VIRGINIA ELECTRIC & POWER CO
Form 10-K
February 26, 2009
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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, 2008

OR

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

Commission File Number 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

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

(804) 819-2000

(Registrant s telephone number)

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

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

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

None

Indicate by check mark 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 (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE.

None

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Virginia Electric and Power Company

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Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
affiliates	Other Dominion subsidiaries
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income (loss)
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DOE	Department of Energy
Dominion	Dominion Resources, Inc.
DRS	Dominion Resources Services, Inc., a subsidiary of Dominion
DVP	Dominion Virginia Power operating segment
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
Fitch	Fitch Ratings Ltd.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
kWh	Kilowatt-hour
Lehman	Lehman Brothers Holdings, Inc.
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
Moody s	Moody s Investors Service
Mw	Megawatt
mwhrs	Megawatt hours
NERC	North American Electric Reliability Corporation
North Anna	North Anna power station
North Carolina Commission	North Carolina Utilities Commission
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Pennsylvania Commission	Pennsylvania Public Utility Commission
PJM	PJM Interconnection, LLC
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Standard & Poor s	Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.
Surry	Surry power station
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission
West Virginia Commission	Public Service Commission of West Virginia

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Part I

Item 1. Business

The Company

Virginia Electric and Power Company (Virginia Power) is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. As of December 31, 2008, we served approximately 2.4 million retail customer accounts, including governmental agencies, as well as wholesale customers such as rural electric cooperatives and municipalities. 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 throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power and its consolidated subsidiaries. All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion).

As of December 31, 2008, we had approximately 7,500 full-time employees. Approximately 3,400 employees are subject to collective bargaining agreements.

We were incorporated in 1909 as a Virginia public service corporation. Our principal executive offices are located at 120 Tredegar Street, Richmond, Virginia 23219 and our telephone number is (804) 819-2000.

Operating Segments

We manage our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. We also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments. 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 23 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 2 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.

Revenue provided by our electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Changes in revenue are driven primarily by weather, customer growth and other factors impacting consumption such as the economy and energy conservation.

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. Variability in earnings results from changes in rates, the demand for services, and operating and maintenance expenditures.

As discussed in *Status of Electric Regulation in Virginia* under *Regulation*, the Virginia General Assembly enacted legislation in April 2007 that institutes a modified cost-of-service rate model for the Virginia jurisdiction of our utility operations, subject to base rate caps in effect through December 31, 2008. We currently anticipate that the 2009 base rate review will result in an increase in rates, however we cannot predict the outcome of future rate actions at this time.

Revenue provided by our electric transmission operations is based primarily on rates approved by 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 in earnings results from changes in rates and the timing of property additions, retirements and depreciation.

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved a return on equity (ROE) of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure.

In addition, in August 2008, FERC granted an application by our electric transmission operations requesting a revision to our cost of service to reflect an additional ROE incentive adder for eleven electric transmission enhancement projects and approved an incentive of 1.5% for four of the projects and an incentive of 1.25% for the other seven. See *Federal Regulations* in *Regulation* for additional information.

We are a member of 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).

Operationally, DVP continues to enhance the customer experience through solid reliability performance and by providing our customers the ability to manage their accounts on-line. At the end of 2008, over 600,000 of DVP s customers were signed up to manage their account on-line through dom.com and over 2 million transactions were performed. This reflects a transaction increase of 28% over 2007. Customers typically use the Internet

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for routine billing and payment transactions; however, we expect the addition of new 2008 options like connecting and disconnecting service and reporting outages and obtaining outage updates to continue to increase on-line usage.

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 growth in new customers.

Regulation

DVP s electric retail service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia Commission and the North Carolina Commission. 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.

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 our 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 authorized construction of numerous electric transmission upgrades through 2011. We are involved in two of the major construction projects, which are designed to improve the reliability of service to our customers and the region, and are subject to applicable state and federal permits and approvals.

The first project is an approximately 270-mile 500-kV transmission line that begins in southwestern Pennsylvania, crosses West Virginia, and terminates in northern Virginia, of which we will construct approximately 65 miles in Virginia (Meadow Brook-to-Loudoun line) and a subsidiary of Allegheny Energy, Inc. (Trans-Allegheny Interstate Line Company) will construct the remainder. In October 2008, the Virginia Commission authorized construction of the Meadow Brook-to-Loudoun line and affirmed the 65-mile route we proposed for the line which is adjacent to, or within, existing transmission line right-of-ways. The Virginia Commission s approval of the Meadow Brook-to-Loudoun line was conditioned on the respective state commission approvals of both the West Virginia and Pennsylvania portions of the transmission line. The West Virginia Commission s approval of Trans-Allegheny Interstate Line Company s application became effective in February 2009 and the Pennsylvania Commission granted approval in December 2008. In February 2009, Petitions for Appeal of the Virginia

Commission s approval of the Meadow Brook-to-Loudoun line were filed with the Supreme Court of Virginia by the Piedmont Environmental Council and others. The Meadow Brook-to-Loudoun line is expected to cost approximately $255 million and, subject to the receipt of all regulatory approvals, is expected to be completed in June 2011.

The second project is an approximately 60-mile 500-kV transmission line that we will construct in southeastern Virginia (Carson-to-Suffolk line). In October 2008, the Virginia Commission authorized the construction of the Carson-to-Suffolk line. This project is estimated to cost $224 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 are subject to applicable state and federal permits and approvals.

In addition, DVP s electric distribution network includes approximately 56,000 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of our electric lines contain right-of-ways that have been obtained from the apparent owner of real estate, but underlying titles have not been examined. Where right-of-ways 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* for additional information.

Seasonality

DVP s earnings vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. In addition, an increase in heating degree days does not produce the same increase in revenue as an increase in cooling degree days due to seasonal pricing differentials and because alternative heating sources are more readily available.

Generation

Generation includes our portfolio of electric generation facilities, power purchase agreements and our energy supply operations. Our electric generation operations primarily serve the supply requirements for our DVP segment s customers. Our generation mix is diversified and includes coal, nuclear, gas, oil, and renewables. 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 operations. As discussed in *Properties*, we have plans to add additional generation capacity to satisfy future growth in our utility service area.

