007, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral, however, we held no collateral for these transactions at December 31, 2007.

(millions)	Gross Credit Exposure
Investment grade[1]	**$ 13**
Non-investment grade[2]	**3**
No external ratings:	
Internally rated investment grade[3]	**16**
Internally rated non-investment grade	
Total	**$ 32**

(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, a division of the McGraw-Hill Companies, Inc. (Standard & Poor s). The five largest counterparty exposures, combined, for this category represented approximately 40% of the total gross credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented approximately 8% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 51% of the total gross credit exposure.

Investing Cash Flows

In 2007, net cash used in investing activities increased by $346 million as compared to 2006. This reflects an increase in capital expenditures and a reduction in proceeds from the sale of emissions allowances held for consumption.

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 the rules that currently govern the registration, communications and offering processes under the Securities Act of 1933. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. Under these 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.

In 2007, net cash provided by financing activities was $121 million as compared to net cash used in financing activities of $156 million in 2006. The change reflects a net increase in borrowings.

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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 with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and 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, 2007, total commercial paper outstanding supported by the joint credit facility was $757 million, of which our borrowings were $257 million, and the total amount of letter of credit issuances was $229 million of which less than $8 million were issued on our behalf, leaving approximately $2.0 billion available for issuance.

Long-Term Debt

During 2007, we issued the following long-term debt. The proceeds were used for general corporate purposes, including the repayment of short-term debt.

Type (millions)	Principal	Rate	Maturity
Senior notes	$ 600	6.00%	2037
Senior notes	600	5.95%	2017
Senior notes	600	5.10%	2012
Senior notes	450	6.35%	2037
Total long-term debt issued	$ 2,250		

In January 2008, we borrowed $30 million in connection with the Economic Development Authority of the City of Chesapeake Pollution Control Refunding Revenue Bonds, Series 2008 A, which mature in 2032 and bear a coupon rate of 3.6%. The proceeds were used to refund the principal amount of the Industrial Development Authority of the City of Chesapeake Money Market Municipals Pollution Control Revenue, Series 1985 that would otherwise have matured in February 2008.

In November 2007, we borrowed $14 million in connection with the Economic Development Authority of the County of Chesterfield s issuance of its Solid Waste and Sewage Disposal Revenue Bonds, Series 2007 A, which mature in 2031 and bear a coupon rate of 5.60%. The bonds were issued pursuant to a trust agreement whereby funds are withdrawn from the trust as improvements are made at our Chesterfield power station located in Chester, Virginia. We have withdrawn less than $1 million from the trust as of December 31, 2007.

During 2007, we repaid $1.3 billion of long-term debt securities.

Borrowings from Parent

We have the ability to borrow funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2007, our nonregulated subsidiaries had outstanding borrowings, net of repayments, under the Dominion money pool of $114 million. In December 2007, we recorded

contributed capital of $220 million reflecting the conversion of a $220 million note payable to Dominion to equity. There were no short-term or long-term demand note borrowings at December 31, 2007.

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, 2008 follow:

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

As of February 1, 2008, Fitch Ratings Ltd. (Fitch), Moody s and Standard & Poor s maintain a stable outlook for their ratings of our company.

In December 2007, Standard & Poor s raised its corporate credit rating on the Company to A- from BBB to reflect a lower risk profile. Standard & Poor s also affirmed the A-2 commercial paper rating.

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

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Management s Discussion and Analysis of Financial Condition and Results of Operations, Continued

holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to us. Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation, restrictions on disposition of all or substantially all of our assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- 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, 2007, 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 or any material subsidiaries of Dominion 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, 2007, 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, 2007, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion as of December 31, 2007.

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.

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, 2007. 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 our current liabilities will be paid in cash in 2008.

(millions)	2008	2009-2010	2011-2012	2013 and thereafter	Total
Long-term debt[1]	$ 286	$ 370	$ 631	$ 4,310	$ 5,597
Interest payments[2]	315	591	559	4,015	5,480
Leases	29	47	29	23	128
Purchase obligations[3]:					
Purchased electric capacity for utility operations	383	713	700	1,857	3,653
Fuel to be used for utility operations	794	814	566	435	2,609
Transportation and storage	20	31	20	28	99
Other	128	46	2		176
Other long-term liabilities[4]	4				4
Total cash payments	$ 1,959	$ 2,612	$ 2,507	$ 10,668	$ 17,746

(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. Due to uncertainty about the timing and amounts that will ultimately be paid, $144 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 6 to our Consolidated Financial Statements.

Planned Capital Expenditures

Our planned capital expenditures are expected to total approximately $2.2 billion, $2.8 billion and $2.6 billion in 2008, 2009 and 2010, respectively. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and capital contributions from Dominion. Our planned capital expenditures include capital projects that are subject to approval by regulators and our Board of Directors. Our annual capital expenditures for plant and equipment for 2008, including environmental upgrades and construction improvements, are expected to total approximately as follows:

- Generation and nuclear fuel: $1.4 billion;
- Transmission: $327 million; and
- Distribution: $463 million.

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation capacity in the future. See *Generation Expansion* in *Future Issues And Other Matters* for a discussion of our expansion plans.

We may choose to postpone or cancel certain planned capital expenditures in order to mitigate the need for future debt financings and equity issuances.

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Future Issues and Other Matters

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act and Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 31, 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- 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 and energy efficiency, conservation and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

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

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established ROE. We are unable to predict the outcome of future rate actions at this time, however an unfavorable outcome could adversely affect our results of operations.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices have increased considerably since 2004, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were instituted beginning July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted, this mechanism ensures dollar for dollar recovery for prudently incurred fuel costs.

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

North Carolina Regulation

In 2004, the North Carolina Utilities Commission (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 annual reduction in current base rates and a five-year base rate moratorium, effective as of April 2005. Fuel rates are still subject to change under annual fuel cost adjustment proceedings.

Regional Transmission Expansion Plan

Each year, as part of PJM s RTEP process, reliability projects are authorized. In June 2006, PJM, through the RTEP process, authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects. The first project is an approximately 270-mile 500-kilovolt (kV) transmission line from southwestern Pennsylvania to northern Virginia, of which we will construct approximately 65 miles in Virginia and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. This project is estimated to cost approximately $243 million and is expected to be completed by June 2011. The second project is an approximately 60-mile 500 kV transmission line that we will construct in southeastern Virginia. This project is estimated to cost approximately $180 million and is expected to be completed in June 2011. These transmission upgrades are designed to improve the reliability of service to our customers and the region. The siting and construction of these transmission lines will be subject to applicable state and federal permits and approvals. In April 2007, we, along with Trans-Allegheny Interstate Line Company, filed an application with the Virginia Commission requesting approval of the proposed construction of the 65-mile transmission line in northern Virginia. In May 2007, we filed an application with the Virginia Commission requesting approval of the proposed construction of the 60-mile transmission line in southeastern Virginia. Evidentiary hearings on these applications commenced in February 2008.

Generation Expansion

Based on available generation capacity and current estimates of growth in customer demand in our utility service area, we will need additional generation capacity over the next ten years. We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market in Virginia. As part of this program, the following projects are in various stages of development:

In April 2007, we filed an application with the Virginia Commission requesting approval to add two 150 Mw natural gas-fired electric generating units (Units 3 and 4) to our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. The facility is expected to be in operation by August 2008, at an estimated cost of $135 million. The Virginia Commission approved the application in August 2007, and construction has commenced. In December 2007, we received approval from the North Carolina Commission for a related affiliate transaction.

In November 2007, we filed an application with the Virginia Commission for approval of a fifth combustion turbine (Unit 5) at Ladysmith, at an estimated cost of $79 million.

In July 2007, we filed an application with the Virginia Commission requesting approval to construct and operate a 585 Mw (nominal) carbon-capture compatible, clean-coal powered electric generation facility (Virginia City Hybrid Energy Center) to be located in Wise County, Virginia. We also requested approval to continue to accrue an allowance for funds used during construction until capped rates end and, beginning January 1, 2009, receive current recovery of financing costs, including a return on common equity of 11.75% together with a 200-basis point enhancement, through a rate adjustment clause. An evidentiary hearing was held in February 2008. An application for a permit to construct and operate the Virginia City Hybrid Energy Center, in compliance with federal and state air pollution laws, was filed in July 2006 with the Virginia Department of Environmental Quality. Pending regulatory approval and necessary permits, the facility is expected to be in operation by 2012 at an estimated capital cost of approximately $1.8 billion.

Also in February 2008, we announced the proposed conversion of our Bremo power station (Bremo) from coal to natural gas as part of our plan to build the Virginia City Hybrid Energy Center. The proposal is contingent upon the Virginia Hybrid Energy Center entering service and receiving approvals from the Virginia Commission and Virginia Department of Environmental Quality. This proposed conversion project is part of our overall effort to reduce air emissions. Subject to applicable regulatory approvals, the conversion would occur within two years of the Virginia City Hybrid Energy Center entering service.

We are considering the construction of a third nuclear unit within the next 20 years at a site located at the North Anna power station (North Anna), which we own along with Old Dominion Electric Cooperative (ODEC). In November 2007, the NRC issued an Early Site Permit (ESP) for the North Anna site. Also in November 2007, we along with ODEC, filed an application with the NRC for a Combined Construction Permit and Operating License (COL), which would allow us to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted our application for the COL and deemed it complete. Dominion has a cooperative agreement with the Department of Energy to share equally the cost of the COL. We have not yet committed to building a new unit.

In December 2007, we announced an agreement to purchase a power station development project in Buckingham County, Virginia that will generate about 600 Mw. The project already has air and water permits for a combined-cycle, natural gas-fired power station; however, such permits may need to be modified. In addition, construction of the project is subject to approval by the Virginia Commission, including approval under state regulations relating to bidding for the purchase of electric capacity and energy from other power suppliers, and the receipt of other environmental permits. A gas pipeline will also be required to be constructed to provide gas supply to the power station. Pending a closing under the purchase agreement and the receipt of regulatory approvals, we plan to build a combined cycle unit with operations expected to begin in summer 2011.

PJM Rate Design

In May 2005, FERC issued an order finding that PJM s existing transmission service rate design may not be just and reasonable, and ordered an investigation and hearings into the matter. In January 2008, FERC affirmed its earlier decision that the PJM transmission rate design for existing facilities had not become unjust and unreasonable. For recovery of costs of investments of new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a regional rate design where all customers pay a uniform rate based on the costs of such investment. For recovery of costs of investment in new PJM-planned transmission facilities that operate below 500kV, FERC affirmed its earlier decision to allocate costs on a beneficiary pays approach. A notice of appeal of this decision was filed in February 2008 at the United States Court of Appeals for the Seventh Circuit. We cannot predict the outcome of the appeal.

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, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we are allowed to seek recovery through rates.

Environmental Protection and Monitoring Expenditures

We incurred approximately $121 million, $102 million and $134 million of expenses (including depreciation) during 2007, 2006 and 2005, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately $139 million and $143 million in 2008 and 2009, respectively. In addition, capital expenditures related to environmental controls were $189 million, $170 million and $42 million for 2007, 2006 and 2005, respectively. These expenditures are expected to be approximately $129 million and $89 million for 2008 and 2009, respectively.

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 federal rules allow for the use of cap-and-trade programs. West Virginia has adopted final regulations for CAIR and CAMR. Virginia has adopted final regu-

lations for CAIR with requirements more strict than the federal rule and will adopt final regulations for CAMR with requirements more strict than the federal rule. These regulatory 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). 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 $350 million during the period 2008 through 2012. In February 2008, the U.S. Court of Appeals for the District of Columbia issued a ruling that vacates CAMR as promulgated by the EPA. At this time we cannot determine if this ruling will be subject to further appeals and how the EPA, and subsequently the states, may alter their approach to reducing mercury emissions. We also cannot estimate at this time the impact on our future capital expenditures.

Clean Water Act Compliance

In July 2004, the EPA published regulations under the Clean Water Act Section 316b 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. 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. In July 2007, the EPA suspended the regulations pending further rulemaking, consistent with the decision issued by the U. S. Court of Appeals for the Second Circuit. In November 2007, a number of industries appealed the lower court decision to the U. S. Supreme Court. We have eight facilities that are likely to be subject to these regulations. We cannot predict the outcome of the judicial or EPA regulatory processes, nor can we determine with any certainty what specific controls may be required.

Regulation of Greenhouse Gas Emissions

In April 2007, the U. S. Supreme Court ruled that the EPA has the authority to regulate greenhouse gas emissions which could result in future EPA action. In June 2007, the President announced U.S. support for an effort to develop a new post-2012 framework on climate change involving the top ten to fifteen greenhouse gas emitting countries that would focus on establishing a long-term global goal to reduce greenhouse gas emissions with each country establishing its own mid-term targets and programs. At the state level, the Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing greenhouse gas emissions statewide back to 2000 levels by 2025. The Governor has formed a Commission on Climate Change to develop a plan to achieve this goal. Until this goal results in legislative or regulatory action, the outcome in terms of

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specific requirements and timing is uncertain. The cost of compliance with future greenhouse gas reduction programs could be significant. Given the highly uncertain outcome and timing of future action by the U.S. federal government and states on this issue, we cannot predict the financial impact of future greenhouse gas reduction programs on our operations or our customers at this time.

Environmental Strategy

We are committed to being a good environmental steward. Our ongoing objective is to provide reliable, affordable energy for our customers while being environmentally responsible. Our integrated strategy to meet this objective consists of four major elements:

- Conservation and efficiency;
- Renewable generation development;
- Other generation development to maintain our fuel diversity, including clean coal, advanced nuclear energy, and natural gas; and
- Improvements in other energy infrastructure.

Conservation plays a critical role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides for incentives for energy conservation and sets a goal to reduce electricity consumption by retail customers in 2022 by ten percent of the amount consumed in 2006 through the implementation of conservation programs. We announced plans in September 2007 for a series of pilot programs focused on energy conservation and demand response.

The pilots will be offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results are representative, customers will not be able to volunteer for the pilots nor participate in more than one pilot. We will report results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness.

The pilots approved by the Virginia Commission include:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots are designed to cycle central heating and air conditioning units during peak-energy demand times, inform customers about their real-time energy consumption patterns, promote programmable thermostats that allow customers to control their use of electricity, and educate customers about the value of reducing energy use during peak-use times.
- Free energy audits and energy efficiency kits to 150 existing residential customers, 100 new homes meeting energy efficiency guidelines set by the EPA, and 50 small commercial customers. In addition, 250 new homes will receive energy efficiency welcome kits that include compact fluorescent light bulbs.
- Incentives for commercial customers to reduce load during periods of peak demand by running their generators to produce up to 100 Mw of electricity. This would be in addition to existing options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting goals for renewable power. We are committed to meeting Virginia s goal of 12% renewable power by 2022 and North Carolina s renewable portfolio standard of 12.5% by 2021.

We are actively assessing development opportunities in our service territories for renewable technologies. In November, 2007 we issued a request for proposals (RFP) for renewable energy projects in Virginia, North Carolina or elsewhere in the PJM Interconnect region. The RFP seeks the purchase of renewable energy generation projects, as well as renewable energy credits. Generation currently provides approximately two percent of its generation from renewable sources. We also anticipate using up to 20% biomass (woodwaste) at the proposed Virginia City Hybrid Energy Center.

We have announced a comprehensive generation growth program, referred to as *Powering Virginia*, which involves the development, financing, construction and operation of new multi-fuel, multi-technology generation capacity to meet the growing demand in our core market of Virginia. We expect that these investments collectively will provide the following benefits: expanded electricity production capability; increased technological and fuel diversity; and a reduction in the carbon dioxide (CO_2) emissions intensity of our generation fleet. A critical aspect of the

Powering Virginia program is the extent to which we seek to reduce the carbon intensity of our generation fleet by developing generation facilities with zero CO_2 and low CO_2 emissions, as well as economically viable facilities that can be equipped for CO_2 separation and sequestration. There is no current economically viable technological solution to retro-fit existing fossil-fueled technology to capture and sequester greenhouse gas emissions. Given that new generation units have useful lives of up to 50 years, we will give full consideration to CO_2 and other greenhouse gas emissions when making long-term investment decisions.

Finally, we plan to make a significant investment in improving the capabilities and reliability of our electric transmission and distribution system. These enhancements are primarily aimed at meeting our continued goal of providing reliable service. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed or to be developed in the future.

Future Environmental Regulations

We expect that there may be federal legislative or regulatory action regarding the regulation of greenhouse gas emissions and regarding compliance with more stringent air emission standards in the future. With respect to greenhouse gas emissions, the outcome in terms of specific requirements and timing is uncertain but may include a greenhouse gas emissions cap-and-trade program or a carbon tax for electric generators and natural gas businesses. With respect to emission reductions, specific requirements under consideration would be phased in under periods of up to ten to fifteen years. If any of these new proposals are adopted, additional significant expenditures may be required.

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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, 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 electricity, natural gas, and other commodities. 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 and interest rates.

Commodity Price Risk

To manage price risk, we primarily hold commodity-based financial derivative instruments for non-trading purposes associated with the purchase of electricity, natural gas and other energy- related products. The derivatives used to manage our commodity price risk are executed within established policies and procedures and may include instruments such as futures, swaps, forwards, options and FTRs 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 $27 million and $3 million in the fair value of our non-trading commodity-based financial derivatives as of December 31, 2007 and 2006, respectively. The increase is primarily due to an increase in electricity-related derivatives executed during 2007.

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.

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, 2007 and 2006, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $3 million and $6 million, respectively. The decrease is primarily due to a decrease in variable rate debt.

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.

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

We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $28 million and $36 million in 2007 and 2006, respectively. In 2007, we recorded unrealized gains on these investments of $13 million to regulatory liabilities and AOCI. We recorded, in AOCI, unrealized gains on these investments of $86 million in 2006.

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, 2007 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 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, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for uncertain tax positions in 2007 and conditional asset retirement obligations in 2005.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 26, 2008

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Consolidated Statements of Income

Year Ended December 31, (millions)	**2007**	2006	2005
Operating Revenue	**$ 6,181**	$ 5,603	$ 5,712
Operating Expenses			
Electric fuel and energy purchases	**2,478**	2,384	2,553
Purchased electric capacity	**429**	453	477
Other energy-related commodity purchases	**27**	56	34
Other operations and maintenance:			
Affiliated suppliers	**345**	311	292
Other	**935**	717	653
Depreciation and amortization	**568**	536	527
Other taxes	**173**	163	170
Total operating expenses	**4,955**	4,620	4,706
Income from operations	**1,226**	983	1,006
Other income	**55**	75	70
Interest and related charges:			
Interest expense	**274**	266	292
Interest expense junior subordinated notes payable to affiliated trust	**30**	30	30
Total interest and related charges	**304**	296	322
Income from continuing operations before income tax expense, extraordinary item and cumulative effect of change in accounting principle	**977**	762	754
Income tax expense	**371**	284	269
Income from continuing operations before extraordinary item and cumulative effect of change in accounting principle	**606**	478	485
Loss from discontinued operations[1]			(471)
Extraordinary item[2]	**(158)**		
Cumulative effect of change in accounting principle[3]			(4)
Net Income	**448**	478	10
Preferred dividends	**16**	16	16
Balance available for common stock	**$ 432**	$ 462	$ (6)

(1) Net of income tax benefit of $274 million in 2005.
(2) Net of income tax benefit of $101 million in 2007.
(3) Net of income tax benefit of $3 million in 2005.
The accompanying notes are an integral part of our Consolidated Financial Statements.

