VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

March 30, 1998

Director of Nuclear Reactor Regulation
United States Nuclear Regulatory Commission
Washington, DC 20555

Serial No.: 98-045
NLOS/MM
Docket Nos.: 50-280/281
50-338/339
License Nos.: DPR-32/37
NPF-4/7

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
NORTH ANNA POWER STATION UNITS 1 AND 2
PRICE-ANDERSON ACT

Pursuant to 10 CFR 140.21(e) regarding guarantees of payment of deferred premiums, we are providing the following information:

1. Comparative Statements of Income for the three months ended December 31, 1997 and 1996.

2. Internal cash flow projection for calendar year 1998 with certification by an officer of the Company.

3. Statement ensuring availability of funds for payment of retrospective premiums without curtailment of required nuclear construction expenditures.

4. A copy of the Annual Report to Securities and Exchange Commission on Form 10-K for 1997.

In accordance with 10 CFR 140.7, we submitted a check to the NRC for $1,000 on November 7, 1997, which is the minimum required premium for the period November 15, 1997 through November 14, 1998.

Very truly yours,

James P. O'Hanlon

James P. O'Hanlon
Senior Vice President - Nuclear

Enclosures

1/1
M001

cc: U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth St., SW, Suite 23T85
Atlanta, GA 30303

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Mr. R. A. Musser
NRC Senior Resident Inspector
Surry Power Station

Mr. M. J. Morgan
NRC Senior Resident Inspector
North Anna Power Station

50-280 VP SURRY 1

PRICE-ANDERSON ACT

REC'D W?LTR DTD 03/30/98....9804080248

VIRGINIA ELECTRIC & POWER COMPANY
STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended December 31, 1997	1996
	(Millions)	
Revenues:		
Electric service	$ 1,000.9	$ 964.4
Other	351.9	73.9
Total	1,352.8	1,038.3
Expenses:		
Fuel, net	515.0	261.2
Purchased power capacity, net	175.4	161.5
Operations and maintenance	208.0	209.6
Depreciation and amortization	157.6	126.0
Restructuring	7.3	0.0
Accelerated cost recovery	10.6	62.4
Amortization of terminated construction project costs	8.6	8.6
Taxes other than income	65.1	60.0
Total	1,147.6	889.3
Income from operations	205.2	149.0
Other income	1.9	(2.1)
Income before interest and income taxes	207.1	146.9
Interest and related charges:		
Interest expense, net	77.1	75.7
Distribution - preferred securities of subsidiary trust	2.7	2.7
Total	79.8	78.4
Income before income taxes	127.3	68.5
Income taxes	41.9	22.7
Net income	85.4	45.8
Preferred dividends	9.0	8.9
Balance available for Common Stock	$ 76.4	$ 36.9

Virginia Electric & Power Company
1998 Estimated Internal Cash Flow

(Millions of Dollars)

	Jan thru Mar	Apr thru Jun	Jul thru Sep	Oct thru Dec	Estimated 1998 Total
Cash Receipts	$1,472.8	$1,247.8	$1,517.7	$1,416.5	$5,654.8
Less:					
Cash for Operations	889.0	812.1	918.7	946.6	3,566.4
Taxes	34.5	191.0	126.1	181.6	533.2
Interest	78.0	66.0	82.6	58.0	284.6
Dividends	111.8	111.6	111.6	111.4	446.4
Decommissioning Trust	11.9	11.9	11.9	11.9	47.6
Changes in Working Capital	30.6	0.1	30.2	20.2	80.9
Total Cash Flow (1)	$317.0	$55.1	$236.6	$86.8	$695.7

(1) Before Financing and Construction Requirements.

VIRGINIA ELECTRIC AND POWER COMPANY
STATEMENT

The Company currently estimates 1998 construction and nuclear fuel expenditures (exclusive of Allowance for Funds Used During Construction) to be $588.1 million. Debt maturities in 1997 will total $333.5 million. It is expected that approximately $695.7 million will be obtained from internal sources. The remaining $225.9 of capital requirements will be obtained by a combination of sales of securities and short-term borrowings. The Company is reasonably assured that, based on the best available cash flow projections which are provided herewith, curtailment of capital expenditures for required nuclear programs would not be required to cover the Price-Anderson maximum retrospective premium assessment for a single incident of $326.8 million ($81.7 million, including a 3 percent insurance premium tax for Virginia, for each of the four reactors owned by the Company with assessments not to exceed $10.3 million per reactor per year) currently in force.

VIRGINIA ELECTRIC AND POWER COMPANY
CERTIFICATE

I, the undersigned M. S. Bolton, Jr., do hereby certify, pursuant to the guarantee requirements set forth in the Commission's letter dated June 15, 1977, that the cash flow projection for 1998, provided herewith, is based on the best available information known at this time and is a reasonably accurate projection of the Company's 1998 cash flow.

M S Bolton

M. S. Bolton, Jr.
Controller

Commonwealth of Virginia

City of Richmond

Sworn to and subscribed before me
this 25 day of March 1998.

K Lee Pace

Notary Public

My commission expires: 6-30-99

NOTARIAL SEAL

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1997
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 1-2255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

VIRGINIA	**54-0418825**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification no.)*
701 East Cary Street Richmond, Virginia	**23219-3932**
(Address of principal executive offices)	*(Zip Code)*

(804) 771-3000
(Registrant's telephone number, including area code)

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 liquidation value: $5.00 dividend	New York Stock Exchange
Trust Preferred Securities $25 liquidation value: 8.05% dividend	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

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 ☒ 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. ☐

The aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 1998, was zero.

As of February 28, 1998, there were issued and outstanding 171,484 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

VIRGINIA ELECTRIC AND POWER COMPANY

PART I

ITEM 1. BUSINESS
THE COMPANY

Virginia Electric and Power Company is a Virginia Corporation. Our principal office is at 701 East Cary Street, Richmond, Virginia 23219-3932, telephone (804) 771-3000. We are a wholly owned subsidiary of Dominion Resources, Inc. (Dominion Resources), a Virginia corporation. Dominion Resources owns all of our common stock.