Our earnings primarily result from the sale of electricity we generate. Due to 1999 Virginia deregulation legislation, as amended in 2004 and 2007, revenues for serving Virginia jurisdictional retail load were 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,

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annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, were reinstituted 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 base rate caps in effect through December 31, 2008. As a result, we reapplied the provisions of SFAS No. 71 to those operations on April 4, 2007, the date the legislation was enacted. We currently anticipate that the 2009 base rate review will result in an increase in rates, however we cannot predict the outcome of future rate actions at this time. Variability in earnings for our utility operations results from changes in rates, the demand for services, which is primarily weather dependent, and labor and benefit costs, as well as the timing, duration and costs of scheduled and unscheduled outages.

Competition

Retail choice was made available to our Virginia jurisdictional electric customers beginning January 1, 2003; however, no significant competition developed in Virginia. 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

Operations are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), the Department of Energy (DOE), the Army Corps of Engineers, the Virginia Commission, the North Carolina Commission and other federal, state and local authorities. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Properties

For a listing of 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 June 2008, we commenced the operation of two additional natural gas-fired electric generating units (Units 3 and 4) totaling 321 Mw at our Ladysmith power station (Ladysmith) to supply electricity during periods of peak demand. Construction has commenced on a fifth combustion turbine (Unit 5) which is expected to begin operations in mid-2009.

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. The Virginia Commission issued a final order in March 2008 (Final Order), approving a certificate to construct and operate the proposed Virginia City

Hybrid Energy Center, granting approval for us to continue to accrue AFUDC until capped rates end and approving a rate adjustment clause, allowing us current recovery of financing costs beginning January 1, 2009, as specified in the Final Order. In its Final Order, the Virginia Commission approved an initial return on common equity for the facility of 12.12%, consisting of a base return of 11.12% plus a 100 basis point premium that Virginia law provides for new conventional coal generation facilities. The Virginia Commission also authorized us to apply for an additional 100 basis point premium upon a demonstration that the plant is carbon-capture compatible. The enhanced return will apply to the Virginia City Hybrid Energy Center during construction and through the first twelve years of the facility s service life. In July 2008, the Southern Environmental Law Center (SELC), on behalf of four environmental groups, filed a Petition for Appeal of the Final Order with the Supreme Court of Virginia. A decision is expected in April 2009.

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 and an application for another air permit for hazardous emissions was filed in February 2008. In June 2008, the Virginia Air Pollution Control Board (the Air Board), which assumed consideration of the applications, approved and issued both permits. The Air Board approved lower emissions limits than had been requested, including limits for sulfur dioxide (SO_2) and mercury. The Air Board also adopted our proposal to convert our Bremo power station from coal to natural gas within two years of the Virginia City Hybrid Energy Center going into service. The Bremo conversion project is part of our overall effort to reduce air emissions and is contingent upon the Virginia City Hybrid Energy Center entering service and Bremo receiving all necessary approvals, including approval from the Virginia Commission. See *Environmental Strategy* for more information. Construction of the Virginia City Hybrid Energy Center has commenced and the facility is expected to be in operation by 2012 at an estimated cost of approximately $1.8 billion, excluding financing costs. In August 2008, the SELC, on behalf of four environmental groups, filed Petitions for Appeal in Richmond Circuit Court challenging the approval of both of the air permits.

We are considering the construction of a third nuclear unit at a site located at 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) to our affiliate, Dominion Nuclear North Anna, LLC (DNNA). Also in November 2007, we along with ODEC, filed an application with the NRC for a Combined Construction Permit and Operating License (COL) that references a specific reactor design and 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. In December 2008, we terminated a long-lead agreement with our vendor with respect to the reactor design identified in our COL application and certain related equipment. We intend to conduct a competitive process in 2009 to determine if vendors can provide an advanced technology reactor that could be licensed and built under terms acceptable to us. If, as a result of this process, we choose a different reactor design, we will amend our COL application, as necessary. We have not yet committed to building a new nuclear unit.

The NRC is required to conduct a hearing in all COL proceedings. In August 2008, the Atomic Safety and Licensing Board of the NRC granted a request for a hearing on one of eight contentions filed by the Blue Ridge Environmental Defense League. The mandatory NRC hearing will be uncontested with respect to other issues. Dominion has a cooperative agreement with the DOE to share equally the cost of developing the COL. In April 2008, Dominion filed applications with the Virginia Commission and the North Carolina Commission seeking approval to merge DNNA into Virginia Power. The Virginia and North Carolina applications were approved in July and September 2008, respectively, and DNNA was merged into Virginia Power effective December 1, 2008. Also in April 2008, Dominion filed an application with the NRC to transfer the ESP from DNNA to Virginia Power and ODEC. This application was approved in October 2008, and the ESP has been transferred to Virginia Power and ODEC.

In June 2008, the DOE issued a solicitation announcement inviting the submission of applications for loan guarantees from the DOE under its Loan Guarantee Program in support of debt financing for nuclear power facility projects in the U.S. (the Solicitation). The Solicitation is specifically designed to provide loan guarantees to support those projects that employ new or significantly improved nuclear power facility technologies. Any loan guarantee which may be issued by the DOE pursuant to the Solicitation would be backed by the full faith and credit of the U.S. government, and would provide credit enhancement for all or a portion of the debt financing an applicant would incur with respect to such a project. In August 2008, we submitted to the DOE Part I of the application, including a high-level description of the proposed nuclear unit, project eligibility, financing strategy and progress to date related to critical path schedules. In December 2008, we submitted to the DOE Part II of the application. DOE is in the process of evaluating our application, together with all other substantially completed applications submitted.

In March 2008, we purchased a power station development project in Buckingham County, Virginia (Bear Garden) that, once constructed, will generate about 590 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 need to be constructed to provide gas supply to the power station. In March 2008, we filed an application with the Virginia Commission for authority to build the proposed combined-cycle, natural gas-fired power station and transmission interconnection line for an estimated $619 million, excluding financing costs. Pending the receipt of regulatory approval, we expect operations to begin in the summer of 2011.