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Consolidated Balance Sheets

At December 31, (millions)	2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 49**	$ 18
Customer receivables (less allowance for doubtful accounts of $8 and $7)	**763**	650
Affiliated receivables	**53**	18
Other receivables (less allowance for doubtful accounts of $9 at both dates)	**58**	80
Inventories (average cost method):		
Materials and supplies	**248**	231
Fossil fuel	**272**	274
Prepayments	**165**	133
Other	**86**	51
Total current assets	**1,694**	1,455
Investments		
Nuclear decommissioning trust funds	**1,339**	1,293
Other	**16**	22
Total investments	**1,355**	1,315
Property, Plant and Equipment		
Property, plant and equipment	**21,838**	20,771
Accumulated depreciation and amortization	**(8,702)**	(8,353)
Total property, plant and equipment, net	**13,136**	12,418
Deferred Charges and Other Assets		
Intangible assets	**176**	195
Regulatory assets	**564**	241
Other	**132**	59
Total deferred charges and other assets	**872**	495
Total assets	**$ 17,057**	$ 15,683

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At December 31, (millions)	2007	2006
LIABILITIES AND SHAREHOLDER S EQUITY		
Current Liabilities		
Securities due within one year	**$ 286**	$ 1,267
Short-term debt	**257**	618
Accounts payable	**573**	418
Payables to affiliates	**80**	62
Affiliated current borrowings	**114**	140
Accrued interest, payroll and taxes	**234**	227
Customer deposits	**116**	109
Other	**117**	100
Total current liabilities	**1,777**	2,941
Long-Term Debt		
Long-term debt	**4,904**	2,987
Junior subordinated notes payable to affiliated trust	**412**	412
Notes payable other affiliates		220
Total long-term debt	**5,316**	3,619
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,237**	2,308
Asset retirement obligations	**678**	641
Regulatory liabilities	**1,009**	430
Other	**242**	95
Total deferred credits and other liabilities	**4,166**	3,474
Total liabilities	**11,259**	10,034
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	**1,109**	887
Retained earnings	**1,015**	955
Accumulated other comprehensive income	**29**	162
Total common shareholder s equity	**5,541**	5,392
Total liabilities and shareholder s equity	**$ 17,057**	$ 15,683

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

(millions, except for shares)	Common Stock Shares (thousands)	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 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					(8)	(8)
Net unrealized gains on nuclear decommissioning trust funds, net of $8 tax					13	13
Amounts reclassified to net income:						
Net realized gains on nuclear decommissioning trust funds, net of $4 tax					(7)	(7)
Net derivative gains hedging activities, net of $7 tax					(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					(10)	(10)
Changes in unrealized gains on nuclear decommissioning trust funds, net of $40 tax					62	62
Amounts reclassified to net income:						
Net realized gains on nuclear decommissioning trust funds, net of $7 tax					(9)	(9)
Net derivative losses hedging activities, net of $2 tax					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
Comprehensive income:						
Net income				**448**		**448**
Net deferred derivative losses hedging activities, net of $1 tax					**(1)**	**(1)**
Changes in unrealized gains on nuclear decommissioning trust funds, net of $80 tax					**(125)**	**(125)**
Amounts reclassified to net income:						
Net realized gains on nuclear decommissioning trust funds, net of $2 tax					**(3)**	**(3)**
Net derivative gains hedging activities, net of $2 tax					**(4)**	**(4)**
Total comprehensive income				**448**	**(133)**	**315**
Equity contribution by parent			**220**			**220**

Tax benefit from stock awards and stock options exercised			2			2
Adoption of FIN 48				5		5
Dividends				(393)		(393)
Balance at December 31, 2007	198	$ 3,388	$ 1,109	$ 1,015	$ 29	$ 5,541

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)	2007	2006	2005
Operating Activities			
Net income	**$ 448**	$ 478	$ 10
Adjustments to reconcile net income to net cash from operating activities:			
Net realized and unrealized derivative (gains)/losses	**(67)**	(2)	1,041
Depreciation and amortization	**654**	619	604
Deferred income taxes and investment tax credits, net	**256**	24	(267)
Deferred fuel expenses, net	**(315)**	99	76
Extraordinary item, net of income taxes	**158**		
Gain on sale of emissions allowances held for consumption	**(19)**	(74)	(54)
Other adjustments	**(39)**	(27)	9
Changes in:			
Accounts receivable	**(77)**	30	(149)
Affiliated accounts receivable and payable	**(17)**	6	(40)
Inventories	**(15)**	(62)	(18)
Pension assets		35	56
Accounts payable	**165**	1	253
Accrued interest, payroll and taxes	**7**	(61)	164
Margin deposit assets and liabilities		11	(69)
Other operating assets and liabilities	**77**	3	(120)
Net cash provided by operating activities	**1,216**	1,080	1,496
Investing Activities			
Plant construction and other property additions	**(1,184)**	(925)	(741)
Purchases of nuclear fuel	**(111)**	(122)	(111)
Purchases of securities	**(551)**	(550)	(311)
Proceeds from sales of securities	**520**	533	257
Proceeds from sale of emissions allowances held for consumption	**9**	75	56
Other	**11**	29	50
Net cash used in investing activities	**(1,306)**	(960)	(800)
Financing Activities			
Issuance (repayment) of short-term debt, net	**(361)**	(287)	638
Issuance (repayment) of affiliated current borrowings, net	**(26)**	129	(256)
Issuance of long-term debt	**2,250**	1,000	
Repayment of long-term debt	**(1,335)**	(624)	(532)
Common dividend payments	**(377)**	(349)	(454)
Preferred dividend payments	**(16)**	(16)	(16)
Other	**(14)**	(9)	(24)
Net cash provided by (used in) financing activities	**121**	(156)	(644)
Increase (decrease) in cash and cash equivalents	**31**	(36)	52
Cash and cash equivalents at beginning of year	**18**	54	2
Cash and cash equivalents at end of year	**$ 49**	$ 18	$ 54
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 305**	$ 254	$ 307
Income taxes	**211**	419	156
Significant noncash investing and financing activities:			
Assumption of debt related to acquisitions of nonutility generating facilities			62
Issuance of debt in exchange for electric distribution assets			8
Issuance of long-term debt and establishment of trust	**14**		

Conversion of short-term and long-term borrowings payable to parent to other paid-in capital	**220**	200
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 regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2007, we served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. We are a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), and our electric transmission facilities are integrated into the PJM wholesale electricity markets. All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion).

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 2005 were adjusted to reflect VPEM as a discontinued operation. In addition, the discontinued operations of VPEM are included in our Corporate and Other segment results.

Prior to a fourth quarter 2007 segment realignment, we managed our daily operations through three primary operating segments: Delivery, Energy and Generation. During the fourth quarter of 2007, we realigned our business units and began managing our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. In addition, we also report a Corporate and Other segment that includes our corporate and other functions. Corporate and Other also includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management, in assessing the segments performance or allocating resources among the segments. Our assets remain wholly owned by us and our legal subsidiaries.

The terms Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Electric and Power Company, one or more 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 2006 and 2005 Consolidated Financial Statements and footnotes have been recast to conform to the 2007 presentation.

Reapplication of SFAS No. 71

In March 1999, we discontinued the application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), to the majority of our generation operations upon the enactment of deregulation legislation in Virginia. Our transmission and distribution operations continued to apply the provisions of SFAS No. 71 since they remained subject to cost-of-service rate regulation.

In April 2007, the Virginia General Assembly passed legislation that returns the Virginia jurisdiction of our generation operations to cost-of-service rate regulation. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. In connection with the reapplication of SFAS No. 71 to those operations, we prospectively changed certain of our accounting policies to those used by cost-of-service rate-regulated entities. Other than the extraordinary item discussed here, the overall impact of these changes was not material to our results of operations or financial condition in 2007. These policy changes are discussed further in *Derivative Instruments, Nuclear Decommissioning Trust Funds, Property, Plant and Equipment* and *Asset Retirement Obligations.*

The reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations resulted in a $259 million ($158 million after tax) extraordinary charge and the reclassification of $195 million ($119 million after tax) of unrealized gains from accumulated other comprehensive income (AOCI), related to nuclear decommissioning trust funds. This established a $454 million long-term regulatory liability for amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143).

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer receivables at December 31, 2007 and 2006 included $270 million and $233 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to our customers. We estimate unbilled revenue based on historical usage, applicable customer rates, weather factors and total daily electric generation supplied after adjusting for estimated losses of energy during transmission.

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Notes to Consolidated Financial Statements, Continued

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

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of excess generation sold at market-based rates, miscellaneous service revenue from electric distribution operations and other miscellaneous revenue.

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.

For electric fuel and purchased energy expenses, 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 was adjusted as discussed under *Virginia Fuel Expenses* in Note 21. Approximately 83% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is currently subject to deferral accounting.

Income Taxes

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

SFAS No. 109, *Accounting for Income Taxes* (SFAS No. 109), 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.

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). In our financial statements, we recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If we conclude that it is more-likely-than-not that a tax position, or some portion thereof, will not be sustained, the related tax benefits are not recognized in the financial statements. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of an income tax refund receivable, an increase in deferred tax liabilities, or a

decrease in deferred tax assets. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refund receivable) is accompanied by a decrease in deferred tax liabilities. Noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities; current payables are included in accrued interest, payroll and taxes, except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities in prepayments.

Prior to the adoption of FIN 48, we established liabilities for tax-related contingencies when the incurrence of the liability was determined to be probable and the amount could be reasonably estimated in accordance with SFAS No. 5, *Accounting for Contingencies,* and reviewed them in light of changing facts and circumstances.

We recognize changes in estimated interest payable on net underpayments and overpayments of income taxes in interest expense and estimated penalties that may result from the settlement of some uncertain tax positions in other income. In our Consolidated Statements of Income for 2007, 2006 and 2005, we recognized reductions of interest expense of $6 million, $1 million and $2 million, respectively, and no penalties. At December 31, 2007, we had accrued $5 million for interest receivable and $2 million for interest payable and penalties. At December 31, 2006, we had accrued $3 million for interest receivable and no penalties.

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

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

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2007 and 2006, accounts payable included $31 million and $33 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 to manage the commodity and financial market risks of our business operations.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), 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.

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

Derivative Instruments Designated as Hedging Instruments

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

Cash Flow Hedges A portion of our hedge strategies represents cash flow hedges of the variable price risk associated with the purchase of natural gas, electricity and other energy-related products. We also use foreign currency forward contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of these derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings. 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 on certain fixed-rate long-term debt to manage our interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value. Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of these derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments subject to regulatory accounting are generally recognized when the related transactions impact earnings. For fair value hedge transactions, we discontinue hedge accounting if the hedged item no longer qualifies for hedge accounting. We reclassify derivative gains and losses from the hedged item to earnings when the hedged item is included in earnings, or earlier, if the hedged item no longer qualifies for hedge accounting.

Statement of Income Presentation Gains and losses on derivatives designated as hedges, when recognized, are included in operating revenue, operating expenses or interest and related charges in our Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. The portion of gains or losses on hedging instruments determined to be ineffective and the portion of gains or losses on hedging instruments excluded from the measurement of the hedging relationship s effectiveness, such as gains or losses attributable to changes in the time value of options, 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, our Consolidated Statement of Income for 2005 reflects VPEM as a discontinued operation.

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Notes to Consolidated Financial Statements, Continued

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 net realized and unrealized gains and losses and other-than-temporary impairments recorded to the regulatory liability for certain jurisdictions subject to cost-of-service rate regulation as established upon the reapplication of SFAS No. 71. We continue to report realized gains and losses and any other-than-temporary declines in fair value for jurisdictions that are not subject to cost-based regulation in other income and unrealized gains as a component of AOCI, net of tax.

We analyze all securities classified as available for sale to determine whether a decline in fair value should be considered other than temporary. We use several criteria to evaluate other-than-temporary declines, including 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 is determined to be other than temporary, the security is written down to its fair value at the end of the reporting period.

Our method of assessing other-than-temporary declines requires demonstrating the intent and ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since 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, consisting of labor, materials and other direct and indirect costs such as asset retirement costs, capitalized interest and for certain operations subject to cost of service rate regulation, an allowance for funds used during construction (AFUDC). The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred. In 2007, 2006 and 2005, we capitalized interest costs and AFUDC of $28 million, $21 million and $8 million, respectively. Upon reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations in April 2007, we discontinued capitalizing interest on generation-related construction projects since the Virginia State Corporation Commission (Virginia Commission) previously allowed for current recovery of construction financing costs.

For property subject to cost-of-service rate regulation, which includes distribution, transmission and generation property effective April 2007, the undepreciated 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.

Prior to the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations, cost of removal not associated with AROs was charged to expense as incurred. We also recorded gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property s net book value at the retirement date.

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

Year Ended December 31,	**2007**	2006	2005
(percent)			
Generation[1]	**2.24**	2.07	2.04
Transmission	**1.98**	1.97	1.97
Distribution	**3.38**	3.45	3.46
General and other	**4.57**	4.93	5.43

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

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

Emissions Allowances

Emissions allowances are issued by the Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide and nitrogen oxide. Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation operations

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are held primarily for consumption and are classified as intangible assets in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances. Allowances issued directly to us by the EPA are carried at zero cost.

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

Impairment of Long-Lived and Intangible Assets

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

Regulatory Assets and Liabilities

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

Asset Retirement Obligations

We recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed. These amounts are capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, we estimate fair value using discounted cash flow analyses. With the reapplication of SFAS No. 71 for the Virginia jurisdiction of our generation operations on April 4, 2007, we now report accretion of the AROs associated with nuclear decommissioning due to the passage of time as an adjustment to the related regulatory liability. Previously, we reported such expense in other operations and maintenance expense in our Consolidated Statements of Income. We report accretion of all other AROs in other operations and maintenance expense in our Consolidated Statements of Income.

Amortization of Debt Issuance Costs

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

Note 3. Newly Adopted Accounting Standards

2007

FIN 48

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

In May 2007, the FASB issued FASB Staff Position (FSP) No. FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48* (FSP FIN 48-1), to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. In light of its delayed issuance, if an enterprise did not implement FIN 48 in a manner consistent with the provisions of FSP FIN 48-1, it was required to retrospectively apply its provisions to the date of its initial adoption of FIN 48. The adoption of FSP FIN 48-1 had no impact on the amounts recorded in connection with the adoption of FIN 48.

As of January 1, 2007, our unrecognized tax benefits totaled $225 million. For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

EITF 06-3

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

2005

FIN 47

We adopted 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 ARO 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 ARO 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.

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Notes to Consolidated Financial Statements, Continued

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

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

If we had applied the provisions of FIN 47 as of January 1, 2005, our AROs would have increased by $8 million.

NOTE 4. RECENTLY ISSUED ACCOUNTING STANDARDS

SFAS NO. 157

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

In February 2008, the FASB issued FSP FAS No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Its Related Interpretive Accounting Pronouncements That Address Leasing Transactions*, which excludes leasing transactions from the scope of SFAS No. 157. However, the exclusion does not apply to fair value measurements of assets and liabilities recorded as a result of a lease transaction but measured pursuant to other pronouncements within the scope of SFAS No. 157.

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

In January 2008, the FASB proposed FSP FAS No. 157-c, *Measuring Liabilities Under FASB Statement No. 157*, which if issued, would clarify the principles in SFAS No. 157 for the fair

value measurements of liabilities. Specifically, this FSP would require an entity to measure liabilities first based on a quoted price in an active market for an identical liability, however in the absence of such information, an entity would be allowed to measure the fair value of the liability at the amount it would receive as proceeds if it were to issue that liability at the measurement date.

SFAS NO. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 provides an entity with the option, at specified election dates, to measure certain financial assets and liabilities and other items at fair value, with changes in fair value recognized in earnings as those changes occur. SFAS No. 159 also establishes presentation and disclosure requirements that include displaying the fair value of those assets and liabilities for which the entity elected the fair value option on the face of the balance sheet and providing management s reasons for electing the fair value option for each eligible item. The provisions of SFAS No. 159 became effective for us beginning January 1, 2008. We are currently evaluating whether fair value accounting is appropriate for any of our eligible items and cannot estimate the impact that SFAS No. 159 may have on our results of operations and financial condition.

SFAS NO. 141R

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R). SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. SFAS No. 141R amends SFAS No. 109, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. The provisions of SFAS No. 141R will become effective for acquisitions on or after January 1, 2009, except for the tax provisions which apply to business combinations regardless of the acquisition date.

FSP FIN 39-1

In April 2007, the FASB issued FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts* (FSP FIN 39-1). FSP FIN 39-1 amends FIN 39 to permit the offsetting of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement that have been offset. FSP FIN 39-1 became effective for us beginning January 1, 2008 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. We are currently evaluating the impact that FSP FIN 39-1 may have on our financial condition. We do not expect FSP FIN 39-1 to have an impact on our results of operations or cash flows.

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Note 5. Operating Revenue

Our operating revenue consists of the following:

Year Ended December 31, (millions)	**2007**	2006	2005
Regulated electric sales	**$ 6,044**	$ 5,451	$ 5,543
Other	**137**	152	169
Total operating revenue	**$ 6,181**	$ 5,603	$ 5,712

Note 6. Income Taxes

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

Year Ended December 31, (millions)	**2007**	2006	2005
Current expense:			
Federal	**$ 152**	$ 213	$ 157
State	**(37)**	47	40
Total current	**115**	260	197
Deferred expense:			
Federal	**163**	29	88
State	**103**	10	(1)
Total deferred	**266**	39	87
Amortization of deferred investment tax credits	**(10)**	(15)	(15)
Total income tax expense	**$ 371**	$ 284	$ 269

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

Year Ended December 31,	**2007**	2006	2005
U.S statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
State income tax, net of federal tax benefit	**4.4**	4.8	3.4
Amortization of investment tax credits	**(0.8)**	(1.5)	(1.6)
Domestic production activities deduction	**(0.2)**		
Employee benefits	**(0.3)**	(0.2)	(0.6)
Other, net	**(0.1)**	(0.8)	(0.5)
Effective tax rate	**38.0%**	37.3%	35.7%

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

As of December 31,	**2007**	2006
(millions)		
Deferred income taxes:		
Total deferred income tax assets	**$ 643**	$ 161
Total deferred income tax liabilities	**2,824**	2,398
Total net deferred income tax liabilities	**$ 2,181**	$ 2,237
Total deferred income taxes:		
Depreciation method and plant basis differences	**$ 1,980**	$ 2,072
Deferred state income taxes	**185**	187
Unrealized gains on available-for-sale securities	**11**	81
Loss and credit carryforwards		(63)
Other	**5**	(40)
Total net deferred income tax liabilities	**$ 2,181**	$ 2,237

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

Prior to 2007, we established liabilities for income tax-related contingencies when we believed that it was probable that a liability had been incurred and the amount could be reasonably estimated and subsequently reviewed them in light of changing facts and circumstances. At December 31, 2006, our Consolidated Balance Sheet included no material income tax-related contingent liabilities.

With the adoption of FIN 48, effective January 1, 2007, we recognize in the financial statements only those positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. If we take or expect to take a tax return position and any portion of the related tax benefit is not recognized in the financial statements, we disclose such amount as an unrecognized tax benefit. These unrecognized tax benefits impact the financial statements by increasing taxes payable, reducing tax refund receivables, increasing deferred tax liabilities or decreasing deferred tax assets. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in taxes payable (or reduction in tax refund receivable) is accompanied by a decrease in deferred tax liabilities.

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Notes to Consolidated Financial Statements, Continued

A reconciliation of changes in our unrecognized tax benefits during 2007 follows:

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

Unrecognized tax benefits that, if recognized, would affect the effective tax rate, increased from $5 million at January 1, 2007 to $8 million at December 31, 2007, resulting in a $3 million increase in total income tax expense for 2007.