Virginia Electric and Power Company is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy within a 30,000 square-mile area in Virginia and northeastern North Carolina. It transacts business under the name Virginia Power in Virginia and under the name North Carolina Power in North Carolina. We have retail customers (including governmental agencies) and wholesale customers such as rural electric cooperatives, power marketers and municipalities. We serve more than 80 percent of Virginia's population. The Company has certificates of convenience and necessity from the State Corporation Commission of Virginia (the Virginia Commission) for service in all territories served at retail in Virginia. The North Carolina Utilities Commission (the North Carolina Commission) has assigned territory to the Company for substantially all of its retail service outside certain municipalities in North Carolina.

The electric utility industry in the United States is undergoing an evolutionary change toward less regulation and more competition. To meet the challenges of this new competitive environment, Virginia Power has developed a broad array of "non-traditional" product and service offerings from its operating business units and subsidiaries:

- Energy Services — offering electric energy and capacity in the emerging wholesale market as well as natural gas and other energy-related products and services;
- Fossil & Hydro — targeting process type industries, such as chemical, paper, plastics and petroleum to become a service provider of instrumentation equipment;
- Nuclear Services — offering management and operations services to other electric utilities;
- Commercial Operations — providing power distribution related services, including transmission and distribution, engineering and metering services to other gas, water and electric utilities; and
- Telecommunications — offering telecommunications services through the Company's existing fiber-optic network.

The Company and its subsidiaries had 9,043 full-time employees on December 31, 1997. A total of 3,452 of our employees are represented by the International Brotherhood of Electrical Workers under a contract extending to March 31, 1998. The Company and the union have tentatively agreed, subject to ratification by the union membership, to a two year extension of the contract.

For a more thorough review of the changing utility industry and the Company's strategy see COMPETITION AND STRATEGIC INITIATIVES below and Future Issues — *Competition* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A).

COMPANY MANAGEMENT

In April, Dr. James T. Rhodes, President and Chief Executive Officer since 1989, announced his retirement effective August 1, 1997. The Board of Directors subsequently elected Mr. Norman Askew as the new President and Chief Executive Officer, effective August 1, 1997. Mr. Askew was previously the Chief Executive of East Midlands Electricity plc, a United Kingdom regional electricity company acquired by Dominion Resources during the first quarter of 1997. Mr. Askew also replaced Dr. Rhodes on the Board of Directors effective August 1, 1997.

COMPETITION AND STRATEGIC INITIATIVES

A number of developments in the United States are causing a trend toward less regulation and more competition in the electric utility industry. This is evidenced by legislative and regulatory action at both the federal and state levels. To the extent that competition is either authorized or mandated and regulation is eliminated or relaxed, electric utilities may no longer be guaranteed an opportunity to recover all of their prudently incurred costs, and utilities with costs that exceed the market prices established by the competitive market will run the risk of suffering losses, which may be substantial.

Virginia Power has responded to these trends by undertaking cost-cutting measures, engaging in re-engineering efforts, restructuring its core business processes, and pursuing a strategic planning initiative to encourage innovative approaches to serving traditional markets. The Company has established separate business units, as discussed above, to fully execute these strategies.

The Company also is vigorously participating in the state and federal legislative actions currently underway to bring about competition in the electric utility industry, in an effort to ensure an orderly transition from a regulated environment.

The Company's non-traditional businesses face competition from a variety of utility and non-utility entities.

For a full discussion of the regulatory and legislative issues related to competition, carefully read the Future Issues section of MD&A.

REGULATION

General

In a wide variety of matters in addition to rates, Virginia Power is presently subject to regulation by the Virginia Commission and the North Carolina Commission, the Environmental Protection Agency (EPA), Department of Energy (DOE), Nuclear Regulatory Commission (NRC), the Federal Energy Regulatory Commission (FERC), the Army Corps of Engineers, and other federal, state and local authorities. Compliance with numerous laws and regulations increases the Company's operating and capital costs by requiring, among other things, changes in the design and operation of existing facilities and changes or delays in the location, design, construction and operation of new facilities. The commissions regulating the Company's rates have historically permitted recovery of such costs.

Virginia Power 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 governmental agencies. Such approvals relate to, among other things, the environmental impact of such activities, the relationship of such activities to the need for providing adequate utility service and the design and operation of proposed facilities.

Both federal and state legislative bodies have been studying competition and restructuring in the electric utility industry. Please carefully read the full discussion of this matter found in the Future Issues — *Competition — Legislative Initiatives* section of MD&A.

Virginia

In 1995, the Virginia Commission instituted an ongoing generic investigation on electric industry restructuring, resulting in a number of reports by its Staff covering such issues as retail wheeling experiments and the status of wholesale power markets. The Staff also submitted a report to the General Assembly calling for a cautious, two-phase, five-year period to address restructuring issues. The report acknowledged the need for direction from the Virginia legislature concerning policy issues surrounding competition in the electric industry.

In November 1996, the Virginia Commission instituted a proceeding concerning Virginia Power's cost of service and possible restructuring of the electric utility industry as it might relate to Virginia Power. On March 24, 1997, Virginia Power filed in that proceeding a calculation of its cost of service for 1996 and a proposed Alternative Regulatory Plan (ARP). Subsequently, the Commission consolidated this proceeding with the proceeding concerning the Company's 1995 Annual Informational Filing, in which the Company's base rates were made interim and subject to refund as of March 1, 1997. Please carefully read the Future Issues — *Competition — Legislative and Regulatory Initiatives* sections of MD&A and RATES-Virginia, below for details concerning the ARP, its current status and related legislative developments.