In March 2008, we also purchased a power station development project in Warren County, Virginia for future development. If developed, the project will involve the construction of a combined cycle, natural gas-fired power station expected to generate

about 600 Mw of electricity and will be subject to necessary regulatory approvals. In January 2009, we announced a joint effort with BP Alternative Energy, Inc. (BP) to evaluate wind energy projects in Tazewell County and Wise County, Virginia which, if completed, would increase our renewable energy capacity.

Sources of Energy Supply

We use a variety of fuels to power our electric generation and purchase power for system load requirements, as described below.

	2008 Source	2007 Source	2006 Source
Coal[1]	**33%**	35%	38%
Nuclear[2]	**31**	29	31
Purchased power, net	**29**	28	26
Natural gas	**6**	6	4
Oil	**1**	2	1
Total	**100%**	100%	100%

(1) Excludes ODEC s 50% ownership interest in the Clover Power Station. The average cost of coal for 2008 Virginia in-system generation was $28.02 per Mw hour.
(2) Excludes ODEC s 11.6% ownership interest in North Anna.

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. 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 through 2014. 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 from both domestic and international suppliers.

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 Generation typically vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. In addition, an increase in heating degree days does not produce the same increase in revenue as an increase in cooling degree days due to seasonal pricing differentials and because alternative heating sources are more readily available.

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NUCLEAR DECOMMISSIONING

Generation has a total of four licensed, operating nuclear reactors at its Surry power station (Surry) and North Anna, in Virginia, that serve customers of our regulated operations.

We have decommissioning obligations for each of these power stations, as discussed in Note 12 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.

While the current economic downturn has resulted in a decrease in the value of investments held by our nuclear decommissioning trusts, we continue to believe that the amounts currently available in our decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for our Surry and North Anna units especially when combined with ratepayer collections and contributions to the decommissioning trusts, if such future collections and contributions are required. This reflects our long-term investment horizon, since the units will not be decommissioned for decades, and our positive long-term outlook for trust fund investment returns. We will continue to monitor these trusts to ensure they meet the minimum financial assurance requirement, which may include the use of parent company guarantees, surety bonding or other financial guarantees recognized by the NRC.

The total estimated cost to decommission our four nuclear units is $2.0 billion in 2008 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:

(dollars in millions)	NRC license expiration year	Most recent cost estimate (2008 dollars)	Funds in trusts at December 31, 2008	2008 contributions to trusts
Surry				
Unit 1	**2032**	**$ 511**	**$ 296**	**$ 1.4**
Unit 2	**2033**	**540**	**292**	**1.5**
North Anna				
Unit 1	**2038**	**485**	**239**	**1.0**
Unit 2	**2040**	**507**	**226**	**0.9**
Total		**$ 2,043**	**$ 1,053**	**$ 4.8**

Corporate and Other

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

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 load management;
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 role in meeting the growing demand for electricity. Virginia re-regulation legislation enacted in 2007 provides 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. A description of our conservation and load management programs is detailed below.

We are working to improve our own energy efficiency, both in using less fuel to produce the same amount of energy and to use less energy in our operations. Recent uprates of our facilities have resulted in significant increases in generation capacity and a lower emitting fleet to meet the needs of our customers.

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting targets 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. We currently provide approximately two percent of our generation from renewable sources. We also anticipate using at least 10% biomass (wood waste) at the 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) emission 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 capture and storage. There is no current economically viable technological solution to retro-fit existing fossil-fueled technology to capture and store greenhouse gas (GHG) emissions. Given that new generation units have useful lives of up to 55 years, we will give full consideration to CO_2 and other GHG emissions when making long-term decisions. See *Generation Properties* for more information on generation expansion projects.

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. See also *Global Climate Change* under *Regulation* for additional information.

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Conservation and Load Management Programs

We have conducted a series of short-term pilot programs focused on energy conservation and demand response. The pilots were offered to a selection of 4,550 customers in our central, eastern and northern Virginia service areas. To help ensure that the results were representative, solicitations were given to select customers. No customer could participate in more than one pilot. We reported results from the pilots at least quarterly to the Virginia Commission staff to help evaluate their effectiveness. Most of these pilots had ended as of December 31, 2008.

The pilots approved by the Virginia Commission included:

- 1,000 residential customers in each of four different energy-saving pilots. The pilots were designed to cycle central 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 customer accounts received energy efficiency welcome kits.
- 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 is in addition to existing Dominion options in which commercial and industrial customers have reduced demand by more than 300 Mw during peak-demand periods.

In June 2008, we announced an energy conservation and load management plan that, if implemented, is expected to produce long-term environmental benefits while providing customers with cost savings. The plan is part of our *Powering Virginia* strategy to meet the future needs of customers. We expect to launch the plan in early 2010, subject to approval by the Virginia Commission and the North Carolina Commission, as applicable.

A key component of the plan is the potential installation of smart grid technologies that are designed to enhance our electric distribution system by allowing energy to be delivered more efficiently. Dependent upon the outcome of demonstration projects taking place in 2009, we expect to make a significant investment in replacing all of our existing meters with Advanced Metering Infrastructure (AMI). The technology is expected to lead to improvements in service reliability and the ability of customers to monitor and control their energy use. Additionally, programs in the conservation plan include:

- Incentives for construction of energy-efficient homes that meet the federal government s Energy Star® standards;
- Incentives for residential and commercial customers to install energy-efficient lighting;
- Energy audits and improvements for homes of low-income customers;
- Incentives for residential customers who voluntarily enroll to allow the Company to cycle their air-conditioners and heat pumps during periods of peak demand;
- In-home display devices that display the amount and cost of electricity customers are using; and
- Incentives for residential and commercial customers to improve the energy efficiency of their heating and/or cooling units.

REGULATION

We are subject to regulation by the Virginia Commission, North Carolina 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 other Dominion subsidiaries (affiliates), transfers of certain facilities and issuance of securities.

Status of Electric Regulation in Virginia

2007 Virginia Regulation Act and Fuel Factor Amendments

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

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

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

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level, such earnings will be shared with customers. If over-earning persists for two consecutive biennial periods, in addition to earnings sharing, rates may also be reduced.