For the majority of our unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility. When uncertainty about the deductibility of amounts is limited to the timing of such deductibility, any tax liabilities recognized for prior periods would be subject to offset with the availability of refundable amounts from later periods when such deductions could otherwise be taken. Pending resolution of these timing uncertainties, interest is being accrued until the period in which the amounts would become deductible.

For Dominion and its subsidiaries, the U.S. federal statute of limitations has expired for tax years prior to 1999, except that we have reserved the right to pursue refunds related to certain deductions for the years 1995 through 1998.

In 2007, the U.S. Congressional Joint Committee on Taxation completed its review of our settlement with the Appellate Division of the Internal Revenue Service (IRS Appeals) for tax years 1993 through 1997. In October of 2007, we received a tax refund of approximately $33 million for those years. Due to carryback adjustments, we will not receive the refund for 1998 until issues for later tax years, pending at IRS Appeals, are settled.

We are currently engaged in settlement negotiations with IRS Appeals regarding certain adjustments proposed during the examination of tax years 1999 through 2001. We have reached tentative settlement on substantially all of the issues, except we are reserving the right to pursue refunds related to certain deductions. Negotiations are expected to conclude in 2008, without any impact on our results of operations. In 2007, the IRS completed its examination of Dominion s 2002 and 2003 consolidated returns. We filed protests for certain proposed adjustments with IRS Appeals in July 2007. In addition, the IRS began its audit of tax years 2004 and 2005 in November 2007.

With our appeals of assessments received from tax authorities including amounts related to our settlement negotiations with IRS Appeals for 1999 - 2001, we believe that it is reasonably possible that, based on settlement negotiations and risk of litigation, unrecognized tax benefits could decrease by up to $18 million over the next twelve months. In addition, unrecognized tax benefits could be reduced by $13 million to recognize prior period amounts becoming otherwise deductible in the current period. With regard to tax years 2002 2005, we cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur during the next twelve months.

Dominion s combined income tax returns filed with Virginia for 2004 and subsequent years remain subject to examination. We are also obligated to report adjustments resulting from IRS settlements of earlier years to state tax authorities. In addition, if state net operating losses or tax credits, generated by Dominion and its subsidiaries in years for which the statute of limitations has expired, are utilized, such amounts are subject to examination by state tax authorities.

In February 2008, the President of the U.S. signed into law the Economic Stimulus Act of 2008 (the Act). The Act includes provisions to stimulate economic growth, including incentives for increased capital investment by businesses. We are currently evaluating the Act but have not yet determined its impact on our 2008 and future results of operations, cash flows or financial condition.

NOTE 7. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products, as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate derivative instruments as cash flow or fair value hedges for accounting purposes as allowed by SFAS No. 133. As discussed in Note 2, for jurisdictions subject to cost-based regulation, changes in the fair value of derivatives designated as hedges are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings.

For the years ended December 31, 2007 and 2006, gains or losses on hedging instruments determined to be ineffective and excluded from the measurement of effectiveness were not material. 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, for jurisdictions that are not subject to cost-based regulation, related to cash flow hedges included in AOCI in our Consolidated Balance Sheet at December 31, 2007:

(millions)	AOCI After Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After Tax	Maximum Term
Foreign currency	**$ 2**		**39 months**
Other	**5**	**3**	**117 months**
Total	**$ 7**	**$ 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 Statement of Income for 2005 reflects VPEM as a discontinued operation, on a net basis. For 2005, our discontinued operations included operating revenue of $807 million and a loss before income taxes of $746 million. VPEM s 2005 results included the following affiliated transactions:

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

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, 2007 and 2006, are summarized below. There were no unrealized losses included in AOCI as of December 31, 2007 or 2006.

(millions)	Fair Value	Total Unrealized Gains
2007		
Equity securities	**$ 844**	**$ 245**
Debt securities	**468**	**13**
Cash and other	**27**	
Total	**$ 1,339**	**$ 258**(1)
2006		
Equity securities	$ 833	$ 239
Debt securities	425	7
Cash and other	35	

Total	$ 1,293	$ 246(2)

(1) Included in AOCI and regulatory liabilities as discussed in Note 2.
(2) Included in AOCI in our Consolidated Balance Sheet.

The fair values of debt securities within the nuclear decommissioning trust funds at December 31, 2007 by contractual maturity are as follows:

(millions)	Amount
Due in one year or less	**$ 14**
Due after one year through five years	**153**
Due after five years through ten years	**119**
Due after ten years	**182**
Total	**$ 468**

Gross realized gains on our available-for-sale securities totaled $52 million, $49 million and $19 million in 2007, 2006 and 2005, respectively, and gross realized losses totaled $52 million, $33 million and $8 million in 2007, 2006 and 2005, respectively. Gross realized gains and losses for 2007 include amounts recorded to a regulatory liability as discussed in Note 2. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

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

At December 31, (millions)	**2007**	2006
Utility:		
Generation	**$ 10,237**	$ 10,088
Transmission	**1,942**	1,777
Distribution	**6,931**	6,613
Nuclear fuel	**930**	907
General and other	**591**	592
Other including plant under construction	**1,200**	787
Total utility	**21,831**	20,764
Nonutility other	**7**	7
Total property, plant and equipment	**$ 21,838**	$ 20,771

Jointly-Owned Plants

Our proportionate share of jointly-owned plants at December 31, 2007 is as follows:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station

(millions, except percentages)			
Ownership interest	60.0%	88.4%	50.0%
Plant in service	$ 1,013	$ 2,053	$ 557
Accumulated depreciation	(415)	(998)	(141)
Nuclear fuel		457	
Accumulated amortization of nuclear fuel		(356)	
Other-including plant under construction	10	110	1

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

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Notes to Consolidated Financial Statements, Continued

NOTE 11. INTANGIBLE ASSETS

All of our intangible assets are subject to amortization over their estimated useful lives. Amortization expense for intangible assets was $46 million, $37 million and $38 million for 2007, 2006 and 2005, respectively. In 2007, we acquired $22 million of intangible assets, primarily representing software and emissions allowances, with an estimated weighted-average amortization period of 5.4 years. The components of our intangible assets are as follows:

At December 31,	2007		2006	
	Gross Carrying Amount	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	**$ 240**	**$ 165**	$ 259	$ 165
Emissions allowances	**75**	**15**	63	4
Other	**53**	**12**	52	10
Total	**$ 368**	**$ 192**	$ 374	$ 179

Annual amortization expense for these intangible assets is estimated to be $26 million for 2008, $27 million for 2009, $28 million for 2010, $14 million for 2011 and $10 million for 2012.

NOTE 12. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	2007	2006
(millions)		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	**$ 386**	$ 72
RTO start-up costs and administration fees (2)	**95**	66
Income taxes recoverable through future rates(3)	**30**	46
Termination of certain power purchase agreements(4)	**20**	22
Other	**33**	35
Total regulatory assets	**$ 564**	$ 241
Regulatory liabilities:		
Provision for future cost of removal(5)	**$ 453**	$ 409
Decommissioning trust(6)	**487**	13
Other	**69**	8
Total regulatory liabilities	**$ 1,009**	$ 430

(1)

As discussed under Virginia Fuel Expenses in Note 21, in June 2007, the Virginia Commission approved a fuel factor increase of approximately $219 million, effective July 1, 2007, with the balance of approximately $443 million to be deferred and subsequently recovered, without interest, during the period commencing July 1, 2008, and ending June 30, 2011.

(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 $81 million in start-up costs and administration fees and $14 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) 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.

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

At December 31, 2007, approximately $532 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs, RTO start-up costs and administration fees, and the cost of terminating certain power purchase agreements.

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 2007 were as follows:

(millions)	Amount
AROs at December 31, 2006	$ 641
Obligations incurred during the period	**4**
Obligations settled during the period	**(1)**
Accretion	**38**
Other	**(3)**
AROs at December 31, 2007(1)	**$ 679**

(1) Includes $1 million reported in other current liabilities.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2007 and 2006, the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $1.3 billion.

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

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investors lack any of the following characteristics of a controlling financial interest:

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

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

We have long-term power and capacity contracts with 4 potential VIEs, which contain certain variable pricing mechanisms to the counterparty in the form of partial fuel reimbursement. We have concluded that we are not the primary beneficiary of any of these potential VIEs. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $2.1 billion as of December 31, 2007. We paid $211 million, $214 million and $222 million for electric capacity and $160 million, $130 million and $159 million for electric energy to these entities for the years ended December 31, 2007, 2006 and 2005, respectively.

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

In 2007, we purchased approximately $344 million of shared services from Dominion Resources Services, Inc. (DRS), a VIE of which we are not the primary beneficiary.

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 levels 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 with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and 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, 2007, total outstanding commercial paper supported by the joint credit facility was $757 million, of which our borrowings were $257 million, with a weighted-average interest rate of 5.68%. At December 31, 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, 2007, total outstanding letters of credit supported by the joint credit facility were $229 million, of which less than $8 million were issued on our behalf. At December 31, 2006, total outstanding letters of credit supported by the joint credit facility were $236 million, of which less than $1 million were issued on our behalf.

At December 31, 2007, capacity available under the joint credit facility was $2.0 billion.

NOTE 16. LONG-TERM DEBT

At December 31, (millions, except percentages)	2007 Weighted-Average Coupon(1)	2007	2006
Secured First and Refunding Mortgage Bonds, 7.625%, due 2007(2):		$	$ 215
Secured Bank Debt, Variable rate, due 2007(3)			370
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.73%, due 2007 to 2012	**5.03%**	**950**	1,000
4.75% to 8.625%, due 2013 to 2037	**5.83%**	**3,385**	1,748
Unsecured Callable and Puttable Enhanced Securities^SM, 4.10% due 2038(4)		**225**	225
Tax-Exempt Financings(5):			
Variable rate, due 2008	**3.86%**	**60**	60
Variable rates, due 2015 to 2027	**3.80%**	**137**	137
4.95% to 7.65%, due 2007 to 2010:	**5.42%**	**205**	232
4.25% to 7.55%, due 2014 to 2031:	**5.26%**	**223**	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(6)			220
		5,597	4,882
Fair value hedge valuation(7)			(8)
Amount due within one year	**5.28%**	**(286)**	(1,267)
Unamortized discount and premium, net		**5**	12
Total long-term debt		**$ 5,316**	$ 3,619

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2007.

(2) Substantially all of our property is subject to the lien of the mortgage securing our First and Refunding Mortgage Bonds. Although there are no publicly issued bonds outstanding as of December 31, 2007, we may issue additional bonds in the future.

(3) Represented debt associated with a special purpose lessor entity consolidated in accordance with FIN 46R. The debt was nonrecourse to us and was secured by the entity s property, plant and equipment, which totaled $337 million at December 31, 2006. This debt was repaid in August 2007, when the lease terminated.

(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 $200 million 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) In December 2007, we recorded contributed capital of $220 million reflecting the conversion of this note payable to equity.

(7) Represents the valuation of certain fair value hedges associated with our fixed rate debt. Following the reapplication of SFAS No. 71, for jurisdictions subject to cost-based regulation, changes in the fair value of these derivative instruments are classified as regulatory assets or liabilities.

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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, 2007 were as follows:

(millions)	2008	2009	2010	2011	2012	Thereafter	Total
	$ 286	**$ 124**	**$ 246**	**$ 15**	**$ 616**	**$ 4,310**	**$ 5,597**

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2007, 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. We may defer interest payments on the junior subordinated notes on one or more occasions for up to five consecutive years and the related trust must also defer distributions. 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, 2007 and 2006. Upon involuntary liquidation, dissolution or winding-up of the Company, each share would be entitled to receive $100 plus accrued dividends. Dividends are cumulative.

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

Presented below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2007:

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**	**102.12**(1)
6.98	**600**	**102.10**(2)
Flex MMP 12/02, Series A	**1,250**	**100.00**(3)
Total	**2,590**	

(1) Through 7/31/2008; $101.77 commencing 8/1/2008; amounts decline in steps thereafter to $100.00 by 8/1/2013.
(2) Through 8/31/2008; $101.75 commencing 9/1/2008; amounts decline in steps thereafter to $100.00 by 9/1/2013.
(3) Dividend rate was 5.50% through 12/20/2007. Dividend rate is now 6.25% through 3/20/2011; after which, the rate will be determined according to periodic auctions for periods established by us at the time of the auction process.

NOTE 18. SHAREHOLDER S EQUITY

Other Paid-In Capital

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

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.

Accumulated Other Comprehensive Income

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

At December 31,	**2007**	2006
(millions)		
Net unrealized gains on derivatives hedging activities, net of $5 and $8 tax, respectively	**$ 7**	$ 12
Net unrealized gains on nuclear decommissioning trust funds, net of $14 and $96 tax, respectively	**22**	150
Total AOCI	**$ 29**	$ 162

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, 2007, the Virginia Commission had not restricted our payment of dividends.

Certain agreements associated with our joint credit facility with Dominion contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends to Dominion at December 31, 2007.

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 $37 million, $63 million and $56 million in 2007, 2006 and 2005, respectively. We did not contribute to the pension plan in 2007, 2006 or 2005.

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 $24 million, $37 million and $42 million in 2007, 2006 and 2005, 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 $7 million, $24 million and $32 million in 2007, 2006 and 2005, respectively. We expect to contribute $16 million to retiree health care and life insurance plans in 2008.

We also participate in Dominion-sponsored employee savings plans that cover substantially all employees. Employer matching contributions of $12 million were incurred in 2007 and $11 million each were incurred in 2006 and 2005.

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. The ultimate outcome of such proceedings cannot be predicted at this time, however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2007, 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)	2008	2009	2010	2011	2012	Thereafter	Total
Purchased electric capacity(1)	**$ 383**	**$ 364**	**$ 349**	**$ 348**	**$ 352**	**$ 1,857**	**$ 3,653**

(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, 2007, the present value of our total commitment for capacity payments is $2.4 billion. Capacity payments totaled $410 million, $437 million and $472 million, and energy payments totaled $360 million, $291 million and $378 million for 2007, 2006, and 2005, respectively.

Lease Commitments

We lease various facilities, vehicles and equipment primarily under operating leases. The lease agreements expire on various dates and certain of the leases are renewable and contain options to purchase the leased property. Payments under certain leases are escalated based on an index such as the Consumer Price Index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2007 are as follows:

(millions)	2008	2009	2010	2011	2012	Thereafter	Total
	$ 29	**$ 26**	**$ 21**	**$ 17**	**$ 12**	**$ 23**	**$ 128**

Rental expense totaled $37 million, $34 million and $32 million for 2007, 2006 and 2005, respectively, the majority of which is reflected in other operations and maintenance expense.

Environmental Matters

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

To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2008, in excess of the level currently included in Virginia jurisdictional rates, our results of operations could decrease. After that date, we may seek recovery through rates.

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

Notes to Consolidated Financial Statements, Continued

their insurance companies. As a result, we may be responsible for the costs of remedial investigation and actions under the Superfund Act or other laws or regulations regarding the remediation of waste. We do not believe that any currently identified sites will result in significant liabilities.

Nuclear Operations

Nuclear Decommissioning Minimum Financial Assurance

The 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 2007 calculation for the 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 nuclear decommissioning 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 liability protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to $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 power station (North Anna) and Surry power station) 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 $51 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, 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 Department of Energy (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 requesting damages in connection with its failure to commence accepting spent nuclear fuel. Trial is scheduled for May 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 power station. 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 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. We and ODEC filed a notice of appeal to the Virginia Supreme Court and posted security to suspend execution of the judgment during the appeal. The Virginia Supreme Court ruled the order was not final and could not be appealed. The surety bond that was posted as security was released by the Circuit Court of Halifax County, Virginia. The matter is set for trial before the trial court on April 8, 2008, which should result in a final appealable order. We estimate the cumulative amount of the adjustment as of December 31, 2007 to be approximately $80 million, without interest, of which our share would be one half. 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, 2007, we had issued $17 million of guarantees primarily to support tax exempt debt issued through conduits. We had also purchased $26 million of surety bonds for various purposes, including providing workers compensation coverage. Under the terms of surety bonds, we are obligated to indemnify the respective surety bond company for any amounts paid.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at December 31, 2007, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

Status of Electric Regulation in Virginia

2007 Virginia Restructuring Act And Fuel Factor Amendments

On July 1, 2007, legislation amending the Virginia Electric Utility Restructuring Act (the Restructuring Act) and the fuel factor became effective, which significantly changes electricity regulation in Virginia. Prior to the Restructuring Act, our base rates in Virginia were capped at 1999 levels until December 2010. The Restructuring Act ends capped rates two years early, on December 31, 2008. After capped rates end, retail choice will be eliminated for all but individual retail customers with a demand of more than 5 Mw and non-residential retail customers who obtain Virginia Commission approval to aggregate their load to reach the 5 Mw threshold. Individual retail customers will be permitted to purchase renewable energy from competitive suppliers if the incumbent electric utility does not offer a renewable energy tariff. Also after the end of capped rates, the Virginia Commission will set our base rates under a modified cost-of-service model. Among other features, the new model provides for the Virginia Commission to:

- Initiate a base rate case during the first six months of 2009, reviewing the 2008 test year, as a result of which the Virginia Commission:
  - shall establish a return on equity (ROE) no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earnings more than 50 basis points below the established ROE; or
  - may reduce rates prospectively upon completion of the 2009 review or, alternatively, order a credit to customers if we are found to have test year earnings of more than 50 basis points above the established ROE.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
  - shall establish an ROE no lower than that reported by at least a majority of a group of utilities within the southeastern U.S., with certain limitations, as described in the legislation;
  - may increase or decrease the ROE by up to 100 basis points based on generating plant performance, customer service and operating efficiency, if appropriate;
  - after 2010, authorize an increased ROE on overall rate base upon achieving the goals established for renewable energy portfolio standard programs. Such increased ROE would be in lieu of any increased or decreased ROE from the preceding paragraph, unless there has been an increase to the ROE awarded under the preceding paragraph that is higher than the renewable energy portfolio standard increase; and
  - shall increase base rates, if needed, to allow the Company the opportunity to recover its costs and earn a fair rate of return if we are found to have earned, during the test period, more than 50 basis points below the then currently established ROE; or
  - may order a credit to customers if we are found to have earned, during the test period, more than 50 basis points above the then currently established ROE, and reduce rates if we are found to have such excess earnings during two consecutive biennial review periods.
- 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 and energy efficiency, conservation and renewable energy programs; and
- Authorize an enhanced ROE on new capital expenditures as a financial incentive for construction of certain major generation projects.

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

As discussed previously, the legislation provides for the Virginia Commission to initiate a base rate case during the first six months of 2009, as a result of which the Virginia Commission may reduce rates or alternatively, order a credit to customers if we are found to have earnings more than 50 basis points above the established ROE. We are unable to predict the outcome of future rate actions at this time, however an unfavorable outcome could adversely affect our results of operations.

Virginia Fuel Expenses

Under amendments to the Virginia fuel cost recovery statute passed in 2004, our fuel factor provisions were frozen until July 1, 2007. Fuel prices have increased considerably since 2004, which resulted in our fuel expenses being significantly in excess of our fuel cost recovery. Pursuant to the 2007 amendments to the fuel cost recovery statute, annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were re-instituted on July 1, 2007. While the 2007 amendments did not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor was adjusted,

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this mechanism ensures dollar for dollar recovery for prudently incurred fuel costs.

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

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. In the past, 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. Capped electric retail rates provided an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs was subject to numerous risks even in the capped-rate environment. Those risks included, 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. However, with the return to a modified cost-of-service rate model under the 2007 Virginia Restructuring Act Amendments, our exposure to potential stranded costs and the risk of non-recovery will be eliminated.