In December 1995, Virginia Power applied to the Virginia Commission for approval of arrangements with Chesapeake Paper Products Company (CPPC), under which Virginia Power would facilitate the design, construction and financing of a cogeneration plant to meet CPPC's energy requirements for its industrial processes at its plant in West Point, Virginia. On August 13, 1997, the Virginia Commission approved, in substantial part, the proposed transactions between Virginia Power and CPPC's successor in ownership, St. Laurent Paper Products Co. St. Laurent later determined that the current design of the facility was no longer compatible with its long-term business strategies and terminated its contractual arrangement with Virginia Power. The Virginia Commission dismissed the proceeding on January 15, 1998.

In June 1997, the Virginia Commission granted the Company's request to implement a monitoring program that requires certain non-utility generators to provide certain information sufficient to determine continued compliance with the "Qualifying Facility" (QF) requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA).

On August 8, 1997, the Virginia Commission granted the Company's request to provide interchange telecommunications services and approved the proposed affiliate agreements between Virginia Power and our wholly-owned subsidiary, VPS Communications, Inc. (VPSC). Under the authority granted, VPSC will provide a range of telecommunications services, including private line and special access services and high-capacity fiberoptic services.

On September 3, 1997, the Virginia Commission granted the Company's request to provide services to our wholly-owned subsidiary, Virginia Power Services, Inc. (VPS), which would enable Virginia Power Nuclear Services Company (VPN), a VPS subsidiary, to furnish nuclear management and operation services to electric utilities seeking assistance in the management and operation of their nuclear generating facilities. VPN currently provides such services to Northeast Utilities at its Millstone Unit 2 nuclear plant.

FERC

In April 1996, FERC issued final rules in Order Nos. 888 and 889 addressing open access transmission service, stranded costs, standards of conduct and open access same-time information systems (OASIS). In July 1996, Virginia Power filed an open access transmission service tariff in compliance with FERC's Order No. 888. In compliance with FERC's directive, Virginia Power's OASIS became operational on January 3, 1997. Also, on that date the standards of conduct requiring separation of transmission operations/reliability functions from wholesale merchant/marketing functions became effective. The Company also made filings to comply with FERC's directive that, effective January 1, 1997, utilities could no longer make bundled sales of transmission and generation services in economy energy transactions. In certain of those filings, Virginia Power canceled or committed not to use the economy energy rate schedules contained in interconnection agreements with neighboring utilities. On March 4, 1997, FERC issued Order Nos. 888-A and 889-A, which addressed requests for rehearing of Order Nos. 888 and 889. Orders No. 888-A and 889-A essentially reaffirm the basic principles of 888 and 889 and clarify and make limited modifications to those orders. On December 17, 1997, FERC issued Order Nos. 888-B and 889-B. FERC rejected all requests for rehearing filed with respect to Order Nos. 888-A and 889-A and clarified and made limited modifications to those orders. Several parties have appealed the 888 orders to the United States Court of Appeals for the District of Columbia Circuit.

For a discussion of the status of the Company's Open Access Transmission Tariff filing, see RATES — FERC below.

For additional discussion of open access issues see Future Issues — *Competition* under MD&A.

LG&E Westmoreland Southampton owns a cogeneration facility in Franklin, Virginia, and sells its output to Virginia Power. Southampton has sought a waiver of FERC operating requirements for Qualifying Facilities (QF's) under PURPA, however FERC refused to grant such a waiver. On March 31, 1997, the United States Court of Appeals for the District of Columbia Circuit granted FERC's motion to dismiss Southampton's Petition for Review.

Environmental

From time to time, Virginia Power may be designated by the EPA as a potentially responsible party (PRP) with respect to a Superfund site. As a result of that designation or other regulations regarding the remediation of waste, we may become obligated to fund remedial investigations or actions. We do not believe that any currently identified sites will result in significant liabilities. For a discussion of the Company's site remediation efforts, see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS.

Permits under the Clean Water Act and state laws have been issued for all of the Company's steam generating stations now in operation. These permits are subject to reissuance and continuing review. The Clean Air Act, as amended in 1990, requires the Company to reduce its emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Beginning in 1995, the SO_2 reduction program is based on the issuance of a limited number of SO_2 emission allowances, each of which may be used as a permit to emit one ton of SO_2 into the atmosphere or may be sold to someone else. The program is administered by the EPA.

For additional information on Environmental Matters, Clean Air Act compliance and related issues see the Future Issues section of MD&A.

Nuclear

All aspects of the operation and maintenance of the Company's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and 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 the Company's nuclear generating units.

In July 1995, the Virginia Commission instituted an investigation regarding spent nuclear fuel disposal. As directed, Virginia Power and others filed comments on legal and public policy issues related to spent nuclear fuel storage and disposal. In February 1996, the Commission Staff filed its Report recommending that adoption of a definitive policy on spent nuclear fuel disposal issues be delayed pending the outcome of litigation against the Department of Energy concerning spent nuclear fuel acceptance, the outcome of proposed federal legislation concerning development of an interim storage facility, and development of a vision of the likely outcome of the electric utility industry's restructuring efforts. The Virginia Commission consolidated the proceeding with Virginia Power's pending fuel cost recovery proceeding in October 1996. On March 20, 1997, the Virginia Commission returned the spent nuclear fuel disposal issue to a separate proceeding.

On January 31, 1997, Virginia Power joined thirty-five other electric utilities in filing a petition in the United States Court of Appeals for the District of Columbia Circuit, seeking to compel DOE to comply with its obligation to begin accepting the utilities' spent nuclear fuel for disposal by January 31, 1998, the date imposed by the Nuclear Waste Policy Act. Additional utilities have joined since the original filing. On November 14, 1997, the Court issued an Order finding that DOE's obligation to begin accepting spent nuclear fuel by the deadline is unconditional, and that DOE may not excuse its delay on the grounds that it has not prepared a permanent repository or interim storage facility. The Court found that DOE's spent fuel disposal contracts with the utilities offer a potentially adequate remedy for DOE's failure to meet its obligation. DOE filed a petition for rehearing on December 29, 1997.