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

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

Virginia Fuel Expenses

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

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

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

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

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

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

North Carolina Regulation

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

In September 2008, we filed an application to revise our fuel factor with the North Carolina Commission, requesting an annual increase in our North Carolina fuel factor from 2.221 cents per kWh to 3.825 cents per kWh to be effective January 1, 2009. The proposal would result in an annual increase in fuel revenue of approximately $69 million for the North Carolina jurisdiction. In December 2008, the Company, the Public Staff of the North Carolina Commission and other parties filed a proposed settlement that would increase our North Carolina fuel factor from 2.221 cents per kWh to 3.206 cents per kWh. The North Carolina Commission approved the settlement in December 2008. The resulting increase in annual fuel revenue is approximately $42 million for the North Carolina jurisdiction.

Federal Regulations

Federal Energy Regulatory Commission

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. We sell electricity in the 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 500 kV, 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 and the appeal is pending. We cannot predict the outcome of the appeal.

We are subject to FERC s Standards of Conduct that govern conduct between the transmission function employees interstate gas and electricity transmission providers and the marketing function employees of their affiliates. The rule defines the scope of transmission and marketing-related functions that are covered by the standards and is designed to prevent transmission providers from giving their affiliates undue preferences. We are also subject to FERC s affiliate restrictions that (1) prohibit power sales between us and Dominion s merchant plants without first receiving FERC authorization, (2) require us and Dominion s merchant plants to conduct our wholesale power sales operations separately, and (3) prohibit us from sharing market information with Dominion s merchant plant operating personnel. The rules are designed to prohibit us from giving Dominion s merchant plants a competitive advantage.

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 in June 2007, entities that violate standards will be subject to fines of between $1 thousand and $1 million per day, and can also be assessed 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.

In April 2008, FERC granted an application by our electric transmission operations to establish a forward-looking formula rate mechanism that will update transmission rates on an annual basis and approved an ROE of 11.4% on the common equity base of these operations, effective as of January 1, 2008. The formula rate is designed to cover the expected cost of service for each calendar year and will be trued up based on actual costs. While other transmission owners in the PJM region use a formula rate based on historic costs, our formula rate is based on projected

costs. The FERC ruling did not materially impact our results of operations; however, going forward the FERC-approved formula method will allow us to earn a more current return on our growing investment in electric transmission infrastructure.

In July 2008, we filed an application with FERC requesting a revision to our cost of service to reflect an additional ROE incentive adder for eleven electric transmission enhancement projects. Under the proposal, our cost of transmission service would increase to include an ROE incentive adder for each of the eleven projects, beginning the date each project enters commercial operation (but not before January 1, 2009). We proposed an incentive of 150 basis points or 1.5% for four of the projects (including the Meadow Brook-to-Loudoun line and Carson-to-Suffolk line) and an incentive of 125 basis points or 1.25% for the other seven projects. In August 2008, FERC approved our proposal, effective September 1, 2008. The total cost for all eleven projects is estimated at $877 million, and all projects are currently expected to be completed by 2012. Numerous parties sought rehearing of the FERC order in August 2008 and rehearing is pending. We cannot predict the outcome of the rehearing.

In May 2008, the Maryland Public Service Commission, Delaware Public Service Commission, Pennsylvania Commission, New Jersey Board of Public Utilities, the American Forest & Paper Association, the Portland Cement Association and several other organizations representing consumers in the PJM region (the RPM Buyers) filed a complaint at FERC claiming that PJM s Reliability Pricing Model s transitional auctions have produced unjust and unreasonable capacity prices. The RPM Buyers requested that a refund effective date of June 1, 2008 be established and that FERC provide appropriate relief from unjust and unreasonable capacity charges within 15 months. In September 2008, FERC dismissed the complaint. The RPM Buyers requested rehearing of the FERC order in October 2008 and rehearing is pending. We cannot predict the outcome of the rehearing.

In September 2008, we and Dominion filed a Deferral Recovery Charge (DRC) request with FERC to recover approximately $153 million of RTO costs ($140 million of our costs and $13 million of Dominion s costs) that we have been unable to recover due to a statutory base rate cap established under Virginia law. The RTO costs include:

(i) costs for development of the Alliance RTO on and after this base rate cap became effective on July 1, 1999;
(ii) costs to start up our participation in PJM; and
(iii) PJM administrative fees billed by PJM from the date that we joined PJM as a transmission owner.

In December 2008, FERC approved the DRC to become effective January 1, 2009, as requested. However, recovery of RTO costs through the DRC will not commence until the date established by the Virginia Commission that permits us to implement such recovery. In January 2009, requests for rehearing of the DRC by FERC were filed by the Virginia Commission and the Virginia Attorney General s office. We cannot predict the outcome of the rehearing.

Environmental Regulations

General

Both of our operating segments face substantial laws, regulations and compliance costs with respect to environmental matters. In

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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. We have applied for or obtained the necessary environmental permits for the operation of our facilities. Many of these permits are subject to reissuance and continuing review. 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 20 to our Consolidated Financial Statements.

AIR

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.

In March 2005, the EPA Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, if implemented, would require significant reductions in SO_2, nitrogen oxide (NO_X) and mercury emissions from electric generating facilities.

In February 2008, the D.C. Appeals Court issued a ruling that vacates CAMR as promulgated by the EPA. In May 2008, the EPA s appeal of this decision with the D.C. Appeals Court was denied. In September 2008, the Utility Air Regulatory Group filed a petition requesting that the U.S. Supreme Court review the D.C. Appeals Court decision to vacate the EPA rule. In October 2008, the Solicitor General, on behalf of the EPA, also filed a petition with the U.S. Supreme Court; however, in February 2009, it filed a motion to dismiss its petition. Also in February 2009 the U.S. Supreme Court denied the Utility Air Regulatory Group s petition. The EPA Administrator has announced that the EPA will proceed with a Maximum Achievable Control Technology rule-making. We cannot predict how the EPA or the states may alter their approach to reducing mercury emissions.