North Carolina Regulation

In 2004, the North Carolina Utilities Commission (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 annual reduction in current base rates and a five-year base-rate moratorium, effective as of April 2005. Fuel rates are still subject to change under the annual fuel cost adjustment proceedings.

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,	**2007**		2006	
(millions)	**Carrying Amount**	**Estimated Fair Value[1]**	Carrying Amount	Estimated Fair Value[1]
Long-term debt[2]	**$ 5,190**	**$ 5,209**	$ 4,254	$ 4,236

Junior subordinated notes payable to affiliated trust	**412**	**402**	412	422
Note payable to Dominion			220	236

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

(2) Includes securities due within one year and amounts which represent the valuation of certain fair value hedges associated with our fixed-rate debt.

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, 2007 provision for credit losses, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

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

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit 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, 2007, our gross credit exposure totaled $32 million. Of this amount, investment grade counterparties, including those internally rated, represented 92% with 41% related to a single counterparty. We held no collateral for these transactions at December 31, 2007.

NOTE 24. RELATED-PARTY TRANSACTIONS

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

Transactions with Affiliates

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

DRS provides accounting, legal and certain administrative and technical services to us. In addition, 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.

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31, (millions)	**2007**	2006	2005
Commodity purchases from affiliates	**$ 373**	$ 234	$ 364
Services provided by affiliates	**345**	311	292
Services provided to affiliates	**25**	26	26

In 2007, we purchased two gas-fired turbines from an unregulated affiliate for $53 million as part of a 300 Mw expansion at our Ladysmith power station (Units 3 and 4) to supply electricity during periods of peak demand. We expect to purchase additional gas-fired turbines from this affiliate in the future, subject to approval by the Virginia Commission, as part of our continued capacity expansion plan.

We lease an office building from Dominion under an agreement that was to expire in 2008. In August 2007, we exercised our option to extend the lease term for five years. The original lease agreement is accounted for as a capital lease, with capitalized cost of the property under the lease, net of accumulated amor-

tization, of approximately $1 million and $3 million at December 31, 2007 and 2006, respectively. The rental payments for this lease were $3 million each in 2007, 2006 and 2005.

We have borrowed funds from Dominion under both short-term and long-term borrowing arrangements. At December 31, 2007 and 2006, our nonregulated subsidiaries had outstanding borrowings, net of repayments, under the Dominion money pool of $114 million and $140 million, respectively. At December 31, 2006, our borrowings from Dominion under a long- term note totaled $220 million. In December 2007, we recorded contributed capital of $220 million reflecting the conversion of this long-term note payable to equity. We incurred interest charges related to our borrowings from Dominion of $27 million, $10 million and $9 million in 2007, 2006 and 2005, respectively.

NOTE 25. OPERATING SEGMENTS

As a result of a fourth quarter 2007 segment realignment, the nature and composition of our primary operating segments have changed to reflect the creation of a new DVP segment which combined the operations previously included in the Delivery and Energy segments. All segment information for prior years has been recast to conform to the new segment structure.

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

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

Generation includes our regulated generation and energy supply operations.

Corporate and Other 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 are not included in profit measures evaluated by executive management, in assessing the segments performance or allocating resources among the segments, including the discontinued operations of VPEM prior to its transfer to Dominion.

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

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

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Notes to Consolidated Financial Statements, Continued

In 2005, the Corporate and Other segment included $58 million of net after-tax expenses attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following items attributable to Generation:

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

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	DVP	Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2007					
Operating revenue	**$ 1,467**	**$ 4,709**	**$ 5**	**$**	**$ 6,181**
Depreciation and amortization	**299**	**254**	**15**		**568**
Interest income	**6**	**9**	**8**	**(7)**	**16**
Interest and related charges	**133**	**174**	**3**	**(6)**	**304**
Income tax expense (benefit)	**212**	**166**	**(7)**		**371**
Extraordinary item, net of tax			**(158)**		**(158)**
Net income (loss)	**342**	**276**	**(170)**		**448**
Capital expenditures	**559**	**736**			**1,295**
Total assets	**7,708**	**10,516**		**(1,167)**	**17,057**
2006					
Operating revenue	$ 1,396	$ 4,202	$ 5	$	$ 5,603
Depreciation and amortization	293	225	18		536
Interest income	4	32	8	(6)	38
Interest and related charges	129	173		(6)	296
Income tax expense (benefit)	212	80	(8)		284
Net income (loss)	339	151	(12)		478
Capital expenditures	524	523			1,047
Total assets	7,048	9,250		(615)	15,683
2005					
Operating revenue	$ 1,395	$ 4,309	$ 8	$	$ 5,712
Depreciation and amortization	279	227	21		527
Interest income	1	33	7	(5)	36
Interest and related charges	145	181	1	(5)	322
Income tax expense (benefit)	218	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)	364	175	(529)		10

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NOTE 26. QUARTERLY FINANCIAL DATA (UNAUDITED)

A summary of our quarterly results of operations for the years ended December 31, 2007 and 2006 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
2007					
Operating revenue	**$ 1,443**	**$ 1,424**	**$ 1,833**	**$ 1,481**	**$ 6,181**
Income from operations	**181**	**191**	**582**	**272**	**1,226**
Extraordinary item, net of tax		**(158)**			**(158)**
Net income (loss)	**89**	**(79)**	**322**	**116**	**448**
Balance available for common stock	**85**	**(83)**	**318**	**112**	**432**
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

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

Third and fourth quarter results reflect the reapplication of deferral accounting for Virginia jurisdiction fuel costs beginning July 1, 2007.

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

None.

Item 9A(T). Controls and Procedures

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

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require our 2007 Annual Report to contain a management s report regarding the effectiveness of internal control. As a basis for our report, we tested and evaluated the design and operating effectiveness of internal controls. Based on our assessment as of December 31, 2007, we make the following assertion:

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

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

We evaluated our internal control over financial reporting as of December 31, 2007. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Virginia Power maintained effective internal control over financial reporting as of December 31, 2007.

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

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

February 26, 2008

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 Director
Thomas F. Farrell, II (53)	Chairman of the Board of Directors and Chief Executive Officer (CEO) of VP from February 2006 to date; Chairman of the Board of Directors of Dominion Resources, Inc. (DRI) from April 2007 to date; President and CEO of DRI from January 2006 to date; Chairman of the Board of Directors, President and CEO of Consolidated Natural Gas Company (CNG) from January 2006 to June 2007; Director of DRI from March 2005 to April 2007; 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.	1999
Thomas N. Chewning (62)	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 June 2007.	1999
Steven A. Rogers (46)	President and Chief Administrative Officer (CAO) of Dominion Resources Services, Inc. (DRS) and Senior Vice President and CAO of DRI from October 2007 to date; Senior Vice President and Chief Accounting Officer of DRI and VP from January 2007 to September 2007 and CNG from January 2007 to June 2007; Senior Vice President and Controller of DRI and CNG from April 2006 to December 2006; Senior Vice President (Principal Accounting Officer) (PAO) of VP from April 2006 to December 2006; Vice President and Controller of DRI and CNG and Vice President and PAO of VP from June 2000 to April 2006.	2007

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 or DRI. Our Board of Directors has determined that Thomas F. Farrell, II, Thomas N. Chewning and Steven A. Rogers are audit committee financial experts as defined by the SEC. As executive officers of the Company and/or DRI, Thomas F. Farrell, II, Thomas N. Chewning and Steven A. Rogers 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 (53)	Chairman of the Board of Directors and CEO of VP from February 2006 to date; Chairman of the Board of Directors of DRI from April 2007 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 June 2007; Director of DRI from March 2005 to April 2007; 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.

Thomas N. Chewning (62)	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 June 2007.
Jay L. Johnson (61)	President and COO Dominion Virginia Power of VP from October 2007 to date; Executive Vice President of DRI from December 2002 to date and of CNG from December 2002 to June 2007; President and COO Delivery of VP from February 2006 to September 2007; President and CEO of VP from December 2002 to January 2006.
Mark F. McGettrick (50)	President and COO Generation of VP from February 2006 to date; Executive Vice President of DRI from April 2006 to date; President and CEO Generation of VP from January 2003 to January 2006.
David A. Christian (53)	President and Chief Nuclear Officer (CNO) of VP from October 2007 to date; Senior Vice President Nuclear Operations and CNO of VP from April 2000 to September 2007.
Thomas P. Wohlfarth (47)	Senior Vice President and Chief Accounting Officer of VP, DRI and DRS from October 2007 to date; Vice President Budgeting, Forecasting & Investor Relations of DRS from February 2006 to September 2007; Vice President Financial Management of VP from January 2004 to January 2006; Director of Investor Relations of DRS from February 2000 to December 2003.

Any service listed for DRI, 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.

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, Chewning and Rogers. Messrs. Farrell and Chewning are not independent because they are executive officers of the Company. Mr. Rogers is not deemed independent because of his employment with Dominion. 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 which retained the consulting firm of Pearl Meyer & Partners (PM&P) to advise them on compensation matters. Our Board approves all compensation paid to executive officers based on Dominion s CGN Committee s recommendations. None of our directors, who are officers of the Company or Dominion, receive any compensation for the services they provide as directors.

Because Dominion s CGN Committee effectively administers one compensation program for all of Dominion, the following discussion and analysis is based on Dominion s overall compensation program.

EXECUTIVE COMPENSATION PHILOSOPHY THE OBJECTIVES OF THE 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 and benefits align management s financial success with that of its shareholders. Management and Dominion s Board of Directors, through the oversight of its CGN Committee, believe in providing competitive compensation and benefits to our officers, while putting a substantial portion of our senior executives overall compensation at risk based on their performance as compared to short and long-term goals established by the CGN Committee. Therefore, actual performance measured in comparison to targets will establish how competitive actual compensation will be for any given year.

The Process

Each year, Dominion and the CGN Committee conduct a comprehensive assessment and analysis of Dominion s compensation

program. The review process includes, but is not limited to, the following steps:

- A peer group of companies is defined and Dominion s stock and financial performance are benchmarked against these peers;
- 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 other relevant factors such as retention or market competitiveness concerns;

- The CEO meets with the CGN Committee to review succession plans for his position and for his senior officers;
- The current annual compensation of senior management and long-term compensation grants made over the past several years are reviewed;
- Appropriate performance metrics are considered and discussed along with attributes of annual and long-term programs for the next year;
- The entirety of the compensation program is considered and specific benefits and perquisites are reviewed periodically;
- Base pay, annual incentive pay, long-term pay and total compensation for individual officers are benchmarked against appropriate survey data;
- For top officers, if compensation information is available for their positions at a number of Dominion s peer companies, a blend of survey data and peer compensation data is used, as Dominion competes for talent not only in its own market, but also nationally and across industries;
- The compensation practices of Dominion s peer companies are reviewed, including their practices with respect to equity and other grants, benefits and perquisites; and
- Management s stock ownership and policies regarding Dominion stock ownership are reviewed.

Factors in Setting Compensation

While Dominion benchmarks and compares general compensation levels relative to Dominion s peer group of companies and market data for each position, its program is administered to meet the needs and requirements of Dominion rather than only matching pre-set market levels for each component. Dominion takes into consideration several factors in setting compensation, including:

- an officer s experience and job performance;
- the scope of responsibility for a position;
- the relative importance of a particular position to Dominion s strategy and success, and comparability to other positions at Dominion;
- retention and market competitive concerns; and
- the officer s role in any succession plan for other key positions.

Other factors may be considered. For example, when officers in different business units share similar job responsibilities, we consider their compensation both (i) as a group by discipline, and (ii) within their own individual business unit based on the revenue scope, competitiveness and strategic fit of that unit. Rotational assignments may also be a factor. When an officer is put in a position for leadership development or professional development reasons, the compensation for that officer will not necessarily be tied to the rotational position s market information, but based on the overall career path for the officer.

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CEO Compensation Relative to Other Named Executive Officers

Mr. Farrell participates in the same compensation programs and receives compensation based on the same philosophy and factors as other named executive officers. By applying the same philosophy and factors to Mr. Farrell, his overall compensation is significantly higher than the compensation of the named executive officers. His compensation is commensurate with the market competitiveness of his position, his greater responsibilities and decision-making authority, broader scope of duties that encompass the entirety of Dominion (as compared to the other named executive officers who are responsible for significant but distinct areas within Dominion), and his overall responsibility for the corporate strategy, board leadership, and the role of chief representative to shareholders, investors, regulators and the media.

Dominion considers CEO compensation trends versus the next highest paid officer and top officers as a group over a multi-year period to monitor the ratio of Mr. Farrell s pay relative to the pay of his senior officers based on (i) salary only and (ii) total direct compensation, including annual and long-term incentive pay. Dominion compares ratios to that of its peers to confirm that ratios are not out of line with practices at peer companies. There is no particular ratio or goal, but instead the CGN Committee considers year-over-year trends and comparisons with peers.

Management s Role in Our Process

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 its industry and the companies used by Dominion analysts and external analysts for comparison purposes. Our CFO and the CGN Committee s independent compensation consultant review and comment on the proposed group before it is submitted to the CGN Committee for approval.
- Dominion s CFO and CEO are both involved in establishing and recommending to the CGN Committee financial goals for the incentive programs based on management s internal goals and strategic plans.
- Dominion s CEO reviews market data, peer data and other information provided by Dominion s executive compensation department and the CGN Committee s independent compensation consultant regarding salaries, annual and long-term incentive targets for all officers, and plan amendments and design before recommendations are made to the CGN Committee.
- Dominion s CEO reviews and makes recommendations for all officers after considering and discussing with the CGN Committee the relevant factors used in setting each officer s compensation, but he does not make any recommendations or review proposals with regard to his own compensation; the CGN Committee has the exclusive authority to approve compensation for Dominion s senior executives other than the CEO. The CGN Committee makes recommendations to the independent members of the Board of Directors, who have final approval of CEO compensation.
- Dominion s CEO makes recommendations to the CGN Committee regarding the timing and frequency of long-term programs, special arrangements to address specific retention concerns and the elimination or modification of certain benefits.
- The Governance Department coordinates data requests and the preparation of CGN meeting presentation and mailing materials with the independent compensation consultant, and as otherwise directed by the Chair of the CGN Committee.

The Independent Consultant s Role in Our Process

The independent consultant participates in CGN Committee meetings as requested by the Chairman of the Committee, either in person or by teleconference. When discussing CEO compensation or as otherwise requested, the consultant meets with the CGN Committee members in executive session without management present. The nature and scope of the PM&P consultant s assignment are as follows:

- To perform a detailed review of the base salary, bonus potential and value of long-term incentives for each of the senior officers as compared to the appropriate comparable positions at peer companies, and as compared to survey data for comparable positions at similarly sized companies, and to provide a full report to the CGN Committee on her findings;
- To participate in the selection of peer companies, providing independent advice to the CGN Committee on the appropriateness of the peer group and the process used to select such peer group;
- To participate in CGN Committee executive sessions without management present to discuss CEO compensation and any other relevant matters; and
- To generally review and offer advice to the CGN Committee regarding other aspects of the executive compensation program, including special projects, plan design, best practices and other matters as requested by or on behalf of the CGN Committee.

The compensation consultant does not provide any other services to Dominion outside of this advice and counsel to the CGN Committee on executive and director compensation matters.

How We Use Survey Data

Dominion uses both broad-based survey data and surveys that have job-specific market data whenever possible to benchmark the components of base pay, annual incentive pay, long-term pay and total compensation. Dominion benchmarks each officer s position against one or more appropriate job matches from the surveys, based on primary job responsibilities and the scope of the position, which is typically based on revenue or asset size, and in some circumstances, on number of employees.

Dominion purchases broad-based surveys from several vendors, including Mercer HR Consulting, Hewitt, Towers Perrin and other organizations. Dominion also purchases industry specific surveys whenever possible, including surveys provided by the American Gas Association, ECI Oil & Gas, ORC Natural Gas, Towers Energy, Mercer Energy, and Mercer Energy 27.

Dominion does not analyze compensation practices of the individual companies that may participate in these surveys, and does not benchmark its financial performance against any of the survey populations. Dominion does benchmark the financial performance against peer companies as part of the annual compensation setting process, as described under *Our Process* and under *The Peer Group and Peer Group Comparisons.*

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The Peer Group and Peer Group Comparisons

Dominion uses peer company data to: (i) compare Dominion s stock and financial performance against its peers using a number of different metrics and time periods; (ii) analyze compensation practices within its industry; (iii) benchmark base pay, annual incentive pay, long-term compensation and total compensation; and (iv) benchmark other benefits such as its Employment Continuity Agreements and the use of long-term equity incentives.

Dominion s peer group is generally consistent from year to year, with merger and acquisition activity being the primary reason for any changes. The 2007 peer group consisted of a diversified group of thirteen energy companies:

American Electric Power Company, Inc.	Nisource, Inc.
Constellation Energy Group, Inc.	PPL Corporation
Duke Energy Corporation	Progress Energy, Inc.
Entergy Corporation	Public Service Enterprise Group
Exelon Corporation	Southern Company
First Energy Corporation	TXU Corp.
FPL Group, Inc.	

Elements and Analysis of Dominion s Compensation Program

Dominion s 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. Annual increases achieve two primary purposes: (i) an annual adjustment to keep salaries in line and competitive with the market and to reflect changes in responsibility, including promotions; and (ii) a motivational tool to acknowledge and reward excellent individual performance, special skills, experience and other relevant considerations.

While the base salary component of Dominion s program generally is targeted at or slightly above market median, the primary goal is to compensate executives at a level that best achieves Dominion s compensation philosophy, whether or not this results in actual pay for some positions that may be higher or lower than its stated target. Dominion has found that proxy and survey results for particular positions can vary greatly from year to year, so market trends are considered for certain positions over a period of years rather than a one-year period in setting compensation for such positions.

For 2007 base compensation, all officers received a base salary adjustment of at least 4%. Certain officers received salary adjustments in excess of 4% for one of the following reasons: (i) increase or other change in job responsibility; (ii) market-based reasons; or (iii) based on one or more of the factors in setting compensation described in *Factors in Setting Compensation* above.

CEO Base Salary: Mr. Farrell received a 10% increase in base salary in 2007. This increase moved his base salary closer to the median for his peers. When Mr. Farrell was promoted to the position of President and Chief Executive Officer of Dominion in January 2006, the CGN Committee determined it would bring him to market median over the course of a few years, based on his achievements and performance in office. The Committee consid-

ered Mr. Farrell s performance and the complexity of his job in approving his 2007 increase.

Base Salaries for Other Named Executive Officers: The other named executives salaries increased in 2007 by the following amounts: Mr. Chewning 7.0%; Mr. McGettrick 8.0%; Mr. Johnson 7.0%. Mr. Christian s salary was increased 6.0% effective January 1, 2007. When he assumed the duties of President Dominion Nuclear effective October 1, 2007, his salary was increased an additional 5.0%. For these officers, in addition to the market benchmarks for compensation for their positions, individual performance and scope and complexity of their positions relative to other positions at Dominion were considerations in setting 2007 compensation, including salaries. For Messrs. McGettrick and Christian, consideration was given to the increasing size, complexity and competitiveness of the business unit for which each of them is responsible.

Performance-Based Compensation

For our CEO, just over 50% of his 2007 targeted compensation (annual and long-term) is at risk and is dependent on the achievement of performance goals. For the other named executive officers, 2007 targeted compensation at risk ranges from 45% to 50%, and for a typical vice president, the percentage of targeted compensation at risk for 2007 is approximately 37%. This compares to an average of approximately 11% of total pay at risk for non-officer employees. This structure ensures that officers will have compensation that could be significantly lower than market median if performance goals are not achieved, depending on the extent that goals are missed. If performance goals are exceeded, officers will receive compensation that is closer to or even exceeding the market 75th percentile, depending on the extent that goals are exceeded and each particular officer s compensation position relative to the market.