RATES

The Company's electric services sales were subject to rate regulation in 1997 as follows:

		1997	
		Percent of Revenues	Percent of Kwh Sales
Virginia retail:			
Non-Governmental customers	Virginia Commission	81%	76%
Governmental customers	Negotiated Agreements	10	12
North Carolina retail	North Carolina Commission	5	5
Wholesale —Sales for Resale*	FERC	4	7
		100%	100%

* Excludes wholesale power marketing sales subject to FERC regulation.

Substantially all of the Company's electric service sales are subject to recovery of changes in fuel costs either through fuel adjustment factors or periodic adjustments to base rates, each of which requires prior regulatory approval.

Each of these jurisdictions has the authority to disallow recovery of costs it determines to be excessive or imprudently incurred. Various cost items may be reviewed on occasion, including costs of constructing or modifying facilities, on-going purchases of capacity or providing replacement power during generating unit outages.

FERC

In compliance with FERC's Order No. 888, Virginia Power filed an open access transmission service tariff, which became effective on July 9, 1996. In October 1996, FERC issued a procedural order, scheduling a hearing for April 28, 1997. The Company and all parties reached a settlement of issues raised in the proceeding, and on March 20, 1997, those parties jointly filed with FERC the Settlement Agreement and Motion to Certify the Settlement Agreement. On April 23, 1997 the presiding Administrative Law Judge certified the Settlement Agreement to the FERC and on June 11, 1997, the FERC approved the settlement.

In compliance with FERC's Order No. 889, on January 3, 1997, the Company filed its Procedures For Standards of Conduct for Unbundled Transmissions and Wholesale Merchant Function (Standards of Conduct) effective on that date. On July 1, 1997, the Company filed an amendment to the Standards of Conduct in Compliance with FERC's Order No. 889-A.

On July 16, 1997, the Company filed another amendment in response to a FERC Staff request. The Company is awaiting FERC action on the filing.

On September 11, 1997, FERC authorized the Company to sell power at market-based rates but set for hearing the issue of the impact of any transmission constraints on Virginia Power's ability to exercise generation market power in localized areas within its service territory. If FERC finds that transmission constraints give Virginia Power generation dominance, it could either revoke or limit the scope of the market-based rate authority. The hearing is scheduled to commence June 2, 1998.

On October 31, 1997, Virginia Power filed at FERC three agreements with Old Dominion Electric Cooperative (ODEC) to amend the parties' Interconnection and Operating Agreement (I&O Agreement) and to unbundle transmission services provided to ODEC under the I&O Agreement. On December 22, 1997, FERC issued a deficiency letter with respect to the filing directing the Company to provide additional information. On January 21, 1998, the Company provided the requested information. FERC accepted the agreements on March 12, 1998.

Virginia

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. Virginia Power filed its Alternative Regulatory Plan in March 1997, based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

In July 1996, Virginia Power proposed to substantially reduce the rates paid under Schedule 19 to cogenerators and small power producers of 100 kW or less. The rates became effective on an interim basis on January 1, 1997. On January 21, 1998, the Virginia Commission approved revised Schedule 19 rates. The approved rates do not differ in any significant way from the rates originally proposed by the Company.

In October 1996, Virginia Power filed an application with the Virginia Commission to increase its fuel factor from 1.299 cents per kWh to 1.322 cents per kWh, reflecting a fuel factor annual revenue increase of approximately $48.2 million. The increase became effective on an interim basis on December 1, 1996. On June 11, 1997, the Commission entered an Order Establishing Fuel Factor approving the requested increase.

On October 31, 1997, Virginia Power filed with the Virginia Commission its application for a reduction of $45.6 million in its fuel cost recovery factor for the period December 1, 1997 through November 30, 1998. The reduction became effective on an interim basis on December 1, 1997. Subsequently, as a result of amendments to two non-utility power purchase contracts, the Company proposed two additional reductions of approximately $30.2 million and $18 million for the same period, bringing the total proposed fuel factor reduction to $93.8 million. Both additional reductions were approved on an interim basis, effective March 1, 1998. A hearing is scheduled for April 9, 1998.

North Carolina

On November 4, 1996, the Company filed for approval of a new Schedule 19 which governs purchases from cogenerators and small power producers. The Company proposed rates substantially lower than those previously specified. It also proposed to reduce the applicability threshold to 100 kW and shorten the maximum term of contracts under Schedule 19 to five years. On June 19, 1997, the North Carolina Commission issued an Order requiring the Company to offer long-term (5-,10- and 15-year) levelized capacity payments to hydroelectric and certain landfill and waste facilities contracting for up to 5 MW; a 5-year levelized rate option to other QFs contracting for up to 100 kW; and optional long-term levelized energy payments for QFs rated at 100 kW or less capacity.

On October 10, 1997 the Company filed an application with the North Carolina Commission for a $728,000 increase in fuel revenues. On December 29, 1997, the North Carolina Commission entered an Order Approving Fuel Charge Adjustment. The Order approved an approximate $600,000 increase in the annual rates and charges paid by the retail customers of North Carolina Power effective on January 1, 1998.

CAPITAL REQUIREMENTS AND FINANCING PROGRAM

Construction and Nuclear Fuel Expenditures

Virginia Power's estimated construction and nuclear fuel expenditures for the three-year period 1998-2000, total $1.5 billion. It has adopted a 1998 budget for construction and nuclear fuel expenditures as set forth below:

	Estimated 1998 Expenditures (millions)
Production	$ 60
Technology	150
General Support Facilities	19
Transmission	37
Distribution	213
Nuclear Fuel	86
Total Construction Requirements and Nuclear Fuel Expenditures	$565

In addition, the Company expects to incur approximately $23 million of expenditures in 1998 in connection with the development of energy management projects for customers. Contracts with such customers provide for the recovery of these costs in future years.