In July 2008, the D.C. Appeals Court issued a ruling vacating CAIR as promulgated by the EPA. A number of parties, including the EPA, filed petitions for a rehearing of the decision. The Court s decision resulted in a decline in the market value of SO_2 allowances that could have limited our ability to monetize the value of these allowances in the future. During the third quarter of 2008, we tested our SO_2 allowances for impairment and concluded that no impairment adjustment was required as a result of this decline in market value. In December 2008, the Court denied rehearing, but also issued a decision to remand CAIR to the EPA, so the CAIR rules remain in effect. The remand resulted in an increase in the market value of SO_2 allowances and allows CAIR to remain in place until such time that the EPA develops and implements a new rulemaking addressing the issues identified by the Court. We cannot predict how a new rulemaking will

impact future SO_2 and NO_X emission reduction requirements beyond CAIR.

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 other CAA required programs will generally address CAVR if those rules proceed, additional emission reduction requirements may be imposed on our facilities.

Implementation of projects to comply with 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 $260 million during the period 2009 through 2013.

WATER

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. In July 2004, the EPA published regulations under CWA 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 presented 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. In April 2008, the U.S. Supreme Court granted the industry request to review the question of whether Section 316b of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral arguments were presented before the U.S. Supreme Court in December 2008 with a decision expected in 2009. 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.

Solid and Hazardous Waste

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), provides for an immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at certain sites. These potentially responsible parties (PRPs) can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. Government concerning their

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liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, we may be identified as a PRP to a Superfund site. Refer to Note 20 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.

Global Climate Change

General

In recent years there has been increased national and international attention to GHG emissions and their relationship to climate change. We expect that there will be federal, regional or state legislative or regulatory action in this area in the near future. Dominion supports national climate change legislation to provide a consistent, economy-wide approach to addressing this issue and is taking action to protect the environment and address climate change while meeting the future needs of its growing service territory.

For Generation, our direct CO_2 emissions, based on ownership, were approximately 35 million metric tonnes in 2007. While we do not have final 2008 emissions data for Generation, we estimate that there will not be a significant variance in emissions from 2007 amounts. The emissions reported are for CO_2 directly emitted to the atmosphere based on the combustion of carbon-based fuels. Direct CO_2 emissions are provided based on emissions from primary stack and emissions from any auxiliary combustion equipment located at the electric generation facility. Primary facility stack emissions of CO_2 from carbon-based fuel combustion are directly measured via methods set forth under 40 CFR Part 75 of the United States Code (USC). For those emission sources not covered under 40 CFR Part 75 requirements, quantification is based on fuel combustion and emission factors consistent with industry best practices.

Climate Change Legislation

The new presidential administration and Congress bring expanded support for federal legislative action and regulatory initiatives for mandatory GHG emission reductions. The new presidential administration is expected to offer comprehensive legislation to establish an economy-wide program to significantly reduce GHG emissions. Other legislative efforts may propose reduction requirements measured against current emission levels. These proposals will possibly include some emission allowances allocated to major sectors of the economy covered by the legislation with a remaining amount of allowances auctioned to interested parties, both covered and non-covered sectors of the economy. Climate change legislation continues to evolve and accordingly, we cannot predict what, if any, legislation will ultimately pass.

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions, which could result in future EPA action. Possible outcomes from this decision include regulation of GHG emissions from various sources, including electric generation.

We currently support the enactment of federal legislation that regulates GHG emissions economy-wide, establishes a system of tradable allowances, slows the growth of GHG emissions in the near term and reduces GHG emissions in the long term. In addition, we support legislation that sets a realistic baseline year and

schedule and that is designed in a way to limit potential harm to the economy and competitive businesses.

In addition to possible federal action, some regions and states in which we operate have already or may adopt GHG emission reduction programs. For example, the Virginia Energy Plan, released by the Governor of Virginia in September 2007, includes a goal of reducing GHG emissions statewide back to 2000 levels by 2025. The Governor formed a Commission on Climate Change to develop a plan to achieve this goal. In November 2008, the Commission on Climate Change formulated their recommendations to the Governor.

The United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change and became effective for signatories on February 16, 2005. The Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008-2012 time period. At the conclusion of the December 2007 United Nations Climate Change Conference in Bali, Indonesia, the Bali Action Plan was adopted which identifies a timeline for the consideration of possible post-2012 international actions to further address climate change. The U.S. is expected to participate in this process.

The cost of compliance with future GHG emission 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 GHG emission reduction programs on our operations or our customers at this time.

Dominion s Strategy for Voluntarily Reducing CO_2 Emissions

While Dominion has not established a stand alone CO_2 emissions reduction target or timetable, we are actively engaged in voluntary reduction efforts and will work toward achieving the standards established by existing state regulations as set forth above. We have an integrated strategy for reducing CO_2 emission intensity that is based on maintaining a diverse fuel mix, including nuclear, coal, gas, hydro and renewable energy, investing in renewable energy projects, and promoting energy conservation and efficiency efforts. See *Environmental Strategy* above for a description of our strategy for reducing CO_2 emission intensity. Some recent efforts that have or are expected to reduce the Company s carbon intensity include:

In 2003, we retired two oil-fired units at our Possum Point Power Station, replacing them with a new 559 Mw combined cycle natural gas technology. We also converted two coal-fired units to cleaner burning natural gas.
Since 2000, we have added approximately 1,300 Mw of new lower-emitting natural gas-fired generation (excluding Possum Point) to our generation mix.
We have also added 83 Mw of renewable biomass.
In January 2009, we announced a joint effort with BP to evaluate wind energy projects in Tazewell County and Wise County, Virginia.
In December 2007, we announced that we had acquired a 590-Mw combined-cycle natural gas-fired development project in Buckingham County, Virginia (Bear Garden).
We have received an early site permit from the NRC for the possible addition of approximately 1,500 Mw of nuclear generation in Virginia.