Additionally, a substantial portion of each officer s total compensation is tied to the performance of Dominion s stock through restricted stock grants, ranging from 17% of targeted total compensation for a typical vice president up to 36% for Mr. Farrell. For Mr. Farrell, this means that almost 90% of his total direct compensation is stock-based or has 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.

The Annual Incentive Program

Overview

The annual incentive program continues to play a critical role in Dominion s compensation practices and its philosophy of aligning the interests of Dominion s 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. All non-union employees scheduled to work 1,000 hours or more in a calendar year and union employees covered under collective bargaining agreements that provide for participation in their company s incentive plan are eligible for annual incentive bonus payments.

The annual incentive program is designed to:

- Tie interests of shareholders and employees closely together;

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Focus Dominions workforce on company, operating group, team and/or individual goals that ultimately influence financial results;
Reward corporate and operating group earnings performance;
Reward operational, stewardship, and Six Sigma cost savings success;
Emphasize teamwork by focusing on common goals; and
Provide a competitive total compensation opportunity.

Target Awards

Target bonus awards are determined as a percentage of an executive s annualized base salary as of December 31 for the plan year (for example, 45% of base salary). The target award is the amount of cash that will be paid if an executive achieves a score of 100% for the goals established at the beginning of the year, and the plan is funded at the threshold funding target set for the year. The target bonus awards under the Annual Incentive Plan established each year are generally designed so that the executive s total cash compensation for the year will be at or slightly above market median if the plan goals are achieved or exceeded. 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 are not achieved.

For the 2007 Annual Incentive Plan (the 2007 AIP), Mr. Farrell s annual incentive target was 120% of his base salary, consistent with Dominion s intent to have a significant portion of his compensation at risk. His annual incentive plan target was increased from 110% to 120% of base salary for 2007 in an effort to move his targeted total cash compensation closer to market median. The 2007 AIP targets for the other named executive officers as a percentage of base salary were: Mr. Chewning 95%; Mr. McGettrick 95%; Mr. Johnson 85%; and Mr. Christian 70%.

Funding of the 2007 AIP

Funding for the 2007 AIP was based solely on Dominion s consolidated operating earnings for officers. For non-officers, 25% funding was guaranteed, with 75% of the funding based on consolidated operating earnings. This created the potential for incentive payouts for non-officers even if Dominion did not reach its consolidated operating earnings threshold so as to reward employees for operational excellence during the year.

The consolidated operating earnings goal is designed to drive employee behavior and performance to achieve management s consolidated operating earnings goals for Dominion for that fiscal year. The goal is designed to ensure that shareholders are receiving an appropriate return on their investment in Dominion.

At the beginning of 2007, due to the uncertainty of 2007 earnings as a result of its pending E&P divestitures, Dominion set different funding goals for officers potentially subject to the deduction limits imposed by Internal Revenue Code Section 162(m) than the goals set for other officers and employees. For Dominion s named executive officers (which includes all of our named executive officers except for Mr. Christian), 2007 consolidated operating earnings of $1,198 million for Dominion would achieve target funding of the 2007 AIP, with funding increased by three percent for every $4.4 million in consolidated operating earnings achieved above the full funding target, up to a maximum funding level of 200%. For other officers (including Mr. Christian) and employees, the 2007 AIP had a full funding

target of $1,626 million in Dominion s consolidated operating earnings, with a maximum of 200% funding based on a formula that provides equal sharing of consolidated operating earnings between plan participants and shareholders up to the maximum plan funding.

Full funding means that the plan is 100% funded, and participants can receive their full targeted AIP payout if they achieve 100% score for their particular goal package, as described below under *How We Determine AIP Payout Scores*. At the maximum plan funding level of 200%, participants can earn up to two times their targeted AIP payout.

Dominion reported consolidated operating earnings of $1,678 million for 2007 as compared to reported GAAP earnings of $2,539 million. Consolidated operating earnings are Dominion s reported earnings determined in accordance with GAAP, adjusted for certain items. This level of operating earnings resulted in each of Dominion s named executive officers (which includes all of our named executive officers except for Mr. Christian) earning 200% funding and other officers and employees earning 182% funding. However, the CGN Committee exercised negative discretion and approved 182% funding for these named executive officers (which includes all of our named executive officers except for Mr. Christian), consistent with all other plan participants.

How We Determine AIP Payout Scores

Officers other than Dominion s named executive officers must meet certain payout goals, including a consolidated operating earnings goal that is the same as the AIP funding goal described above, business unit financial goals, operating and stewardship goals, and Six Sigma goals, in order to earn all or a portion of their funded AIP payout. The percentage achievement of the payout goals determines how much of an officers funded payout will be earned up to 100%.

Business unit financial goals are set based on the levels necessary to achieve the consolidated earnings goal for Dominion. Breaking the consolidated goal into smaller goals for each business unit provides line-of-sight goals for officers and employees, and facilitates financial and business planning.

The business unit operating and stewardship goals are designed to provide line-of-sight goals that may not be financial and that can be customized for the business unit or individual. Goals such as safety, outage targets for power plants, and capital spending goals are some examples. The accomplishment of these goals often supports the business unit financial goals or focuses on other key areas such as safety and customer service. The most common operating and stewardship goals have objectives in the following areas: safety; reliability; expenditures and production; forced outages; and service level requirements.

Six Sigma goals support Dominion s mission to continue to use a Six Sigma business process improvement program. The Six Sigma program uses data and statistical analysis to measure and improve Dominion s operational performance, practices and systems. Six Sigma projects are designed to increase productivity, reduce costs and enhance customer service. Six Sigma targets are based on the positive financial impact of projects utilizing these Six Sigma goals and methodology.

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Each executive s goals are weighted according to his or her responsibilities. The overall goal score cannot exceed 100%. The goal weightings for bonuses under the 2007 AIP are as follows:

	Consolidated Financial Goal	Business Unit Financial Goals	Operating/ Stewardship	Six Sigma
CEO/CFO	90%			10%
Other Officers	25%	50%	15%	10%

For Dominion s named executive officers (which includes all of our named executive officers except for Mr. Christian), AIP payouts are earned on their funding goals only. Therefore, at 182% funding, each named executive officer is entitled to an AIP payout of 182% of his or her target award. The goal percentages serve as guidelines for the CGN Committee to consider in exercising negative discretion to lower the AIP payout for the named executive officers if deemed appropriate. Negative discretion can be exercised based on several factors. To promote consistency among Dominion s named executive officers and other officers, the CGN Committee in 2007 specifically considered, for the CEO and CFO, the level of achievement of the corporate Six Sigma goal, and for the other named executive officers, the achievement of the business unit financial, operating and stewardship, and Six Sigma goals, up to the percentages indicated for each goal. The Committee exercised negative discretion for Mr. McGettrick, as described in *2007 AIP Payouts* below.

2007 AIP Payouts

The formula for calculating an award is:

Base Salary x Target Award Percentage x Funding Percentage x Total Payout Goal Score = Actual Award

As an example, the payout for an officer with a base salary of $200,000, an annual incentive target of 45% and a 2007 total payout goal score of 95% due to an operating and stewardship goal shortfall would be determined as follows, based on the approved 182% level of funding:

$200,000 (salary) x 45% (target award) x 182% (level of funding) x 95% (total payout goal score) = $155,610 payout.

The consolidated operating earnings goals and goal achievement are described above under *Funding of the 2007 AIP*. The Company s applicable business unit financial goals and performance of such goals were as follows:

Company	Threshold (Net Income) (million/$)	100% Payout (Net Income) (million/$)	2007 (Net Income) (million/$)	2007% Accomplishment
Dominion Delivery	$ 383	$ 395	$ 415	100%
Dominion Generation	$ 678	$ 703	$ 756	100%

The Six Sigma goal for 2007 was a Dominion-wide positive financial impact of at least $85 million. If the positive financial impact was $120 million or more, a 4% credit was granted that could be applied to offset any shortfall in operating and stewardship goals other than goals based on safety and regulatory compliance. Each of the business units had individual goals as well as a shared goal, all aimed at reaching the corporate-wide goal. Each business unit achieved its individual goals. The Six Sigma positive financial impact exceeded $120 million, resulting in all employees earning the 4% extra credit, which was applied to offset any operating and stewardship goal shortfalls other than goals based on safety and regulatory compliance.

Each business unit scores its own operating and stewardship goals and Mr. Farrell reviews the scores for each officer. The general categories of operating and stewardship goals in 2007 for the named executive officers other than Mr. Farrell and Mr. Chewning were as follows: safety; emergency response, response to power outages, environmental, legal and regulatory compliance, system reliability, costs and expenditures, supplier diversity and risk management.

Based on a missed safety goal in the Generation business unit, the CGN Committee exercised negative discretion and lowered Mr. McGettrick s payout score to 96.3%. Our other named executive officers were paid out based on a 100% payout score.

Actual amounts earned under the 2007 AIP by named executive officers are set forth in the Summary Compensation Table under the Non-Equity Incentive Plan Compensation column.

The Long-Term Incentive Program

The long-term incentive program focuses on longer-term goals and retention, with annual grants typically made at the beginning of the second quarter of the year. Dominion does not time the grant dates based on any release of material information or expectations of stock price changes. Newly-promoted officers of Dominion receive pro-rated grants for the current year s program.

Fifty percent of our long-term program is in the form of restricted Dominion stock grants, which are not performance-based. The other 50% of the program is in the form of either cash-based performance grants or, for Dominion officers who have not achieved at least 50% of their stock ownership requirements, goal-based stock. Dominion has not issued any stock options since 2002.

Although the CGN Committee reviews prior grants to the CEO before approving new long-term grants, the determination of the appropriate grant for the CEO in any given year is based on the results of the process we described above for our executive compensation program. The fact that an executive received long-term incentive awards over the course of his or her career is not a significant factor in determining appropriate long-term incentive awards in the current year, although the CGN Committee does consider prior awards. Similarly, if a newer executive does not have prior grants outstanding due to his or her short tenure, compensation paid to such executive is not increased due to a lack of outstanding grants from prior years.

2007 Restricted Stock Grants

Restricted stock grants serve as a retention tool and align the interests of Dominion officers with the interests of Dominion shareholders. All officers received a restricted Dominion stock grant on April 3, 2007 based on a stated dollar value. The number of shares awarded was determined by dividing the stated dollar value by the fair market value (average of high and low) of Dominion s common stock on April 2, 2007. The grants have a three-year vesting term, with cliff vesting at the end of the restricted period on April 3, 2010. Upon vesting, all officers are expected to hold any vested shares, net of shares used to cover taxes.

The fair value of each named executive officer s 2007 restricted stock grant is disclosed in the Grants of Plan-Based Awards table.

2007 Performance Grants

All Dominion officers received performance grants on April 3, 2007. For officers who had achieved targeted share ownership, the performance grants were for a stated target dollar amount. The

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CGN Committee believes cash-based performance grants are appropriate because of: (i) the significant ownership of Dominion stock by many executives and the high rate of compliance with Dominion s share ownership guidelines; (ii) the belief that a cash-based program will increase the motivation of officers to achieve the goals included in the long-term incentive plan, as the rewards from the plan will be more immediate; (iii) the fact that officers typically hold net shares from vesting restricted stock grants until retirement; and (iv) the efficiency of such awards from a tax standpoint, as no shares need to be sold to pay taxes, and any net cash award can be used to pay taxes on any vesting restricted stock awards.

Officers who have not achieved at least 50% of targeted share ownership received goal-based Dominion stock grants based on a stated dollar value. The number of Dominion shares awarded was determined by dividing the stated dollar value by the fair market value of Dominion s common stock on April 2, 2007. All officers are expected to hold any vested shares, net of shares used to cover taxes.

The 2007 performance grants are denominated as a target award, with actual payout equal to 0-200% of the target based on Dominion s performance against two metrics:

Total Shareholder Return (TSR) for the two-year period ended December 31, 2008 relative to the TSR of a group of industry peers selected by the CGN Committee. TSR is the difference between the value of a share of Dominion common stock at the beginning and end of the performance period, plus dividends paid as if reinvested in Dominion stock. The Peer Group for this grant is the same as the Peer Group used for 2007 compensation setting, with the exception of TXU Corp. TXU Corp., which was part of Dominion s peer group for 2007 compensation-setting purposes, was excluded as a peer company for the 2007 long-term awards because it announced its plans to become privately-held in 2007.

Return on Invested Capital (ROIC) for the two-year period ended December 31, 2008. ROIC reflects Dominion s total return divided by average invested capital for the performance period. For this purpose, total return is Dominion s consolidated operating earnings plus its after-tax interest and related charges, plus preferred dividends.

The performance period commenced on January 1, 2007 and will end on December 31, 2008. Each metric is equally weighted such that TSR performance shall determine 50% of the target amount and ROIC performance will determine the other 50% of the target amount.

Payouts for all officers, including officers who retire before the end of the performance period (who receive a pro-rata payout amount after the end of the performance period), will be made in February 2009.

The TSR Goal

The portion of the TSR target amount that will be paid out, if any, is based on the following table:

Relative TSR Performance	Percentage Payout of TSR Percentage*
Top Quartile - 75% to 100%	150% - 200%
2nd Quartile - 50% to 74.9%	100% - 149.9%
3rd Quartile - 25% to 49.9%	50% - 99.9%
4th Quartile - below 25%	0%

* *TSR weighting is interpolated between the top and bottom of the percentages for that Quartile.*

The ROIC Goal

For the 2007 performance grants made to officers and employees (other than Dominion s Section 16 officers), the CGN Committee approved the following ROIC goals, as modified in 2008 to reflect the 2007 budget as adjusted for Dominion s E&P divestitures, and for the approved 2008 budget. The ROIC targets and corresponding payout scores are as follows:

ROIC Performance	Percentage Payout of ROIC Percentage
8.5% or greater	200%
8.3% - 8.49%	150% - 199.9%
8.1% - 8.29%	100% - 149.9%
7.9% - 8.09%	50% - 99.9%
Below 7.0%	0%

Because of the uncertainty with Dominion s pending E&P divestitures in 2007, Dominion s Section 16 officers, which include our named executive officers, were given awards with ROIC percentages based on a 2007 budget that excluded any assumed earnings from the E&P business unit. In order to preserve Dominion s ability to deduct performance-based compensation paid to officers potentially subject to the deduction limits imposed by Internal Revenue Code Section 162(m), the CGN Committee does not have the discretion to modify the ROIC goals for Dominion s Section 16 officers based on budget adjustments for E&P divestitures, the approved 2008 budget or other factors.

Although the CGN Committee does not have the discretion to modify the ROIC goals for the named executive officers, it may exercise negative discretion to lower their payout amounts to be consistent with the payout for other officers.

The ROIC portion of the 2007 grants for our Section 16 officers is based on the following table:

ROIC Performance	Percentage Payout of ROIC Percentage
5.9% or greater	200%
5.7% - 5.89%	150% - 199.9%
5.5% - 5.69%	100% - 149.9%
5.3% - 5.49%	50% - 99.9%
Below 5.3%	0%

Upon completion of the performance period, the CGN Committee will determine the extent to which the performance criteria have been met. Payment will be made (or in the case of goal-based stock awards, shares will be issued) on or before March 15, 2009. Possible payouts for the named executive officers are set forth in the Grants of Plan-Based Awards table.

Vesting Terms for the 2007 Restricted Stock Grants and Performance Grants

The grants are forfeited in their entirety if an 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 Dominion. In the case of retirement, pro-rated vesting will not occur unless the CEO determines the officer s retirement is not detrimental to the Company. For the performance grants, the payout is based on actual goal performance at the end of the performance cycle.

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In the event of a change in control of 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 terminated, any remaining unvested shares will vest as of the termination date. (See the Potential Payments Upon a Termination or Change in Control Table.) This is considered to be a modified double trigger. For the cash performance grants, because any goals will likely be materially changed as a result of any change in control, 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 financial statements as of the day before the change in control occurred.

Payout under 2006 Performance Grants

In February 2008, payouts were made to Dominion officers who received 2006 performance grants, including our named executive officers. Like the 2007 performance grants, the 2006 performance grants were based on two evenly-weighted goals: Total Shareholder Return relative to a peer group of companies (the TSR goal) and Return on Invested Capital (the ROIC goal).

The TSR goal performance payout was based on the same scale set forth above for the 2007 performance grants, but using a slightly different peer group of companies and based on a performance period of April 1, 2006 (when the grants were approved) through December 31, 2007. The companies in the peer group for the 2006 performance grant were:

American Electric Power Company, Inc.	Nisource, Inc.
Duke Energy Corporation	PPL Corporation
Entergy Corporation	Progress Energy, Inc.
Exelon Corporation	Southern Company
FirstEnergy Corporation	TXU Corp.
FPL Group, Inc.	

Revised ROIC goals for the 2006 grant were approved by the CGN Committee at the time it approved the payouts in January 2008 based on adjustments to the 2007 budget. The CGN Committee s discretionary authority to revise the ROIC goals was provided for under the terms of the grant. Because of Dominion s E&P divestitures, the CGN Committee lowered the targets based on the 2007 budget, as adjusted for the E&P sales. The revised targets were as follows:

ROIC Performance	Percent Payout of ROIC Percentage
7.8% or greater	200%
7.6% - 7.79%	150% - 199.9%
7.4% - 7.59%	100% - 149.9%
7.2% - 7.39%	50% - 99.9%
Below 7.2%	0%

The CGN Committee approved a 138% payout for the 2006 performance grants. Relative TSR performance was in the 2nd Quartile, resulting in 100% achievement for that goal. Based on the revised goal, ROIC performance for the two-year period ending on December 31, 2007 was 7.70%, resulting in a score of 176% for the ROIC goal. Applying a 50% weighting to each metric, the TSR goal achievement was 50% (100% x 50%) and the ROIC goal achievement was 88% (176% x 50%).

Employee and Executive Benefits

Our officers are eligible to participate in all of the employee benefit programs available to Dominion employees. The core benefit programs include two tax-qualified retirement plans, medical, dental, and vision benefit plans, a health savings account, health and dependent care flexible spending accounts, group-term life insurance, travel accident coverage, short-term disability and long-term disability coverage, and a paid time off program. There are other miscellaneous employee benefit programs, including employee assistance programs and employee leave policies.

Dominion sponsors two types of tax-qualified retirement plans in which our employees participate: a defined benefit pension plan (the Pension Plan) and a defined contribution 401(k) savings plan (the 401(k) Plan).

The Pension Plan is a traditional pension plan providing annuity benefits upon attainment of retirement age. The Pension Plan also has a cash balance component under which the company contributes a percentage of each participant s compensation to a special retirement account, which may be paid in a lump sum or added to the annuity benefit upon retirement. Pension benefits are paid under a formula explained in a note to the Pension Benefits table. The change in pension value for 2007 for named executive officers is included in the Summary Compensation Table.

Employees who contribute to the 401(k) Plan receive a matching contribution of 50 cents for each dollar contributed up to 6% of compensation (subject to IRS limits) if the employees have less than 20 years of service, and 67 cents for each dollar contributed up to 6% of compensation (subject to IRS limits) for employees with 20 or more years of service. The amount of the company matching contributions for the named executive officers ranged from $2,611 to $4,770, as shown in the All Other Compensation column on the Summary Compensation Table**.** Officers whose matching contributions were limited due to the compensation limit imposed under Internal Revenue Code Section 401(a)(17) ($225,000 for 2007) or the annual addition limit imposed under Internal Revenue Code Section 415 ($45,000 for 2007) received a cash payment in 2007 to make them whole for the company match lost as a result of the Internal Revenue Code limitation. The amount of lost company match cash payments made to the named executive officers ranged from $3,632 to $12,338. The company matching contributions to the 401(k) Plan and the cash payments of Company matching contributions above Internal Revenue Code limits for the named executive officers are included in the All Other Compensation column in the Summary Compensation Table and detailed in the footnote for that column.