Financing Program

The Company currently has three shelf registrations on file with the Securities Exchange Commission (SEC) providing the Company with $915 million of debt capital resources. The Company also has a Preferred Stock shelf registered with the SEC for $100 million in aggregate principal amount, which has not been utilized.

The Company intends to issue securities from time to time to meet its capital requirements, which include $333.5 million of long-term debt maturities in 1998.

Please see the Liquidity and Capital Resources section of MD&A for details about our Financing Program.

SOURCES OF POWER

Company Generating Units

Name of Station, Units and Location	Years Installed	Type of Fuel	Summer Capability MW
Nuclear:			
Surry Units 1 & 2, Surry, Va	1972-73	Nuclear	1,602
North Anna Units 1 & 2, Mineral, Va	1978-80	Nuclear	1,790(a)
Total nuclear stations			3,392
Fossil Fuel:			
Steam:			
Bremo Units 3 & 4, Bremo Bluff, Va.	1950-58	Coal	227
Chesterfield Units 3-6, Chester, Va.	1952-69	Coal	1,250
Clover Units 1 & 2, Clover, Va.	1995-96	Coal	882(b)
Mt. Storm Units 1-3, Mt. Storm, W. Va.	1965-73	Coal	1,587
Chesapeake Units 1-4, Chesapeake, Va.	1953-62	Coal	595
Possum Point Units 3 & 4, Dumfries, Va.	1955-62	Coal	322
Yorktown Units 1 & 2, Yorktown, Va.	1957-59	Coal	326
Possum Point Units 1, 2, & 5, Dumfries, Va.	1948-75	Oil	929
Yorktown Unit 3, Yorktown, Va.	1974	Oil & Gas	818
North Branch Unit 1, Bayard, W. Va.	1994	Waste Coal	74(c)
Combustion Turbines:			
35 units (8 locations)	1967-90	Oil & Gas	1,019
Combined Cycle:			
Bellmeade, Richmond, Va.	1991	Oil & Gas	230
Chesterfield Units 7 & 8, Chester, Va.	1990-92	Oil & Gas	397
Total fossil stations			8,656
Hydroelectric:			
Gaston Units 1-4, Roanoke Rapids, N.C.	1963	Conventional	225
Roanoke Rapids Units 1-4, Roanoke Rapids, N.C.	1955	Conventional	99
Other	1930-87	Conventional	3
Bath County Units 1-6, Warm Springs, Va.	1985	Pumped Storage	1,260(d)
Total hydro stations			1,587
Total Company generating unit capability			13,635
Net Purchases			1,480
Non-Utility Generation			3,277
Total Capability			18,392

(a) Includes an undivided interest of 11.6 percent (208 MW) owned by ODEC.

(b) Includes an undivided interest of 50 percent (441 MW) owned by ODEC.

(c) Effective January 25, 1996, this unit was placed in a cold reserve status.

(d) Reflects the Company's 60 percent undivided ownership interest in the 2,100 MW station. A 40 percent undivided interest in the facility is owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc (AE).

The Company's highest one-hour integrated service area summer peak demand was 14,537 MW on July 28, 1997, and an all-time high one-hour integrated winter peak demand of 14,910 MW was reached on February 5, 1996.

SOURCES OF ENERGY USED AND FUEL COSTS

For information as to energy supply mix and the average fuel cost of energy supply, see Results of Operations under MD&A.

Nuclear Operations and Fuel Supply

In 1997, the Company's four nuclear units achieved a combined capacity factor of 91.1 percent.

The Company utilizes both long-term contracts and spot purchases to support its needs for nuclear fuel. The Company continually evaluates worldwide market conditions in order to ensure a range of supply options at reasonable prices. Current agreements, inventories and spot market availability will support the Company's current and planned fuel supply needs for fuel cycles throughout the remainder of the 1990's and into the early 2000's. Beyond that period, additional fuel will be purchased as required to ensure optimum cost and inventory levels.

The DOE is not expected to begin the acceptance of spent fuel in 1998 as specified in the Company's contract with the DOE. However, on-site spent nuclear fuel storage at the Surry Power Station (spent fuel pool and dry cask storage) is expected to be adequate for the Company's needs until the DOE begins accepting spent fuel. The North Anna Power Station will require additional spent fuel storage capacity in 1998. The Company submitted a license application to the NRC in May 1995 for a dry cask facility at North Anna. The Company anticipates that this application will be approved in mid-1998.

For details on the issues of decommissioning and nuclear insurance, see Note C to the CONSOLIDATED FINANCIAL STATEMENTS.

Fossil Operations and Fuel Supply

The Company's fossil fuel mix consists of coal, oil and natural gas. In 1997, Virginia Power consumed approximately 13 million tons of coal. As with nuclear fuel, the Company utilizes both long-term contracts and spot purchases to support its needs. The Company presently anticipates that sufficient coal supplies at reasonable prices will be available for the remainder of the 1990's. Current projections for an adequate supply of oil remain favorable, barring unusual international events or extreme weather conditions which could affect both price and supply.

The Company uses natural gas as needed throughout the year for two combined cycle units and at several combustion turbine units. For winter usage at the combined cycle sites, gas is purchased and stored during the summer and fall and consumed during the colder months when gas supplies are not available at favorable prices. The Company has firm transportation contracts for the delivery of gas to the combined cycle units. Current projections indicate gas supplies will be available for the next several years.

Purchases and Sales of Energy

Virginia Power relies on purchases of power to meet a portion of its capacity requirements. The Company also makes economy purchases of power from other utility systems when it is available at a cost lower than the Company's own generation costs.