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While, upon entering service, our new Virginia City Hybrid Energy Center which is currently under construction in Southwest Virginia will be a new source of GHG emissions, we have taken steps to minimize the impact on the environment. The new plant is expected to use at least ten percent biomass for fuel and was designed to be carbon-capture compatible, meaning that technology to capture CO_2 can be added to the station when it becomes commercially available. Also, we have announced plans to convert our coal units at Bremo Power Station to natural gas, contingent upon the Virginia City Hybrid Energy Center entering service and receipt of necessary approvals. See *Generation-Properties* for more information on the projects above, as well as other projects under current development.

Since 2000, we have tracked the emissions of our electric generation fleet. Our electric generation fleet employs a mix of fuel and renewable energy sources. Comparing annual year 2000 to annual year 2007, our electric generating fleet (based on our ownership percentage) reduced its average CO_2 emissions rate per megawatt- hour of energy produced from electric generation by about 3.5%. During such time period the capacity of our electric generation fleet has grown.

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, it 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 our decommissioning trusts, see *Generation Nuclear Decommissioning* and Note 8 to our Consolidated Financial Statements.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into a contract with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contract with the DOE. In January 2004, we filed a lawsuit in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. A trial occurred in May 2008 and post-trial briefing and argument concluded in July 2008. On October 15, 2008, the Court issued an opinion and order for us in the amount of approximately $112 million for our spent fuel-related costs through June 30, 2006, and judgment was entered by the Court on October 28, 2008. On December 24, 2008, the government appealed the judgment to the U. S. Court of Appeals for the Federal Circuit and the appeal was docketed on December 30, 2008. Briefing on the appeal is expected to take

place in 2009. Payment of any damages will not occur until the appeal process has been resolved. We cannot predict the outcome of this matter; however, in the event that we recover damages, such recovery, including amounts attributable to joint owners, is not expected to have a material impact on our results of operations. We will continue to manage our spent fuel until it is accepted by the DOE.

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 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. Additionally, 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.

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 condition, 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 CO_2 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 CO_2 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 GHG 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 is significant advancement in the commercial availability and cost of carbon capture and storage technology. In addition, a number of bills have been introduced in Congress that would require GHG emission 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 GHG emission reduction requirements may require us to commit significant capital toward carbon capture and storage technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and potential replacement with lower emitting generation facilities. The cost of compliance with expected GHG emission legislation is 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 storage 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.

Our base rates are subject to regulatory review. As a result of the Regulation 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 structure, as reviewed and approved in regulatory proceedings. Under the Regulation Act, the Virginia Commission may, in a proceeding conducted in 2009, reduce rates or order a credit to customers if we are deemed to be earning more than 50 basis points above an ROE level to be established by the Virginia Commission in that proceeding. After the initial rate case, the Virginia Commission will review our base rates biennially and may order a credit to customers if we are deemed to have earned an ROE more than 50 basis points above an ROE level established by the Virginia Commission and may reduce rates if we are found to have had earnings in excess of the established ROE level during two consecutive biennial review periods.

Delays in the recovery of fuel costs could negatively affect our cash flow, which could adversely affect our results of operations. We have a statutory right to recover from customers all prudently incurred fuel costs through fuel factors which have been implemented in our Virginia and North Carolina jurisdictions. However, as a result of increasing fuel costs and a statutory limitation on the amount of fuel recovery that could be collected from Virginia jurisdictional customers in the July 1, 2007 through June 30, 2008 fuel factor period, we have deferred a significant amount of fuel costs. Deferred recovery of fuel costs could have a negative impact on our cash flow. The recent fluctuations in fuel prices may make it difficult to accurately predict fuel costs. In the future, if actual fuel costs incurred during the fuel factor period exceed the estimate of costs which the Virginia Commission has approved for recovery in that period, we will not have authority to recover the excess costs through fuel rates until the following year when a new factor is determined. To the extent that such deferrals occur, the resulting delays in the current recovery of fuel costs could negatively impact our cash flow, which could adversely affect our results of operations.

The rates of our electric transmission operations are subject to regulatory review. Revenue provided by our electric transmission operations is based primarily on rates approved by FERC. The profitability of this businesses is dependent on our ability, through the rates that we are permitted to charge, to recover costs and earn a reasonable rate of return on our capital investment. Our wholesale charges for electric transmission service are adjusted on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism our wholesale electric transmission cost of service is estimated and thereafter trued-up as appropriate to reflect actual costs allocated to the Company by PJM. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that our wholesale revenue requirement is no longer just and reasonable.

Energy conservation could negatively impact our financial results. Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by a fixed date. 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.

Our operations could be affected by terrorist activities and catastrophic events that could result from terrorism. In the event that our generating facilities or other infrastructure assets are subject to potential terrorist activities, such activities could significantly impair our operations and result in a decrease in revenues and additional costs to repair and insure our assets, which could have a material adverse effect on our business. The effects of potential terrorist activities could also include the risk of a significant decline in the U.S. economy, and the decreased availability and increased cost of insurance coverage, any of which effects could negatively impact our operations and financial condition.

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We have incurred increased capital and operating expenses and may incur further costs for enhanced security in response to such risks.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including 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 (FTRs) 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 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 several plant construction and expansion projects and may consider additional 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 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, a decline in the credit strength of our

counterparties or vendors, or other factors beyond our control. Even if plant construction and expansion projects are completed, the total costs of the projects may be higher than anticipated and the performance of our business following the projects may not meet expectations. Additionally, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Further, we may not be able to timely and effectively integrate the projects into our operations and 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 funding and liquidity for capital expenditures and normal working capital. Management believes that we will maintain sufficient access to these financial markets based upon our current credit ratings and market reputation. 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 a continuation of the current economic downturn, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, changes to our credit ratings or the failure of financial institutions on which we rely. 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, 2009, 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 A-, 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 Indenture of Mortgage securing any of our First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2008, however; by leaving the indenture open we retain the flexibility to issue mortgage 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.

Power Generation

Our Generation segment provides electricity for use on a wholesale and a retail level. Our Generation segment supplies electricity demand either from our generation facilities in Virginia, North Carolina and West Virginia or through purchased power contracts.