Dominion also maintains two non-qualified retirement plans for executives, the Benefit Restoration Plan and the Executive Supplemental Retirement Plan, to provide a competitive level of benefits. 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 401(k) Plan alone will not produce the same percentage of replacement income in retirement for executives as for rank and file employees.

The Benefit Restoration Plan makes up for limits on Pension Plan benefits imposed by the Internal Revenue Code, as more fully explained in a note to the Pension Benefits Table. Like the Pension Plan, Benefit Restoration Plan benefits are actuarially determined under a formula that takes into account base salary,

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credited age, credited service, and a Social Security offset. To accommodate changes in tax law, the Dominion Benefit Restoration Plan was frozen as of December 31, 2004 and a New Benefit Restoration Plan was implemented effective January 1, 2005. There is no change in the benefit formula under the 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 a note to the Pension Benefit table. This Plan is intended to partially make up for the limits on benefits provided under the Pension Plan, 401(k) Plan, and Benefit Restoration Plan due to their use of only base salary in the benefit formulas. Because the Executive Supplemental Retirement Plan does not include long-term incentive compensation in its calculations, a significant portion of the potential compensation for executives is excluded from calculation in any retirement plan benefit. To accommodate changes in the tax law, the Executive Supplemental Retirement Plan was frozen as of December 31, 2004 and a New Executive Supplemental Retirement Plan was implemented effective January 1, 2005. There is no change in the benefit formula under the new plan.

Dominion may grant additional months of service and years of age to participants in the non-qualified retirement plans for mid-career recruiting and retention purposes. Mr. Farrell will be credited with 25 years of service when he attains age 55, and he will be credited with 30 years of service when he attains age 60. Mr. Chewning has been credited with 30 years of service. Mr. McGettrick has been credited with five years of service. Mr. Johnson will be credited with 20 years of service once he completes ten years of actual service. Additional age and years of service may be credited in certain situations pursuant to the terms of individual retirement agreements and arrangements for the named executive officers.

The present value of accumulated benefits under these plans is disclosed in the Pension Benefits table.

Dominion also maintains an Executive Life Insurance Program for executives. The plan provides for whole-life insurance policies to executives with a death benefit that is a multiple (one to three times) of an 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 makes premium payments until the later of 10 years or the date the executive attains age 64. Executives are taxed on the premiums paid by the company. The premiums for these policies are included in the All Other Compensation column of the Summary Compensation Table.

Perquisites

Dominion provides perquisites for executives that are in line with peer and other companies generally to remain competitive for talent with comparable employers. The CGN Committee annually reviews the perquisites to ensure they are an effective and efficient use of corporate resources. In addition to incidental perquisites associated with maintaining an office, Dominion offers the following perquisites to all officers:

1. An allowance of up to $9,500 a year to be used for health club memberships, comprehensive executive physicals, wellness programs, and financial and estate planning. Dominion wants
   executives to be proactive with preventive healthcare and also wants executives to use professional, independent financial and estate planning consultants to ensure proper tax reporting of company-provided compensation and to help executives optimize their use of Dominion s retirement and other employee benefit programs.
2. A company-leased vehicle, including the cost of insurance, gas and maintenance, up to an established lease-payment limit (if the lease payment exceeds the allowance, the officer pays for excess amounts on the vehicle personally).
3. In limited circumstances, use of Dominion s company aircraft for personal travel. For security reasons, Dominion s Board requires Mr. Farrell to use the aircraft for all travel, including personal travel. The use of company aircraft for personal travel by other executives is limited and usually related to (i) travel with the CEO or (ii) personal travel to accommodate business demands on the executives schedule. Dominion also transports spouses of executives to meetings that spouses are invited to attend. With the exception of Mr. Farrell, personal use of aircraft is not available when there is a business need for the aircraft. Use of Dominion s company aircraft saves substantial time and allows better access to executives for company purposes. Over 97% of the use of Dominion s company planes is for business purposes.

With the exception of executive physicals for preventive purposes, these perquisites are fully taxable to executives. Dominion provides a tax gross-up for personal use of the company plane by the senior executive officers and their immediate family members.

Other Agreements and Special Payments

As one of the nations largest producers and transporters of energy, Dominion is part of a consistently changing and increasingly competitive environment. In order to secure and retain the services and focus of key management executives, Dominion has entered into agreements with each of our named executive officers to provide certain retirement benefits or other protections in certain circumstances.

Under the terms of their employment agreements, Messrs. Farrell and Chewning will each become entitled to a payment of one times salary when they retire as consideration for their agreement not to compete with Dominion for a two-year period following their retirement.

If Mr. Farrell is involuntarily terminated without cause before he attains age 55, he will be entitled to participate in Dominion s retiree medical plan to the same extent as retired employees under the terms of the plan offered to retired employees as of his involuntary termination date. In addition, any unvested restricted stock granted to Mr. Farrell before 2006 would become vested on his involuntary termination date.

Under the terms of Mr. McGettrick s agreement, he will be credited with five years of service and age for purposes of computing his retirement benefits and eligibility for benefits under Dominion s retiree medical plan and retiree life insurance plan. If Mr. McGettrick terminates employment before he attains age 55, he will be deemed to have retired for purposes of determining his vesting credit under the terms of his restricted stock and performance grant awards.

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Under the terms of his agreement, Mr. Johnson s benefit under the Executive Supplemental Retirement Plan will be calculated as a life annuity (instead of a 10 year certain annuity) after he has completed 10 years of service with Dominion.

Under terms of his agreement, Mr. Christian s benefit under this Executive Supplemental Retirement Plan will be calculated as a life annuity if he remains employed with Dominion until the age of 60.

In addition, Dominion has entered into Employment Continuity Agreements with all executives to ensure continuity in the event of a change in control of Dominion. For purposes of the Employment Continuity Agreements, a change in control will occur 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. In determining the appropriate multiples of compensation and benefits payable upon a change in control, Dominion evaluated peer group and

general practices, and considered the levels of protection necessary to retain key officers in such situations.

The specific terms of the employment agreements for named executive officers and Employment Continuity Agreements for all officers are discussed in the *Potential Payments Upon Termination and Change in Control* section.

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 our CEO or any of the next four highly compensated executive officers named in the Summary Compensation Table. Certain performance-based compensation is specifically exempt from the deduction limit.

It is our intent to provide competitive executive compensation while maximizing our tax deduction. The CGN Committee considers the deduction limit imposed by Section 162(m) when designing annual and long-term compensation programs and approving payouts under such programs.

The CGN Committee reserves the right to approve, and in some cases has approved, non-deductible compensation if the Committee members believe it is in the company s best interest.

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Executive Compensation

SUMMARY COMPENSATION TABLE [1]

The following table represents information concerning compensation paid or earned by the named executive officers for the years ended December 31, 2007 and 2006.

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	**2007**	**517,000**	**1,246,504**	**3,074,928**	**1,028,323**	**298,803**	**6,165,558**
Chief Executive Officer	2006	350,000	686,742	408,100	915,719	196,025	2,556,586
Thomas N. Chewning	**2007**	**250,380**	**461,861**	**971,107**	**127,083**	**136,243**	**1,946,674**
Executive Vice President and CFO	2006	180,000	311,604	171,720	88,263	112,317	863,904
Mark F. McGettrick	**2007**	**300,510**	**318,074**	**939,197**	**414,335**	**87,950**	**2,060,066**
President & CEO Generation	2006	262,500	214,537	214,364	441,558	77,724	1,210,683
Jay L. Johnson	**2007**	**233,550**	**237,572**	**671,802**	**284,253**	**84,855**	**1,512,032**
CEO Dominion Virginia Power	2006	222,615	199,705	188,778	204,537	98,883	914,518
David A. Christian	**2007**	**235,908**	**149,465**	**526,972**	**188,455**	**64,818**	**1,165,618**
President & CNO Dominion Nuclear	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 reflect only the approximate portion related to their service for the Company in the year presented.*

(2) *The amounts in this column reflect the compensation expense recognized in 2007 on all outstanding stock awards in accordance with Statement of Financial Accounting Standards No. 123 (revised), Share-Base Payments (SFAS 123R). Dominion did not grant any options in 2007. The grant date fair value of restricted stock awards is equal to the market price of Dominion stock on the date of grant in accordance with SFAS 123R. The grant date fair value of each named executive officer s 2006 and 2007 restricted stock grant is disclosed in the Grants of Plan-Based Awards table. See also Note 21 to the Consolidated Financial Statements in Dominion s Annual 2007 Report on Form 10-K for more information on the valuation of stock-based awards and the Outstanding Equity Awards at Fiscal Year-End table for a listing of all outstanding equity awards as of December 31, 2007.*

(3) *The amounts in this column include the payout under Dominion s 2007 AIP and 2006 Performance Grant. All of the named executive officers except for Mr. McGettrick received the full potential payout of their target awards, reflecting 182% funding of the 2007 AIP and 100% payout for accomplishment of their goals. Mr. McGettrick s payout was reduced due to less than 100% performance on a safety goal. The payout amounts were as follows: Mr. Farrell $1,129,128; Mr. Chewning $432,907; Mr. McGettrick $500,357; Mr. Johnson $361,302; and Mr. Christian $311,692. See Compensation Discussion and Analysis for additional information on the 2007 AIP and the Grants of Plan Based Awards table for the range of each named executive officer s potential award under the 2007 AIP. Amounts in this column also include the payouts under the 2006 Performance Grant Awards. The 2006 Performance Grant Award was issued on April 1, 2006 and the payout amount was determined based on achievement of performance goals for the performance period ended December 31, 2007. Payouts can range from 0% to 200%. The actual payout was 138%. The payout amounts were as follows: Mr. Farrell $1,945,800; Mr. Chewning $538,200; Mr. McGettrick $438,840; Mr. Johnson $310,500; and Mr. Christian $215,280.*

(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 Dominion s qualified pension plan and nonqualified executive retirement plans. There are no above-market earnings on non-qualified deferred compensation plans. These accruals 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; (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 relevant factors.*

(5) ***All Other Compensation** amounts for 2007 are as follows:*

	Executive Perquisites (a) ($)	Life Insurance Premiums ($)	Tax Gross-up ($)	Employee Savings Plan Match (b) ($)	Company Match Above IRS Limits (c) ($)	Vacation Sold Back to Company ($)	Dividends Paid on Restricted Stock ($)	Total All Other Compensation ($)
Thomas F. Farrell	45,560	27,198	10,833	3,173	12,338	9,943	189,758	298,803
Thomas N. Chewning	7,221	34,410	1,002	2,611	6,506	4,815	79,678	136,243
Mark F. McGettrick	13,555	13,350	45	4,770	7,251	0	48,979	87,950
Jay L. Johnson	10,344	26,301	1,850	3,375	3,632	0	39,353	84,855
David A. Christian	16,130	10,164	263	4,320	5,117	0	28,824	64,818

(a) Unless noted, the amounts in this column for all officers are comprised of the following: personal use of a company vehicle; personal use of corporate aircraft (Mr. Farrell only); financial planning; health and wellness allowance and other benefits. For Mr. Farrell, personal use of the corporate aircraft was $33,218. 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 97% of the use of the corporate aircraft is for business purposes.

(b) Paid under the terms of Dominion s 401(k) Plan.

(c) Represents each payment of lost 401(k) Plan matching contribution due to IRS limits.

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GRANTS OF PLAN-BASED AWARDS[1] [2]

The following table provides information about stock awards and non-equity incentive awards granted to the named executive officers during the year ended December 31, 2007.

Name	Grant Approval Date[3]	Grant Date[3]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold ($)	Target ($)	Maximum ($)	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Options Award[3]
Thomas F. Farrell, II							
2007 Annual Incentive Plan[4]			$ 0	$ 620,400	$ 1,240,800		
2007 Performance Grant[5]			0	1,410,000	2,820,000		
2007 Restricted Stock Grant[5]	3/28/2007	4/3/2007				31,513	$ 1,410,029
Thomas N. Chewning							
2007 Annual Incentive Plan[4]			$ 0	$ 237,861	$ 475,722		
2007 Performance Grant[5]			0	390,000	780,000		
2007 Restricted Stock Grant[5]	3/28/2007	4/3/2007				8,717	$ 390,020
Mark F. McGettrick							
2007 Annual Incentive Plan[4]			$ 0	$ 285,485	$ 570,969		
2007 Performance Grant[5]			0	397,500	795,000		
2007 Restricted Stock Grant[5]	3/28/2007	4/3/2007				8,884	$ 397,508
Jay L. Johnson							
2007 Annual Incentive Plan[4]			$ 0	$ 198,518	$ 397,035		
2007 Performance Grant[5]			0	225,000	450,000		
2007 Restricted Stock Grant[5]	3/28/2007	4/3/2007				5,029	$ 225,023
David A. Christian							
2007 Annual Incentive Plan[4]			$ 0	$ 171,259	$ 342,518		
2007 Performance Grant[5]			0	156,000	312,000		
2007 Restricted Stock Grant[5]	3/28/2007	4/3/2007				3,487	$ 156,013

(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 reflect only the approximate portion related to their services for the Company in the year presented.

(2) Share and per share amounts included in this table and related footnotes reflect Dominion s two-for-one stock split distributed in November 2007.

(3) On March 28, 2007, the CGN Committee approved the 2007 long-term compensation awards for Dominion officers, which consisted of a restricted Dominion stock grant and a performance grant. The 2007 restricted stock award was granted on April 3, 2007. The fair market value for the April 3, 2007 restricted stock grant was determined by taking the average of the high and low prices of Dominion stock on April 2, 2007 and was calculated to be $44.745 per share.

(4) The amounts in these rows include potential payouts under the 2007 AIP. Actual payouts earned are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. Under Dominion s 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, 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 funded to a specific target. For the 2007 AIP, funding is based on the achievement of consolidated operating earnings goals with the maximum funding capped at 200%.

For Dominion officers that are among the top most highly compensated group for 2007, which includes all of Dominion s named executive officers, pay-out under the 2007 AIP is based on goal weightings assigned to all officers except that for the CEO and CFO goal-weighting is based solely on consolidated financial and Six Sigma goals, 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 2007 target percentages of base salary for our named executive officers are as follows: Mr. Farrell 120%; Messrs. Chewning and McGettrick 95%; Mr. Johnson 85%; and Mr. Christian 70%.

(5) *On March 28, 2007, the CGN Committee approved a long-term compensation award for officers, which consists of two components of equal value: a restricted Dominion 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 2009 and can range from 0 to 200% of the target award. The amount earned by officers will depend on the level of achievement of two equally weighted metrics: 1) Dominion s total shareholder return (TSR) for the two-year period ended December 31, 2008 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, 2008. The payout percentages for TSR performance and targets and corresponding payout percentages for ROIC are shown in the 2007 Performance Grants section of the CD&A.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END[(1)(2)]

The following table summarizes the equity awards that have been made to our named executive officers that were outstanding as of December 31, 2007.

	Option Awards			Stock Awards	
Name	Number of Securities Underlying Unexercised Options (#) Exercisable[(3)]	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested[(4)] ($)
Thomas F. Farrell, II	188,000	$ 29.98	1/1/2009	39,348[(5)]	$ 1,867,082
	188,000	$ 29.98	1/1/2010	21,087[(6)]	$ 1,000,579
				40,558[(7)]	$ 1,924,486
				31,513[(8)]	$ 1,495,271
Thomas N. Chewning	117,000	$ 29.98	1/1/2009	23,582[(5)]	$ 1,118,954
	117,000	$ 29.98	1/1/2010	10,599[(6)]	$ 502,942
				11,219[(7)]	$ 532,329
				8,717[(8)]	$ 413,598
Mark F. McGettrick				11,340[(5)]	$ 538,077
				5,096[(6)]	$ 241,828
				9,148[(7)]	$ 434,063
				8,884[(8)]	$ 421,539
Jay L. Johnson				10,698[(5)]	$ 507,620
				4,808[(6)]	$ 228,140
				6,473[(7)]	$ 307,144
				5,029[(8)]	$ 238,626
David A. Christian				7,144[(5)]	$ 338,998
				4,448[(7)]	$ 212,956
				3,487[(8)]	$ 165,445
				3,148[(9)]	$ 149,365
				2,323[(10)]	$ 110,236

(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 reflect only the approximate portion related to their service for the Company.
(2) All option, share, option exercise price and per share amounts included in this table and related footnotes reflect the Dominion s two-for-one stock split distributed in November 2007.
(3) All options presented in this table are fully vested and exercisable. There are no unexercisable options outstanding.
(4) Based on closing stock price of $47.45 on December 31, 2007, which was the last day of Dominion s fiscal year on which its common stock was traded.
(5) Shares vest on February 24, 2008.
(6) Shares vest on May 11, 2009.
(7) Shares vest on April 1, 2009.
(8) Shares vest on April 3, 2010.
(9) Shares vest on February 18, 2009.
(10) Shares vest on December 20, 2009.

OPTION EXERCISES AND STOCK VESTED [(1)(2)]

The following table provides information about the value realized by the named executive officers on option award exercises and stock awards vesting during the year ended December 31, 2007.

Name	Option Awards[3] Number of Shares Acquired on Exercise (#)	Option Awards[3] Value Realized on Exercise ($)	Stock Awards Number of Shares Acquired on Vesting (#)	Stock Awards Value Realized on Vesting ($)
Thomas F. Farrell, II	188,000	$ 2,603,227	21,087	$ 946,238
Thomas N. Chewning	78,000	1,129,422	10,599	475,593
Mark F. McGettrick	70,667	1,133,710	5,096	228,694
Jay L. Johnson	100,000	1,344,962	4,808	215,749
David A. Christian	0	0	3,147	136,238

(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 reflect only the approximate portion related to their service for the Company.
(2) Share amounts included in this table reflect Dominion s two-for-one stock split distributed in November 2007.
(3) All stock options were exercised pursuant to Rule 10b5-1 trading plans.

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PENSION BENEFITS [1][2]

The following table shows the present value of accumulated benefits payable to the named executive officers under the plans listed in the table. No payments were made to any of the named executive officers during Fiscal Year 2007 under any of the plans listed in this table.

Name	Plan Name	Number of Years Credited Service[3]	Present Value of Accumulated Benefit
Thomas F. Farrell, II	Pension Plan	12.00	$ 104,993
	Benefit Restoration Plan (Pre-2005)	9.00	194,553
	Supplemental Retirement Plan (Pre-2005)	9.00	2,004,195
	New Benefit Restoration Plan (Post-2004)	21.43	1,171,222
	New Supplemental Retirement Plan (Post-2004)	21.43	2,745,915
Thomas N. Chewning	Pension Plan	20.00	261,498
	Benefit Restoration Plan (Pre-2005)	25.00	1,197,333
	Supplemental Retirement Plan (Pre-2005)	25.00	1,550,289
	New Benefit Restoration Plan (Post-2004)	30.00	274,505
	New Supplemental Retirement Plan (Post-2004)	30.00	370,927
Mark F. McGettrick	Pension Plan	23.50	189,319
	Benefit Restoration Plan (Pre-2005)	20.50	127,149
	Supplemental Retirement Plan (Pre-2005)	20.50	187,703
	New Benefit Restoration Plan (Post-2004)	28.42	1,074,738
	New Supplemental Retirement Plan (Post-2004)	28.42	929,292
Jay L. Johnson	Pension Plan	7.33	117,766
	Benefit Restoration Plan (Pre-2005)	4.33	63,111
	Supplemental Retirement Plan (Pre-2005)	4.33	585,006
	New Benefit Restoration Plan (Post-2004)	14.10	389,871
	New Supplemental Retirement Plan (Post-2004)	14.10	740,145
David A. Christian	Pension Plan	23.50	217,748
	Benefit Restoration Plan (Pre-2005)	20.50	132,840
	Supplemental Retirement Plan (Pre-2005)	20.50	248,377
	New Benefit Restoration Plan (Post-2004)	23.50	259,441
	New Supplemental Retirement Plan (Post-2004)	23.50	667,164

(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 reflect only the approximate portion related to their service for the Company.