Under contracts effective January 1, 1985, Virginia Power agreed to purchase 400 MW of electricity annually through 1999 from Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier), and agreed to purchase 500 MW of electricity annually during 1987-99 from certain operating units of American Electric Power Company, Inc. (AEP).

The Company has a diversity exchange agreement with AE under which AE delivers 200 MW to Virginia Power in the summer and Virginia Power delivers 200 MW to AE in the winter.

Virginia Power also has 57 non-utility power purchase contracts with a combined dependable summer capacity of 3,277 MW (for information on the financial obligations under these agreements see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS). In a continuing effort to mitigate its exposure to above-market long-term purchased power contracts, the Company is evaluating its long-term purchased power contracts and negotiating modifications to their terms, including cancellations, where it is determined to be economically advantageous to do so.

The Company's wholesale power group actively participates in the purchase and sale of wholesale electric power and natural gas in the open market. The wholesale power group has expanded the Company's trading range beyond the geographic limits of the Virginia Power service territory, and has developed trading relationships with energy buyers and sellers on a nationwide basis.

In July 1997, the Company executed three agreements with Old Dominion Electric Cooperative (ODEC) which provide for the amendment of the parties' Interconnection and Operating Agreement (I&O Agreement). The first agreement provides for the transition from cost-based rates for capacity and energy purchases by ODEC to market-based rates by 2002. The second two agreements are the Service and Operating Agreements for Network Integration Transmission Service, which unbundled the transmission services provided to ODEC under the I&O Agreement.

FUTURE SOURCES OF POWER

As reported earlier, both the Hoosier 400 MW long-term purchase and the AEP 500 MW long-term purchase will expire on December 31, 1999. The Company presently anticipates adding peaking capacity beginning in the year 2000 to meet its anticipated load growth. The Company has and will pursue capacity acquisition plans to provide that capacity and maintain a high degree of service reliability. This capacity may be owned and operated by others and sold to the Company or may be built by the Company if it determines it can build capacity at a lower overall cost. The Company also pursues conservation and demand-side management (see CONSERVATION AND LOAD MANAGEMENT below). No Company-owned generation is currently in the planning or construction stages.

For additional information, see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS.

CONSERVATION AND LOAD MANAGEMENT

The Company is committed to evaluating and selecting demand-side and supply-side options on a consistent basis in order to provide reliable, low-cost service to its customers. Conservation and load management programs are evaluated annually at Virginia Power through a resource planning process that directly compares the stream of costs and benefits from supply-side and demand-side options. This process supports a conservation and load management portfolio which contributes both to the selection of low-cost resources to meet the future electricity needs of the Company's customers, as well as the efficient use of current resources.

Events in the evolving electric power marketplace and its regulatory and legislative environment continue to impact utility-sponsored conservation and load management programs. In the future, the Company anticipates a greater reliance on the use of price signals to convey information to our customers regarding energy-related costs, resulting in more efficient purchase decisions.

INTERCONNECTIONS

The Company maintains major interconnections with Carolina Power and Light Company, AEP, AE and the utilities in the Pennsylvania-New Jersey-Maryland Power Pool. Through this major transmission network, the Company has arrangements with these utilities for coordinated planning, operation, emergency assistance and exchanges of capacity and energy.

In December 1996, the Company joined with Allegheny Power Service Corporation, Cleveland Electric Illuminating Company, Toledo Edison Company, Ohio Edison Company, Pennsylvania Power Company and Southern Company Services, Inc. (the Transmission Alliance) to file a contract with the FERC entitled the GAPP Experiment Participation Agreement (GAPP Agreement). The Transmission Alliance and the GAPP Agreement were established to promote fair and equitable use of the transmission systems based on the General Agreement on Parallel Paths (GAPP) model for coordinating the flow of bulk supplies of electricity among utilities. GAPP principles allow electric companies to determine where electricity actually flows in bulk power transactions, as opposed to the "contract" paths that are based on power purchase and transmission agreements among buying, selling and transmitting utilities.

Compensation for transmission services has historically been based on contract paths. The GAPP Agreement was designed to determine the physical path electricity actually takes through the system and allocate open access transmission revenues among the parties. The GAPP Agreement was designed as an experiment to test the GAPP methods and procedures for a period of two years. The FERC accepted the contract on March 25, 1997. The Company and the Transmission Alliance implemented the GAPP Agreement on April 2, 1997.

On November 14, 1997, in accordance with the FERC order accepting the GAPP Agreement, the Transmission Alliance issued a report detailing the results of the first six months of the experiment. The preliminary results of the experiment indicate that it is technically possible to monitor and predict the physical flow of electricity over multiple systems and that transmission revenues reallocated according to actual use of the system differ significantly from collections under a contract path approach. In October 1997, Virginia Power gave notice to the Transmission Alliance that, effective January 1, 1998, it was exercising its option under the GAPP Agreement to terminate its involvement in the experiment.

On December 9, 1997, the Company, the Transmission Alliance and other utilities agreed to study the creation of an independent regional transmission entity. The memorandum of understanding to initiate this study was signed by eleven investor-owned electric companies, including Virginia Power, Consumers Energy, Detroit Edison, Duquesne Light Company, The Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, Toledo Edison Company, and the Allegheny Energy Companies (Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company). This group is an outgrowth of the GAPP Agreement and its key goals are to maintain the long-term reliability and security of the utilities' interconnected transmission systems; ensure the most efficient use of resources; eliminate pancaking of rates within and between transmission entities; avoid duplication of costs and achieve transmission cost savings; and, strike an appropriate balance among the diverse interests of energy suppliers, customers, and shareholders. The group will also explore cooperative agreements designed to achieve these goals while ensuring nondiscriminatory and comparable access to all users of the group's transmission system. The companies intend to be responsive to industry changes, especially with the introduction of retail competition in some of the areas served by the signatories and as some other industry participants consider creation of independent transmission operating companies or separate transmission companies. Further, the companies will have the flexibility to continue to investigate and pursue other opportunities and arrangements that could develop regarding independent system operators or independent transmission companies.