The following table lists our Generation segment s generating units and capability, as of December 31, 2008:

Plant	Location	Net Summer Capability (Mw)	Percentage Net Summer Capability
Coal			
Mt. Storm	Mt. Storm, WV	1,560	
Chesterfield	Chester, VA	1,235	
Chesapeake	Chesapeake, VA	595	
Clover	Clover, VA	433[(a)]	
Yorktown	Yorktown, VA	323	
Bremo	Bremo Bluff, VA	227	
Mecklenburg	Clarksville, VA	138	
North Branch	Bayard, WV	74	
Altavista	Altavista, VA	63	
Polyester[(b)]	Hopewell, VA	63	
Southampton	Southampton, VA	63	
Total Coal		4,774	26%
Gas			
Ladysmith (CT)	Ladysmith, VA	623	
Remington (CT)	Remington, VA	608	
Possum Point (CC)	Dumfries, VA	559	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point	Dumfries, VA	316	
Bellemeade (CC)	Richmond, VA	245	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Gravel Neck (CT)	Surry, VA	158	

Total Gas		3,805	21
Nuclear			
Surry	Surry, VA	1,598	
North Anna	Mineral, VA	1,596(c)	
Total Nuclear		3,194	18
Oil			
Yorktown	Yorktown, VA	818	
Possum Point	Dumfries, VA	786	
Gravel Neck (CT)	Surry, VA	186	
Darbytown (CT)	Richmond, VA	168	
Chesapeake (CT)	Chesapeake, VA	115	
Possum Point (CT)	Dumfries, VA	72	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Kitty Hawk (CT)	Kitty Hawk, NC	31	
Total Oil		2,271	13

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Plant	Location		Net Summer Capability (Mw)	Percentage Net Summer Capability
Hydro				
Bath County	Warm Springs, VA		1,754(d)	
Gaston	Roanoke Rapids, NC		220	
Roanoke Rapids	Roanoke Rapids, NC		95	
Other	Various		3	
Total Hydro			2,072	11
Biomass				
Pittsylvania	Hurt, VA		83	1
Various				
Other	Various		11	---
			16,210	
Power Purchase Agreements			1,860	10
		Total Capability	18,070	100%

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

(a) Excludes 50% undivided interest owned by ODEC.
(b) Previously referred to as Hopewell.
(c) Excludes 11.6% undivided interest owned by ODEC.
(d) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

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 20 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 *Dividend Restrictions* in Item 7. MD&A and Note 18 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
2008	**$ 115**	**$ 83**	**$ 163**	**$ 80**	**$ 441**
2007	77	65	196	39	377

Item 6. Selected Financial Data

Year Ended December 31, (millions)	**2008**	2007	2006	2005(1)	2004(2)
Operating revenue	**$ 6,934**	$ 6,181	$ 5,603	$ 5,712	$ 5,371
Income from operations before extraordinary item and cumulative effect of changes in accounting principles	**864**	606	478	485	590
Loss from discontinued operations, net of tax(3)				(471)	(159)
Extraordinary item, net of tax(4)		(158)			
Cumulative effect of changes in accounting principles, net of tax				(4)	
Net income	**864**	448	478	10	431
Balance available for common stock	**847**	432	462	(6)	415
Total assets	**18,802**	17,063	15,683	15,449	17,334
Long-term debt	**6,000**	5,316	3,619	3,888	4,958

(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.

(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) Reflects the net impact of the discontinued operations of our indirect wholly-owned subsidiary, Virginia Power Energy Marketing, Inc., which was transferred to Dominion through a series of dividend distributions on December 31, 2005.

(4) 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

MD&A discusses our results of operations and general financial condition. MD&A should be read in conjunction with Item 1. Business and our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

CONTENTS OF MD&A

Our MD&A consists of the following information:

FORWARD-LOOKING STATEMENTS

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and severe 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, GHG emissions and other emissions 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;
- Capital market conditions, including the availability of credit and our ability to obtain financing on reasonable terms;
- Risks associated with our membership and participation in PJM related to obligations created by the default of other participants;
- Price risk due to securities held as investments in nuclear decommissioning trusts;
- Fluctuations in interest rates;
- Changes in federal and state tax laws and regulations;

Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
Changes to regulated electric rates collected by the Company, including the outcome of our 2009 base rate review, and the timing of such collection as it relates to fuel costs;
Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;
The inability to complete planned construction or expansion projects within the terms and time frames initially anticipated;
Changes in rules for the RTO in which we participate, including changes in rate designs and capacity models;
Political and economic conditions, including the threat of domestic terrorism, inflation and deflation; and
Adverse outcomes in litigation matters.

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.

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 Derivative Contracts and Other Instruments at Fair Value

We use derivative contracts such as futures, swaps, forwards, options and FTRs to manage the commodity and financial markets risks of our business operations. Derivative contracts, with certain exceptions, are subject to fair value accounting, as prescribed by SFAS No. 157, *Fair Value Measurements* and are reported in our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies. The majority of investments held in nuclear decommissioning trust funds are also subject to fair value accounting. See Note 8 of our Consolidated Financial Statements for further information on our fair value measurements.

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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, or if we believe that observable pricing information is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases we must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis, that reflect our market assumptions.

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

In accordance with SFAS No. 157, we maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We utilize the following fair value hierarchy as prescribed by SFAS No. 157, which categorizes the inputs used to measure fair value into three levels:

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

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

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

Fair value measurements are categorized as Level 3 when a significant amount of price or other inputs that are considered to be unobservable are used in their valuations. Long-dated commodity derivatives are based on unobservable inputs due to

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

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

SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of our own nonperformance risk on our liabilities. We apply credit adjustments to our derivative fair values in accordance with the guidance in SFAS No. 157. These credit adjustments are currently not material to our derivative fair values.

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

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 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 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 11 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 cost escalation 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 2008, 2007 and 2006, we recognized $38 million, $38 million and $40 million, respectively, of accretion and expect to incur $40 million in 2009. 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, 2008, nuclear decommissioning AROs, which are reported in the Generation segment, totaled $673 million, representing approximately 94% of our total AROs. Based on their significance, the following discussion of critical assumptions inherent in determin-

ing 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, 2008, for our AROs related to nuclear decommissioning would have been $123 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 $341 million and $270 million of accrued unbilled revenue at December 31, 2008 and 2007, respectively.