(2) The years of credited service and the present value of accumulated benefits were determined by Dominion s plan actuaries, using the appropriate accrued service and pay and other assumptions similar to those used for accounting and disclosure purposes.

(3) Years of credited service for the Pension Plan are actual years accrued by the executive from his date of participation to December 31, 2007. Year of credited service for the Pre-2005 Plans is accrued service from the date of participation up to December 31, 2004. Service for the Benefit Restoration Plan Post 2004 and the Supplemental Retirement Plan Post 2004 is the executives potential total service, including extra years of credited service granted to the executive by the CGN Committee for purposes of calculating benefits under these plans, times a fraction equal to service from the date of participation until the age when maximum credited service would be earned. Please refer to the Employee and Executive Benefits section of the CD&A for information about the requirements for receiving extra years of credited service for each named executive officer.

Dominion Pension Plan

The Dominion Pension Plan is a tax-qualified defined benefit pension plan. All executives are participants in the Pension Plan.

The Pension Plan provides unreduced retirement benefits at termination of employment at or after age 65 or, with three years of service, at age 60. Reduced retirement is available after age 55 with three years of service. For retirement between ages 55 and 60, the benefit is reduced 0.25% per month for each month after age 58 and before age 60 and 0.50% per month for each month between ages 55 and 58. All named executive officers have more than three years of service.

The Pension Plan basic benefit is calculated using a formula based on (1) age at retirement; (2) final average earnings; (3) estimated Social Security benefits; and (4) credited service. Final average earnings are the average of the participant s 60 highest consecutive months of base pay during the last 120 months worked. Earnings are limited to the IRS maximum which was $225,000 for 2007. Bonuses are not included in base pay. Credited service is measured in months, up to a maximum of 30 years of credited service. The estimated Social Security benefit taken

into account is the assumed Social Security benefit payable starting at age 65 or actual retirement date, if later, assuming that the participant has no further employment after leaving Dominion.

These factors are then applied in a formula. The formula has different percentages for credited service before 2001 and after 2000. The benefit is the sum of the amounts from these two formulas.

For Credited Service before 2001:

2.03% **times** Final Average Earnings **times** Credited Service before 2001	**Minus**	2.00% **times** estimated Social Security benefit **times** Credited Service before 2001

For Credited Service after 2000:

1.80% **times** Final Average Earnings **times** Credited Service after 2000	**Minus**	1.50% **times** estimated Social Security benefit **times** Credited Service after 2000

Credited Service is limited to a total of 30 years for all parts of the formula and Credited Service after 2000 is limited to 30 years minus Credited Service before 2001.

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A vested participant who terminates employment before age 55 can start receiving benefit payments at any time after attaining age 55. If payments commence before age 65, the following reduction factors for the portion of the benefits earned after 2000 apply: age 64 9%; age 63 16%; age 62 23%; age 61 30%; age 60 35%; age 59 40%; age 58 44%; age 57 48%; age 56 52%; and age 55 55%.

Benefit payment options are a (1) single life annuity; (2) 50% joint and survivor annuity; (3) 100% joint and survivor annuity; and (4) Social Security leveling option with any of the other three benefit forms. The normal form of benefit is the single life annuity. All of the options are the actuarial equivalent of the single life annuity. The Social Security leveling option pays a larger benefit equal to the estimated Social Security benefits until the participant is age 62 and then reduced payments after age 62.

The Pension Plan also includes a Special Retirement Account (SRA), which is in addition to the pension benefit. The SRA is credited with 2% of base pay each month beginning in 2001 as well as interest based on the 30-year Treasury bond rate. The SRA can be paid in a lump sum or paid as part of an annuity with the other benefits under the Pension Plan.

Dominion Benefit Restoration Plans

Dominion sponsors the New Benefit Restoration Plan, effective as of January 1, 2005 (New BRP), and the Frozen Benefit Restoration Plan, frozen as of December 31, 2004 (Frozen BRP), which are discussed in the CD&A under *Employee and Executive Benefits*. Neither plan is tax-qualified.

The Frozen BRP provides benefits accrued before 2005 that are intended to be exempt from Section 409A of the Internal Revenue Code. The New BRP was adopted to accommodate the enactment of and is intended to comply with Section 409A of the Internal Revenue Code for benefits accrued after 2004. The overall restoration benefit was not changed by adoption of the New BRP.

The restoration benefit offers an additional incentive to attract and retain talented executives for Dominion by compensating them for the reduction in their benefits under Dominion s Pension Plan resulting from the application of limitations on compensation and benefits imposed on tax-qualified pension plans by the Internal Revenue Code.

A Dominion employee is eligible to participate in the New BRP if he or she is a member of management or a highly compensated employee and has had his or her benefit under the Dominion Pension Plan reduced or limited by the Internal Revenue Code. Dominion designates an employee to participate in the New BRP. The Frozen BRP has been closed to new participants since December 31, 2004. A participant remains a participant in either plan until he or she ceases to be eligible for any reason other than retirement or until his or her status as a participant is revoked by Dominion.

Upon retirement, the New BRP provides a monthly restoration benefit equal to the monthly benefit the participant would have received under Dominion s Pension Plan but for the limitations imposed by the Internal Revenue Code, reduced by the monthly benefit the participant actually receives under Dominion s Pension Plan, reduced further by the monthly benefit the participant receives under the Frozen BRP. Upon retirement, the

Frozen BRP provides a monthly restoration benefit equal to the monthly benefit the participant would have received under Dominion s Pension Plan but for the limitations imposed by the Internal Revenue Code, reduced by the monthly benefit the participant actually receives under Dominion s Pension Plan, in each case determined as though the participant had separated from service with Dominion no later than December 31, 2004.

As discussed above, the Internal Revenue Code limits the amount of compensation that may be taken into account under a qualified retirement plan to no more than a certain amount each year. For 2007, the limit was $225,000. The Internal Revenue Code also limits the total annual benefit that may be provided to a participant under a qualified defined benefit plan. For 2007, this limitation was the lesser of (i) $180,000 or (ii) the average of the participant s compensation during the three consecutive years in which the participant had the highest aggregate compensation.

In each plan, retirement means the participant s termination of employment with Dominion at a time when the participant is entitled to receive benefits under Dominion s Pension Plan. A participant who terminates employment prior to retirement is generally not entitled to a restoration benefit. However, a participant who becomes totally and permanently disabled prior to retirement or who dies prior to reaching retirement eligibility is entitled to the restoration benefit.

A participant s accrued restoration benefit is calculated based on the default annuity form under Dominion s Pension Plan. Under the New BRP, the restoration benefit is generally paid in the form of a single cash lump sum, unless the participant elects to receive a single life or 50% or 100% joint and survivor annuity. Under the Frozen BRP, the restoration benefit is usually paid in the form of a single cash lump sum, unless the participant elects to receive a single life or 50% or 100% joint and survivor annuity.

For purposes of these plans and the supplemental retirement plans described below, the present value of the accumulated benefit is calculated using actuarial and other factors as determined by the plan actuaries and approved by Dominion s Administrative Benefit Committee. Actuarial assumptions used for December 31, 2007 calculations include: discount rate of 6.60%; Frozen BRP and Frozen ESRP lump sum rate of 3.87%; New BRP and New ESRP lump sum rate of 5.85%; BRP cost of living adjustment of 1.625%; and the 1994 Group Annuity Mortality tables for post-retirement only.

Dominion Executive Supplemental Retirement Plans

Dominion sponsors the New Executive Supplemental Retirement Plan, effective as of January 1, 2005 (New ESRP), and the Frozen Executive Supplemental Retirement Plan, frozen as of December 31, 2004 (Frozen ESRP), which are discussed in the *Employee and Executive Benefits* section of the CD&A. Neither plan is tax-qualified.

The Frozen ESRP provides benefits accrued before 2005 that are intended to be exempt from Section 409A of the Internal Revenue Code. The New ESRP was adopted specifically to accommodate the enactment of and is intended to comply with Section 409A of the Internal Revenue Code for benefits accrued after 2004. The overall supplemental retirement benefit was not changed by adoption of the New ESRP.

The supplemental retirement benefit offers an additional incentive to attract and retain talented executives for Dominion. In light of the competitive industry in which it does business, Dominion feels that the normal pension plan benefit (even as increased by the Benefit Restoration Plan benefit) is insufficient to fulfill this purpose on its own.

Any elected officer of Dominion is eligible to participate in the New ESRP. Dominion designates an officer to participate. The Frozen ESRP has been closed to new participants since December 31, 2004. A participant remains a participant in either plan until he or she ceases to be an elected officer or until participation is revoked by Dominion.

The New ESRP provides for an annual retirement benefit equal to 25% of a participant s final cash compensation, based on his or her compensation and subject to age and years of service as of retirement, reduced by the annual retirement benefit provided under the Frozen ESRP. The Frozen ESRP provides for an annual retirement benefit equal to 25% of a participant s final cash compensation, based on his or her compensation and subject to age and years of service as of December 31, 2004. The retirement benefit is only payable for ten years unless Dominion designates the participant to receive lifetime benefits as described below.

A participant s final cash compensation includes, as of the relevant determination date, the participant s annual rate of base salary then in effect plus the target amount payable under Dominion s annual incentive plan for the year in which the determination is made. Final cash compensation does not include the value of equity awards, gains from the exercise of stock options, long-term cash incentive awards, perquisites or any other form of compensation.

A participant in either plan is entitled to the full retirement benefit if he or she separates from service with Dominion after reaching age 55 and achieving 60 months of service. Months of service generally include any months of service with Dominion, except that, for new participants who join the New ESRP on or after December 1, 2006, months of service only include months of service with Dominion while a participant in the New ESRP. Current named executive officers who are entitled to a full ESRP retirement benefit are: Messrs. Chewning and Johnson.

A participant who separates from service with Dominion with at least 60 months of service but who has not yet reached age 55 is entitled to a reduced retirement benefit, calculated by multiplying the full retirement benefit described above by a fraction, the numerator of which equals the participant s total number of months of service since becoming a participant, and the denominator of which equals the total number of months between the date the participant became a participant and age 55. Partial months are disregarded in this calculation. Messrs. Farrell, McGettrick and Christian are the only named executive officers who are not entitled to a full retirement benefit. See the discussion above regarding additional years of age and service.

A participant who separates from service with Dominion with less than 60 months of service is generally not entitled to a retirement benefit. However, a participant who becomes totally and permanently disabled prior to separation from service is entitled to a full retirement benefit, regardless of age or months of service. In addition, the beneficiary of a participant who dies prior to reaching retirement eligibility is entitled to the participant s full retirement benefit.

A participant s accrued retirement benefit is initially calculated as an annual amount payable in monthly installments for a period of 120 months. However, the New ESRP allows Dominion to designate certain participants as eligible for a retirement benefit for their lifetimes. Messrs. Farrell and Chewning will receive this benefit for their lifetime. Mr. McGettrick will receive this benefit for his lifetime if he is employed with Dominion at age 60. Mr. Johnson will receive this benefit for his lifetime after he has completed 10 years of actual service with Dominion. Mr. Christian will receive this benefit for his lifetime if he is employed with Dominion at age 60.

Under the New ESRP, the retirement benefit is generally paid in the form of a single cash lump sum unless a participant (other than a lifetime participant) elects monthly installment payments guaranteed for 120 months or a lifetime participant elects a single life annuity with 120 guaranteed monthly payments. Under the Frozen ESRP, the retirement benefit is usually paid in the form of a single cash lump sum unless the participant elects monthly installments guaranteed for 120 months, or unless a lifetime participant elects a single life annuity with 120 guaranteed monthly payments.

NONQUALIFIED DEFERRED COMPENSATION [1]

Name	Aggregate Earnings in Last FY (as of 12/31/07) ($)	Aggregate Balance at Last FYE (as of 12/31/2007) ($)
Thomas F. Farrell, II	4,017	61,163
Thomas N. Chewning	1,067	7,337
Mark F. McGettrick	58,351	502,421
Jay L. Johnson	37,040	318,302
David A. Christian	724	11,780

(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. Dominion does not currently offer any nonqualified deferred compensation plans to its officers or other employees. The Aggregate Balance at Last FYE column includes salary and bonus deferrals, lost company match and vested restricted stock which would have been reported in prior year s Summary Compensation Tables.*

The Nonqualified Deferred Compensation table reflects, in aggregate, the plan balances for two former plans offered to Dominion officers and other highly compensated employees: The Dominion Resources, Inc. Executives Deferred Compensation Plan, which was amended and restated as of December 31, 2004 to freeze the plan as of that date (Frozen Deferred Compensation Plan); and The Dominion Resources, Inc. Security Option Plan, which was amended and restated effective December 31, 2004 to freeze the plan as of that date (Frozen DSOP). While the Frozen DSOP was not a deferred compensation plan, but an option plan, we are including information regarding the plan and any balances under the plan in this table to make full disclosure about possible future payments to officers under the employee benefit plans.

The Frozen Deferred Compensation Plan includes amounts previously deferred from one of the following categories of compensation: (i) salary; (ii) bonus; (iii) vesting restricted stock; and (iv) gains from stock option exercises. The plan also provided for company contributions of lost company 401(k) Plan match contributions and transfers from several CNG deferred compensation plans. The Frozen Deferred Compensation Plan provides for 28 investment funds for the plan balances, including a Dominion Stock Fund. Participants may change investment elections on any business day. Any vested restricted stock and gain from stock option exercises that were deferred are kept in the Dominion Stock Fund. Earnings are calculated based on the performance of the underlying investment fund. No preferential earnings are paid, and therefore no earnings from these plans are included in the Summary Compensation Table.

The named executive officers invested in the following funds with rates of returns for 2007 as noted below. Except for the Dominion Fixed Income Fund, all of the funds have the same rate of returns as corresponding publicly available mutual funds.

Vanguard 500 Index Fund	5.4%
Dominion Resources Stock Fund	16.98%
Dominion Fixed Income Fund	4.85%

The Dominion Fixed Income Fund is an option that provides a fixed return rate set prior to the beginning of the year. The investment management department of Dominion determines the rate based on its estimate of the rate of return on Dominion assets in the trust for the Frozen Deferred Compensation Plan.

Under the terms of the Frozen Deferred Compensation Plan, participants have the ability to change their distribution schedule for benefits under the plan with six months notice to the plan administrator. Participants may elect the following Benefit Commencement Dates:

- In February after the calendar year in which they terminate employment due to retirement;
- In February after the calendar year in which they terminate employment due to retirement, but not before February of a specific calendar year; or
- In February of a specific calendar year.

The default Benefit Commencement Date is February 1 after the year in which the participant retires. Participants may elect multiple Benefit Commencement Dates; however, all new elections must be made at least six months before an existing Benefit Commencement Date. Withdrawals less than six months prior to an existing Benefit Commencement Date are subject to a 10% early withdrawal penalty. Account balances must be fully paid out no later than February 28, ten calendar years after a participant retires or becomes disabled. If a participant retires from the company, he or she may continue to defer an account balance provided that the total balance is distributed by this deadline. In the event of termination of employment, for reasons other than death, disability or retirement, before an elected Benefit Commencement Date, benefit payments will be distributed in a lump sum as soon as administratively practicable. Hardship distributions, prior to an elected Benefit Commencement Date, are available under certain limited circumstances.

Participants may elect to have their benefit paid in a lump sum payment or equal annual installments over a period of whole years from one to ten years. Once they begin receiving annual

installment payments, they can make a one-time election to either 1) receive their remaining account balance in the form of a lump sum distribution or 2) change their remaining installment payment period. Any election must be approved by Dominion before it is effective. All distributions are made in cash with the exception of the Deferred Restricted Stock Account and the Deferred Stock Option Account, which are distributed in the form of Dominion common stock.

The Frozen DSOP enabled employees to defer all or a portion of their salary and bonus and receive options on various mutual funds. Participants also received lost company matching contributions to the 401(k) Plan in the form of options under this plan. DSOP Options can be exercised at any time before their expiration date. On exercise, the participant receives the excess of the value, if any, of the underlying mutual funds over the strike price. The participant can currently choose among options on 26 mutual funds, and there is not a Dominion stock alternative or a fixed income fund. Participants may change options among the mutual funds on any business day. Benefits grow/decline based on the total return of the mutual funds selected. Any options that expire do not have any value. Options expire under the following terms:

- Options expire on the last day of the 120th month after retirement or disability;

- Options expire on the last day of the 24th month after the participant s death (while employed);
- Options expire on the last day of the 12th month after the participant s severance;
- Options expire on the 90th day after termination with cause; and
- Options expire on the last day of the 120th month after severance following a Change in Control.

The named executive officers as a group held options on the following publicly available mutual funds which had the rates of returns for 2007 as noted below.

Vanguard Short-Term Bond Index	7.2%
Vanguard Small Cap Growth Index	9.6%
Vanguard Small Cap index	1.2%
Vanguard Extended Market Index	4.3%
Vanguard U.S. Value	-0.7%
Artisan International Investor	19.7%
Harbor International Fund	21.8%
Janus Growth & Income Fund	8.7%
Janus Mid Cap Value Investor	7.4%

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Potential Payments Upon Termination or Change in Control

Under certain circumstances, Dominion provides benefits to eligible employees upon termination of employment, including a termination of employment involving a change in control of Dominion, that are in addition to termination benefits for employees in the same situation. This section describes and explains these benefits generally, and specifically the incremental benefits that pertain to our named executive officers.

Review of Executive Benefits

As described in the *Employee and Executive Benefits* section of the CD&A, a Dominion officer who terminates employment after he or she has attained age 55 is eligible to receive payment of benefits under the Benefit Restoration Plans (the Frozen BRP and the New BRP) and the Executive Supplemental Retirement Plans (the Frozen ESRP and the New ESRP). If an officer becomes disabled or dies before age 55, the officer or his beneficiary will be entitled to payment of benefits as if the officer had attained age 55, was fully vested in the benefits, and retired. An officer who voluntarily terminates employment before attaining age 55 and who is vested is entitled to a pro-rated benefit under the Frozen ESRP and New ESRP. Certain officers have been designated by the CGN Committee as life participants for purposes of calculating their benefits under the Frozen ESRP and New ESRP; this means the benefit is calculated as a benefit payable for life, instead of as a benefit payable for 120 months. Messrs. Farrell and Chewning are life participants. The actuarial present value of the Frozen BRP, New BRP, Frozen ESRP and New ESRP benefits (using unreduced normal retirement age assumptions) for the named executive officers is disclosed in the Pension Benefits table.

Restricted stock awards granted to Dominion officers before 2006 become fully vested when the officer retires with eligibility for benefits under the Dominion s Pension Plan. Restricted stock and performance-based awards granted in 2006 and 2007 will become vested on a pro-rated basis if the officer terminates employment before the vesting date due to death, disability, retirement, or an involuntary termination without cause. Upon a change in control at Dominion, the awards will become vested on a pro-rated basis at the time the change in control occurs and fully vested if the officer terminates employment following the change in control due to death, disability, retirement, or an involuntary termination without cause.