Virginia Power and Appalachian Power Company (AEP-Virginia), an operating unit of AEP, each sought approval from the SCC in 1991 to construct certain interconnecting transmission facilities. These applications resulted from a joint planning effort of Virginia Power and AEP to meet the requirements of their customers. At the time of Virginia Power's application, particularly during the summer of 1992, constraints were being experienced on transfers of power into the Virginia Power service territory from the west. On November 7, 1997, the SCC issued an Order directing the Company to report to the Commission on the continued need for certain new interconnected transmission facilities, on the relationship between the Company's application to build the new facilities and certain other pending proceedings, and on the Company's construction plans, if the SCC grants the Company's application.

On December 15, 1997, the Company filed a report in compliance with the SCC Order stating that since the filing of the Company's application, the constraints have been less frequent, due in part to less severe summer weather, and actual power requirements have been less than originally forecasted. In addition, generating resources within the Virginia Power service area have been increased by the higher performance level of the nuclear units, as well as the completion of the Clover Station. Completion of the AEP project is a prerequisite for the Virginia Power project to go forward. The proposed Virginia Power project would not fulfill its intended purpose without the AEP line being built. AEP has withdrawn its original application and has instituted a new proceeding before the Commission in which different routing is proposed. Virginia Power continues to monitor closely the progress of AEP in this proceeding with respect to its new proposal, but until more is known about these proceedings, Virginia Power cannot predict what its construction plans will be.

ITEM 2. PROPERTIES

The Company owns its principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of its property is subject to the lien of a mortgage securing its First and Refunding Mortgage Bonds. Right-of-way grants from the apparent owners of real estate have been obtained for most electric lines, but underlying titles have not been examined except for transmission lines of 69 Kv or more. Where rights of way have not been obtained, they could be acquired from private owners by condemnation if necessary. Many electric lines are on publicly owned property, as to which permission for use is generally revocable. Portions of the Company's transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, surplus capacity in the line if any exists.

The Company leases certain buildings and equipment. See Note G to the CONSOLIDATED FINANCIAL STATEMENTS.

See Company Generating Units under SOURCES OF POWER under Item 1. BUSINESS.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the Company is 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 the Company, or permits issued by various local, state and federal agencies for the construction or operation of facilities. From time to time, there may be administrative proceedings on these matters pending. In addition, in the normal course of business, the Company is involved in various legal proceedings. Management believes that the ultimate resolution of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

In December 1995, two civil actions were filed in the Virginia Circuit Court of the City of Norfolk against the City of Norfolk and Virginia Power, one for $15 million and one for $3 million, by property owners who each alleged contamination of their respective properties by hazardous substances originating on nearby property now owned by the city and formerly owned by the Company. In reference to the $15 million action, the parties reached a settlement prior to the scheduled August 18, 1997, trial date. The related action by the other property owner seeking $3 million is still pending, but has not yet been scheduled for trial.

On April 2, 1997, Doswell Limited Partnership (Doswell) filed a motion for judgment against Virginia Power in the Circuit Court of the City of Richmond. Doswell is an independent power producer that has entered into two power purchase agreements with Virginia Power and claims the Company breached one of those agreements. On the same date, Doswell also filed a complaint against Virginia Power in the United States District Court for the Eastern District of Virginia alleging certain claims relating to the two power purchase agreements. In March 1998, the parties agreed that both proceedings should be stayed in order to give the parties an opportunity to negotiate amendments to the power purchase agreements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On October 17, 1997, by Consent of the Sole Shareholder, Dominion Resources, Inc., the number of Virginia Power Directors was expanded to a maximum of eighteen (18) and the following Directors were elected to serve for terms expiring at the annual shareholder meetings for the years indicated below:

John B. Bernhardt	2000
John W. Harris	1998
Kenneth A. Randall	1999
Frank S. Royal	1998
Judith B. Sack	1999
S. Dallas Simmons	2000
David A. Wollard	1999

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All of the Company's Common Stock is owned by Dominion Resources.

The Company paid quarterly cash dividends on its Common Stock as follows:

	1st	2nd	3rd	4th
	(Millions)			
1997	$95.9	$93.4	$94.7	$95.9
1996	$95.3	$96.5	$96.1	$97.9

ITEM 6. SELECTED FINANCIAL DATA

	1997	1996	1995	1994	1993
	(Millions, except percentages)				
Revenues	$ 5,079.0	$ 4,420.9	$ 4,351.9	$ 4,170.8	$ 4,187.3
Income from operations	1,019.3	1,010.0	971.9	957.1	1,070.6
Net income	469.1	457.3	432.8	447.1	509.0
Balance available for Common Stock	433.4	421.8	388.7	404.9	466.9
Total assets	11,953.4	11,828.0	11,827.7	11,647.9	11,520.5
Total net utility plant	9,219.2	9,433.8	9,573.1	9,623.4	9,459.7
Long-term debt, noncurrent capital lease obligations, preferred stock subject to mandatory redemption and preferred securities of subsidiary trust	3,854.4	3,916.2	4,228.0	4,157.5	4,151.1
Utility plant expenditures (including nuclear fuel)	481.8	484.0	577.5	660.9	712.8
Capitalization ratios (percent):					
Debt	45.4	46.4	47.2	46.7	46.4
Preferred stock	7.6	7.5	7.5	9.0	9.2
Preferred securities	1.5	1.5	1.5		
Common equity	45.5	44.6	43.8	44.3	44.4
Embedded cost (percent):					
Long-term debt	7.60	7.68	7.73	7.65	7.67
Preferred stock	5.25	5.14	5.29	5.47	4.88
Preferred securities	8.72	8.72	8.72		
Weighted average	7.29	7.34	7.41	7.29	7.18