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

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret 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 FIN 48, *Accounting for Uncertainty in Income Taxes*.

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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, 2008, we had $180 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, 2008, we had no valuation allowances on our deferred tax assets.

Other

Accounting Standards and Policies

During 2008, 2007 and 2006, 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.

In the fourth quarter of 2008, we revised our derivative income statement classification policy, described in Note 2 to our Consolidated Financial Statements, to present income statement activity for all non-trading derivatives based on the nature of the underlying risk. This includes unrealized changes in the fair value of and settlements of financially-settled derivatives not held for trading purposes, as well as gains or losses attributable to ineffectiveness, changes in the time value of options, and discontinuances of hedging instruments, all of which were previously presented in other operations and maintenance expense on a net basis. Our prior year Consolidated Statements of Income have been recast to conform to the 2008 presentation; however, this had no impact on earnings.

Results of Operations

Presented below is a summary of our consolidated results:

Year Ended December 31, (millions)	**2008**	**$ Change**	2007	$ Change	2006
Net Income	**$ 864**	**$ 416**	$ 448	$ (30)	$ 478

Overview

2008 vs. 2007

Net income increased 93% to $864 million, primarily due to the reinstatement of annual fuel rate adjustments for the Virginia jurisdiction of our generation operations effective July 1, 2007, with deferred fuel accounting for over- or under-recoveries of fuel costs, and the absence of an extraordinary charge incurred in 2007 in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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 for the Virginia jurisdiction of our generation operations.

Analysis of Consolidated Operations

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

Year Ended December 31, (millions)	**2008**	**$ Change**	2007	$ Change	2006
Operating Revenue	**$ 6,934**	**$ 753**	$ 6,181	$ 578	$ 5,603
Operating Expenses					
Electric fuel and energy purchases	**2,683**	**322**	2,361	128	2,233
Purchased electric capacity	**410**	**(19)**	429	(24)	453
Other energy-related commodity purchases	**24**	**(3)**	27	(29)	56
Other operations and maintenance	**1,405**	**8**	1,397	218	1,179
Depreciation and amortization	**608**	**40**	568	32	536
Other taxes	**183**	**10**	173	10	163
Other income	**52**	**(3)**	55	(20)	75
Interest and related charges	**309**	**5**	304	8	296
Income tax expense	**500**	**129**	371	87	284
Extraordinary item, net of tax		**158**	(158)	(158)	

An analysis of our results of operations for 2008 compared to 2007 and 2007 compared to 2006 follows:

2008 vs. 2007

Operating Revenue increased 12% to $6.9 billion, primarily reflecting the combined effects of:

- A $722 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions;
- An $84 million increase associated with sales to wholesale customers primarily due to higher prices ($46 million) and increased volumes ($38 million); and

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- A $56 million increase in new retail customer connections primarily in our residential and commercial customer classes; partially offset by
- A $95 million decrease in sales to retail customers due to a 10% decrease in cooling degree days and a 2% decrease in heating degree days.

Operating Expenses and Other Items

Electric fuel and energy purchases expense increased 14% to $2.7 billion, primarily reflecting a $434 million increase in fuel costs, largely as a result of higher commodity prices, including purchased power, partially offset by a $113 million decrease due to the deferral of fuel expenses that were in excess of the fuel rate recovery.

Other operations and maintenance expense increased 1% to $1.4 billion, primarily reflecting:

- A $69 million increase resulting from higher salaries, wages and other benefits expenses and other general and administrative costs; partially offset by
- A $58 million decrease in outage costs resulting from a reduction in scheduled outages at certain of our electric generating facilities.

Depreciation and amortization expense increased 7% to $608 million, primarily due to an increase in depreciation rates for our generation assets ($36 million), and property additions ($15 million), partially offset by an $11 million decrease in amortization expense primarily associated with lower consumption of emissions allowances.

Interest and related charges increased 2% to $309 million, primarily due to a $43 million impact from additional borrowings, partially offset by a $23 million benefit related to the redemption of our Callable and Puttable Enhanced Securities (CAPES) and lower interest rates on variable rate debt ($15 million). See Note 15 to our Consolidated Financial Statements for additional information on the CAPES.

Income tax expense increased 35% to $500 million, reflecting higher pre-tax income in 2008.

Extraordinary item reflects the absence of a $158 million after-tax charge in 2007 in connection with the reapplication of SFAS No. 71 to the Virginia jurisdiction of our generation operations.

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 implemented in July 2007, for 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 primarily due to increased volumes; 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 6% to $2.4 billion, primarily reflecting a $536 million increase in underlying fuel costs, including those subject to deferral accounting 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 18% to $1.4 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, finance and certain administrative and technical services to us; 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 ($12 million), a change in depreciation rates for our generation assets to reflect the results of a new depreciation study ($10 million) and increased amortization expense associated with emissions allowances held for consumption ($10 million).

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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Outlook

We believe our operating businesses will provide stable growth in net income in 2009. Our expected results for 2009 include the following growth factors:

- An increase in earnings assuming an increase in base rates resulting from the 2009 base rate review, normal weather in our utility service territory, rate adjustments for certain generation and transmission expansion projects and continued growth in sales. Despite the recent economic downturn we expect continued growth in sales due to several factors including our limited exposure to industrial customers, an unemployment rate in Virginia that is below the national average, a growing number of energy-intensive computer data centers and significant government presence in our Northern Virginia service territory and U.S. military base closures and reassignments that have resulted in personnel being shifted to facilities in Virginia such as Fort Lee and Fort Belvoir.

The increase in 2009 is expected to be partially offset by:

- Higher interest expense reflecting difficult credit market conditions; and
- An increase in costs for Dominion-sponsored employee pension and other postretirement benefit plans, in which our employees participate, largely reflecting the impact of 2008 declines in the market values of investments held to fund these obligations.

SEGMENT RESULTS OF OPERATIONS

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

Year Ended December 31, (millions)	**2008**	**$ Change**	2007	$ Change	2006
DVP	**$ 307**	**$ (35)**	$ 342	$ 3	$ 339
Generation	**583**	**307**	276	125	