All employees (officers and other employees) who have both (i) completed 10 years of service and (ii) attained age 55 are eligible to participate in the company s retiree medical plan and retiree life insurance plan.

Change in Control

Dominion has entered into an Employment Continuity Agreement with each of its officers, including the named executive officers. While Dominion has determined these agreements are consistent with the practices of its peer companies, the most important reason for these agreements is to protect Dominion in the event of an anticipated or actual change in control at Dominion. (change in control is

defined in the *Other Agreements and Special Payments* section of the CD&A.) In a time of transition, it is critical to protect shareholder value by retaining and continuing to motivate the company s core management team. In a change of control situation, workloads typically increase dramatically, outside competitors are more likely to attempt to recruit top performers away from the company, and officers and other key employees may consider other opportunities when faced with uncertainties at their own company. Therefore, the Employment Continuity Agreements provide security and protection to officers in such circumstances for the long-term benefit of Dominion and its shareholders.

Each agreement has a three-year term and is automatically extended annually for an additional year, unless cancelled by Dominion.

Dominion s Employment Continuity Agreements require two triggers for the payments of the benefits disclosed in the table below:

- There must be a change in control at Dominion; and
- The executive must either be terminated without cause, or terminate his or her employment with the surviving company after a constructive termination. Constructive termination means the executive s salary, incentive compensation or job responsibility is reduced after a change in control, or the executive s work location is relocated more than 50 miles without his or her consent.

If an executive s employment following a change in control is terminated without cause or due to a constructive termination, the executive will become entitled to the following termination benefits:

Lump sum severance payment equal to three times base salary plus annual bonus (larger of target bonus or actual bonus paid in previous three years).

Full vesting of benefits under ESRP and BRP Plans with five years of additional credited age and five years of credited additional service from the Change in Control date.

Group-Term life insurance: If executive elects to convert group-term insurance to an individual policy, the company pays the premiums for 12 months.

Executive life insurance: Premium payments will continue to be paid by the company until the earlier of: (1) the fifth anniversary of the termination date, or (2) the later of the tenth anniversary of the policy or the date the executive attains age 64.

Retiree medical: retiree medical coverage will be determined under the relevant plan with additional age and service credited as provided under executive s employment agreement (if any) and including five additional years credited to age and five additional years credited to service.

Outplacement services for 1 year (or $25,000).

If any payments are classified as excess parachute payments for purposes of Internal Revenue Code Section 280G and the executive incurs the excise tax, the company will pay the executive an amount equal to the excise tax plus a gross-up multiple.

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The table below provides the payments that would be earned by each named executive officer if his employment was terminated, or constructively terminated, as of December 31, 2007 as a result of a change in control. For officers that are retirement eligible (Messrs. Chewning and Johnson), these benefits would be in addition to the retirement benefits disclosed in the Pension Benefits table. For executives who are not retirement eligible (Messrs. Farrell, McGettrick and Christian), these benefits are in addition to the benefits they would receive for a termination without cause discussed below in the *Additional Post Employment Benefits for Named Executive Officers* section. All stock options held by our named executive officers are vested. In the event of a change in control, outstanding options could be exercised or the CGN Committee may take actions with respect to unexercised options that it deems appropriate.

Additional Post Employment Benefits for Named Executive Officers

Under the terms of letter agreements with our named executive officers, the following benefits are available in addition to the benefits described above. These benefits are quantified in the table below, assuming the triggering event set forth in the table occurred on December 31, 2007.

Mr. Farrell: Pursuant to his letter agreement dated February 27, 2003, as amended effective as of January 1, 2006, if Mr. Farrell s employment is involuntarily terminated without cause before he attains age 55, Mr. Farrell will be entitled to participate in Dominion s retiree medical plan to the same extent as retired employees under the terms of the plan offered to retiring employees as of the termination date. In addition, any unvested restricted stock granted to Mr. Farrell before 2006 shall vest upon the involuntary termination date.

Mr. Farrell s benefits under the Frozen BRP, New BRP, Frozen ESRP, and new ESRP are disclosed in the Pension Benefits table. With the exception of benefits payable upon a termination due to death or disability or following a change in control, Mr. Farrell is not entitled to any enhanced benefits under these plans. The incremental benefits payable under these plans as of December 31, 2007 if Mr. Farrell had died or become disabled or terminated employment following a change in control are disclosed in the table below.

Mr. Chewning: Mr. Chewning has attained retirement age under Dominion s tax-qualified Pension Plan and is eligible for benefits under the Frozen BRP, New BRP, Frozen ESRP, and New ESRP. If Mr. Chewning had retired as of December 31, 2007, he would not have been entitled to any enhanced benefits under these plans.

Pursuant to the non-compete and non-solicitation provisions of his letter agreement dated February 28, 2003, Mr. Chewning will be entitled to a lump sum cash payment upon his retirement equal to one time his annual base salary in effect at his retirement date. The payment serves as consideration for Mr. Chewning s agreement to honor the non-compete and non-solicitation terms of the agreement for a two-year period following his retirement. Mr. Chewning has attained retirement age and, therefore, he would have been entitled to this payment if he had retired on December 31, 2007.

Mr. McGettrick: Pursuant to his letter agreement dated February 13, 2007, Mr. McGettrick is entitled to five additional years of credited age and five additional years of credited service for purposes of computing his benefits under the Frozen BRP, New BRP, Frozen ESRP, New ESRP, and Dominion s tax-qualified Pension Plan, as well as his eligibility for benefits under Dominion s retiree medical and retiree life insurance plans. Any additional Pension Plan benefit shall be paid from Dominion assets, and not from the trust established for the Pension Plan. Mr. McGettrick s benefit under the Frozen BRP, New BRP, Frozen ESRP, and New ESRP calculated with the additional credited years of age and service are disclosed in the Pension Benefits table. With the exception of benefits payable upon a termination following a change in control, Mr. McGettrick is not entitled to any enhanced benefits under these plans. The incremental benefits payable under these plans as of December 31, 2007 if Mr. McGettrick had terminated employment following a change in control are disclosed in the table below. If Mr. McGettrick terminates employment before he attains age 55, he will be deemed to have retired for purposes of determining vesting credit under the terms of his outstanding restricted stock and performance grant awards.

Mr. Johnson: Mr. Johnson has attained retirement age under Dominion s tax-qualified Pension Plan and is eligible for benefits under the Frozen BRP, New BRP, Frozen ESRP, and New ESRP. If Mr. Johnson had retired as of December 31, 2007, he would not have been entitled to any enhanced benefits under these plans.

Mr. Christian: If Mr. Christian had terminated as of December 31, 2007, he would not have been entitled to any enhanced benefits under these plans.

All cash payments disclosed in the table below are payable as a lump sum, unless noted otherwise. Certain lump-sum amounts will be paid six months after termination in order to be in compliance with Section 409A of the Internal Revenue Code.

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Incremental Payments Upon Termination and Change in Control (Assuming December 31, 2007 termination) (1)

	Non-Qualified Plan Payment	Restricted Stock (2)	Performance Grant	Non-Compete Payments (3)	Severance Payments	Retiree Medical & Executive Life Insurance (4)	Outplacement Services	Excise Tax & Tax Gross-Up	Total
Thomas F. Farrell, II.									
Termination Without Cause	$	$ 4,361,459	$ 601,129	$	$	$ 58,079	$	$	$ 5,020,667
Voluntary Termination									
Death / Disability	738,047	1,493,120	601,129						2,832,296
Change In Control (5)	2,814,970	1,925,958	808,871		3,412,200	27,198	11,750	3,779,700	12,780,647
Thomas N. Chewning									
Termination Without Cause		413,008	166,269	250,380		76,169			905,826
Voluntary Termination		413,008	166,269	250,380		76,169			905,826
Death / Disability		413,008	166,269						579,277
Change In Control (5)		532,919	223,731		1,464,723				2,221,373
Mark F. McGettrick									
Termination Without Cause		357,687	169,467			71,792			598,946
Voluntary Termination									
Death / Disability		357,687	169,467						527,154
Change In Control (5)	1,025,423	497,915	228,033		1,757,984	13,350	13,250	1,536,355	5,072,310
Jay L. Johnson									
Termination Without Cause		238,295	95,925						334,220
Voluntary Termination		238,295	95,925						334,220
Death / Disability		238,295	95,925						334,220
Change In Control (5)	282,931	307,475	129,075		1,296,203	76,016	12,500	917,536	3,021,736
David A. Christian									
Termination Without Cause		165,219	66,508						231,727
Voluntary Termination									
Death / Disability	131,023	203,037	66,508						400,568
Change In Control (5)	1,867,758	687,395	89,492		1,247,746	83,718	12,000	1,877,984	5,866,093

(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 reflect only that portion which is allocated to the Company.

(2) Grants made prior to 2006 are fully vested upon retirement. Grants made in 2006 and after vest pro-rata upon retirement, termination without cause, death, disability or upon a change in control.

(3) Pursuant to a letter agreement dated February 28, 2003, Mr. Chewning will be entitled to a special payment of one times salary in exchange for a two-year non-compete requirement.

(4) Amounts in this column represent the value of the benefit that the executives would receive for executive life insurance and retiree medical coverage. Executive life insurance for Messrs. Farrell, McGettrick and Johnson is only available upon a change in control. Mr Johnson s annual executive life insurance premium is $26,560 and Mr. Christian s is $10,294. The premiums for these three executives would be paid for five years. Messrs. Farrell and McGettrick are eligible

for retiree medical if terminated without cause. Mr. Johnson and Mr. Christian are only eligible for retiree medical benefit upon a change in control. Mr. Chewning is entitled to executive life insurance coverage and retiree medical benefit upon any termination since he is retirement eligible. His annual executive life premium is $34,609 and is payable until May 2010. Retiree health benefits have been quantified using assumptions used for financial accounting purposes.

(5) *The amounts indicated upon a change in control are the incremental amounts that each executive would receive over the amounts indicated for a Termination Without Cause.*

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COMPENSATION COMMITTEE REPORT

The Company is a wholly-owned subsidiary of Dominion. Our Board is comprised of Messrs. Farrell, Chewning and Rogers. As executive officers of the Company, Messrs. Farrell and Chewning are not independent. Mr. Rogers is not considered to be independent because he is an officer of Dominion. Because our Board is not independent, we do not believe it is appropriate to have a separate compensation committee at our level. 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 which has retained the consulting firm of Pearl Meyer &

Partners to advise them on compensation matters. Our Board approves all compensation paid to the Company s executive officers based on Dominion s CGN Committee recommendations. In preparation for the filing of this Annual Report on Form 10-K, we reviewed and discussed management s Compensation Discussion and Analysis and approved it for inclusion in this document.

Thomas F. Farrell, II

Thomas N. Chewning

Steven A. Rogers

February 26, 2008

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

The table below sets forth as of February 1, 2008, the number of shares of Dominion common stock owned by directors and the executive officers named on the Summary Compensation Table. All option and share amounts included in this table and related footnotes reflect Dominion s two-for-one stock split distributed in November 2007.

Name of Beneficial Owner	Shares	Restricted Shares	Exercisable Stock Options	Total
Thomas F. Farrell, II(1)	291,534	281,928	800,000	1,373,462
Thomas N. Chewning(2)	244,944	138,760	600,000	983,704
Steven A. Rogers	24,021	17,038		41,059
Jay L. Johnson	66,096	54,016		120,112
Mark F. McGettrick	57,576	65,034		122,610
David A. Christian	42,004	42,896		84,900
All directors and executive officers as a group (7 persons)(3)	736,732	616,362	1,400,000	2,753,094

(1) Mr. Farrell disclaims ownership for 798 shares.

(2) As of February 1, 2008, Mr. Chewning had pledged 193,920 shares as collateral for a Wachovia Bank loan to a nonprofit organization. As of February 22, 2008, the loan was paid off and Mr. Chewning no longer has shares that are pledged as collateral for a loan.

(3) All directors and executive officers as a group own less than one percent of the number of Dominion common shares outstanding as of February 1, 2008. No individual executive officer or director owns more than one percent of the shares outstanding.

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Item 13. Certain Relationships and Related Transactions

Related Party Transactions

In February 2007, our Board adopted the Related Party Guidelines also approved by Dominion s Board of Directors. These guidelines, as subsequently revised in February 2008, were adopted in order to recognize the process to be used in identifying potential conflicts of interest arising out of financial transactions, arrangements and relations between the Company and any related persons. Under our guidelines, a related person is a director, executive officer, director nominee, a beneficial owner of more than 5% of Dominion s common stock, or any immediate family member of one of the foregoing persons. A related party transaction is any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) or any series of similar transactions, arrangements or relationships in excess of $120,000 in which Dominion (and/or any of its consolidated subsidiaries) is a party and in which the related person has or will have a direct or indirect material interest.

In determining whether a direct or indirect interest is material, the significance of the information to investors in light of all circumstances is also considered. The importance of the interest to the person having the interest, the relationship of the parties tothe transaction with each other and the amount involved are among the factors considered in determining the significance of the information to the investors.

Our guidelines set forth certain transactions which are not considered to be related party transactions including, compensation and expense reimbursement paid to directors and executive officers in the ordinary course of performing their duties; transactions with other companies where the related party s only relationship is as an employee, director or owner of less than 10%, if the aggregate amount involved does not exceed the greater of $1 million or 2% of that company s gross revenues; and charitable contributions which are less than the greater of $1 million or 2% of the charity s annual receipts. The full text of the guidelines can be found on Dominion s website at www.dom.com/about/governance/index.jsp.

We collect information about potential related party transactions (those in which a related party may have a material interest) in our annual questionnaires completed by directors and executive officers. The Corporate Secretary and the General Counsel review the potential related party transactions and assess whether any of the identified transactions constitute a related party transaction. Any identified related party transactions are then reported to Dominion s Compensation, Governance and Nominating (CGN) Committee. Dominion s CGN Committee reviews and considers relevant facts and circumstances and determines whether to ratify, approve or deny the related party transactions identified. Dominion s CGN Committee may only approve or ratify related party transactions that are not inconsistent with the best interests of Dominion and its shareholders and are in compliance with our Code of Ethics.

Since January 1, 2007 there have been no related party transactions involving the Company that were required either to be reported under the SEC related party rules or approved under the Company s policies.

Director Independence

We are a wholly-owned subsidiary of Dominion. The Board has determined that Thomas F. Farrell, II and Thomas N. Chewning, as executive officers of the Company and Steven A. Rogers, as an executive officer of Dominion, are not independent.

Item 14. Principal Accountant Fees and Services

The following table presents fees paid to Deloitte & Touche LLP for the fiscal years ended December 31, 2007 and 2006.

Type of Fees (millions)	**2007**	2006

Audit fees	**$ 1.85**	$ 0.77
Audit-related		0.04
Tax fees		
All other fees		
	$ 1.85	$ 0.81

Audit Fees. These amounts represent fees of Deloitte & Touche for the audit of our annual consolidated financial statements, the review of financial statements included in our quarterly Form 10-Q reports, and the services that an independent auditor would customarily provide in connection with subsidiary audits, statutory requirements, regulatory filings, and similar engagements for the fiscal year, such as comfort letters, attest services, consents, and assistance with review of documents filed with the SEC.

Audit-Related Fees. Audit-Related Fees consist of assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, audits of our employee benefit plans, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of generally accepted accounting principles to proposed transactions.

Our Board has adopted a pre-approval policy for our independent auditor s services and fees and has delegated to Dominion s Audit Committee the authority to pre-approve independent auditor services in accordance with the policy. In December 2007, Dominion s Audit Committee approved the independent auditor s services and fees for 2008.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

1. Financial Statements

See Index on page 28.

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

2. Exhibits

3.1	Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-2255, incorporated by reference).
3.2	Bylaws, as amended, as in effect on April 28, 2000 (Exhibit 3, Form 10-Q for the period ended March 31, 2000, File No. 1-2255, incorporated by reference).
4	Virginia Electric and Power Company agrees to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of its total consolidated assets.
4.1	See Exhibit 3.1 above.
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture, (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, File No. 1-2255, incorporated by reference).
4.3	Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank and Chemical Bank)), as Trustee (Exhibit 4(a), Form S-3 Registration Statement File No. 333-20561 as filed on January 28, 1997, incorporated by reference), Form of Second Supplemental Indenture (Exhibit 4.6, Form 8-K filed August 20, 2002, No. 1-2255, incorporated by reference).
4.4	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K, dated June 3, 1999, File No.1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K, dated October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); and Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K, dated March 22, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K, dated January 24, 2002, incorporated by reference); Seventh Supplemental Indenture dated September 1, 2002 (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K

filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference); Form of Sixteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Seventeenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference).

4.5	Virginia Electric and Power Company agrees to furnish to the Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of Dominion Resources, Inc. s total consolidated assets.
10.1	Services Agreement between Dominion Resources Services, Inc. and Virginia Electric and Power Company dated January 1, 2000 (Exhibit 10.19, Form 10-K for the fiscal year ended December 31, 1999, File No. 1-2255, incorporated by reference).
10.2	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255, incorporated by reference).

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10.3	$3.0 billion, Five-Year Credit Agreement dated February 28, 2006 among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A., as Syndication Agent and Barclays Bank PLC, Bank of Nova Scotia and Wachovia Bank, National Association, as Co-Documentation Agents and other lenders named therein (Exhibit 10.1, Form 8-K filed March 3, 2006, File No. 1-2255, incorporated by reference).
10.4*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.5*	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997, as amended and restated effective July 20, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference), as amended June 20, 2007 (filed herewith).
10.6*	Dominion Resources, Inc. 2005 Incentive Compensation Plan (Exhibit 10, Form 8-K filed March 3, 2005, File No. 1-8489, incorporated by reference), as amended April 27, 2007 (filed herewith).
10.7*	Form of Restricted Stock Grant under 2006 Long-Term Compensation Program approved March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.8*	Form of Performance Grant under 2006 Long-Term Compensation Program approved March 31, 2006, as amended and restated January 24, 2008 (Exhibit 10.1, Form 8-K filed January 30, 2008, File No. 1-8489, incorporated by reference).
10.9*	Form of Restricted Stock Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.1, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.10*	Form of Performance Grant under 2007 Long-Term Compensation Program approved March 30, 2007 (Exhibit 10.2, Form 8-K filed April 5, 2007, File No. 1-8489, incorporated by reference).
10.11*	Form of Employment Continuity Agreement for certain officers of the Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003, File No. 1-2255, incorporated by reference), as amended March 31, 2006 (Form 8-K filed April 4, 2006, File No. 1-8489, incorporated by reference).
10.12*	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (Exhibit 10(iii), Form 10-Q for the quarter ended June 30, 1997, File No. 1-8489, incorporated by reference).
10.13*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.14*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
10.15*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, effective January 1, 2005 (Exhibit 10.8, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 19, 2006 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2005, File No. 1-8489, incorporated by reference), amended December 1, 2006 (filed herewith), and further amended January 1, 2007 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference).
10.16*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, effective January 1, 2005 (Exhibit 10.9, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference), amended January 1, 2007 (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2006, File No. 1-8489, incorporated by reference).
10.17*	Dominion Resources, Inc. Leadership Stock Option Plan, effective July 1, 2000, as amended and restated effective July 20, 2001 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2001, File No. 1-2255, incorporated by reference).
10.18*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489, incorporated by reference).
12.1	Ratio of earnings to fixed charges (filed herewith).
12.2	Ratio of earnings to fixed charges and dividends (filed herewith).
21	Subsidiaries of the Registrant (filed herewith).

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

* *Indicates management contract or compensatory plan or arrangement.*

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

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ THOMAS F. FARRELL, II
(Thomas F. Farrell, II,
Chairman of the Board of Directors
and Chief Executive Officer)

Date: February 28, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 28th day of February, 2008.

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