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995, including (without limitation) discussions as to expectations, beliefs, plans, objectives and future financial performance, or assumptions underlying or concerning matters discussed in this document. These discussions, and any other discussions, including certain contingency matters (and their respective cautionary statements) discussed elsewhere in this report, that are not historical facts, are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Some important factors that could cause actual results or outcomes to differ materially from those discussed in the forward-looking statements include current governmental policies and regulatory actions (including those of FERC, the EPA, the DOE, the NRC, the Virginia Commission and the North Carolina Commission), industry and rate structure, operation of nuclear power facilities, acquisition and disposal of assets and facilities, operation and storage facilities, recovery of the cost f purchased power, nuclear decommissioning costs, and present or prospective wholesale and retail competition. The business and profitability of Virginia Power also are influenced by economic and geographic factors including political and economic risks, changes in and compliance with environmental laws and policies, weather conditions and catastrophic weather-related damage, competition for retail and wholesale customers, pricing and transportation of commodities, market demand for energy, inflation, capital market conditions, unanticipated changes in operating expenses and capital expenditures, competition for new energy development opportunities and legal and administrative proceedings. All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond the control of Virginia Power. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of each such factor on the business of the Company.

Any forward-looking statement speaks only as of the date on which such statement is made, and Virginia Power undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Liquidity and Capital Resources

Operating activities continue to be a strong source of cash flow, providing $1,091 million in 1997 compared to $1,115 million in 1996. The decrease of $24 million (or 2 percent) from the previous year is attributable to normal business fluctuations. Over the past three years, cash flow from operating activities has, on average, covered 134 percent of our total construction requirements and provided 81 percent of our total cash requirements. Our remaining cash needs are met generally with proceeds from the sale of securities and short-term borrowings.

Financing activities have represented a net outflow of cash in recent years as strong cash flow from operations and the absence of major construction programs have reduced the Company's reliance on debt financing.

Cash from (used in) financing activities was as follows:

	1997	1996	1995
		(Millions)	
Issuance of long-term debt	$ 270.0	$ 24.5	$ 240.0
Issuance of preferred securities of subsidiary trust			135.0
Issuance (Repayment) of short-term debt	(86.2)	143.4	169.0
Repayment of long-term debt and preferred stock	(311.3)	(284.1)	(439.0)
Dividend payments	(415.6)	(421.4)	(438.6)
Other	(13.5)	(13.2)	(13.7)
Total	$(556.6)	$(550.8)	$(347.3)

We have taken advantage of declining interest rates by issuing new debt at lower rates as higher-rate debt has matured. For example, in 1997, $311.3 million of the Company's long-term debt securities matured with an average effective rate of 8.08 percent. As a partial replacement for this maturing debt, we issued $270 million of long-term debt securities during the year with an average effective rate of 6.84 percent.

We currently have three shelf registration statements effective with the Securities and Exchange Commission from which we can obtain additional debt capital: $400 million of Junior Subordinated Debentures; $375 million of Debt Securities, including First and Refunding Mortgage Bonds, Senior Notes and Senior Subordinated Notes filed in February 1998; and $200 million of Medium-Term Notes, Series F. The remaining principal amount of debt that can be issued under these registrations totals $915 million. An additional capital resource of $100 million in preferred stock also is registered with the Securities and Exchange Commission.

The Company has a commercial paper program that is supported by two credit facilities totaling $500 million. Proceeds from the sale of commercial paper are primarily used to provide working capital. Net borrowings under the program were $226.2 million at December 31, 1997.

Investing activities in 1997 resulted in a net cash outflow of $546.1 million, primarily due to $397.0 million of construction expenditures and $84.8 million of nuclear fuel expenditures. The construction expenditures included approximately $252.4 million for transmission and distribution projects, $52.1 million for production projects, $49.7 million for information technology projects and $42.8 million for other projects.

Cash used in investing activities was as follows:

	1997	1996	1995
		(Millions)	
Utility plant expenditures (excluding AFC — other funds)	$(397.0)	$(393.8)	$(519.9)
Nuclear fuel (excluding AFC — other funds)	(84.8)	(90.2)	(57.6)
Nuclear decommissioning contributions	(36.2)	(36.2)	(28.5)
Sale of accounts receivable, net			(160.0)
Purchase of assets	(19.8)	(13.7)	
Other	(8.3)	(12.5)	(11.1)
Total	$(546.1)	$(546.4)	$(777.1)

Capital Requirements

Capacity — The Company anticipates that kilowatt-hour sales will grow approximately 2.36 percent a year through 2000. We will continue to pursue capacity acquisition plans to meet the anticipated load growth and maintain a high degree of service reliability. The additional capacity may be purchased from others or built by the Company if we can build capacity at a lower overall cost. We have long-term purchase agreements with Hoosier (400 MW) and AEP (500 MW) which will expire on December 31, 1999. We presently anticipate adding peaking capacity beginning in the year 2000 to meet future load growth.

Fixed Assets — The Company's construction and nuclear fuel expenditures (excluding AFC), during 1998, 1999 and 2000 are expected to total $588.1 million, $476.2 million and $395.1 million, respectively. The Company presently estimates that all of its 1998 construction and nuclear fuel expenditures will be met through cash flow from operations.

Long-term Debt — The Company will require $333.5 million to meet maturities of long-term debt in 1998, which we expect to meet with cash flow from operations and issuance of replacement debt securities. Other capital requirements will be met through a combination of sales of securities and short-term borrowings.

Customer Service — The Company has adopted a plan to improve customer service, requiring an investment in excess of $100 million. Our plan includes:

- installing automated electric meters in metropolitan and inaccessible rural and urban locations,
- installing a new work management system,
- making technological changes to enhance the Company's ability to handle customer calls during power outages,
- installing mobile data dispatch technology in the Company's service fleet, accompanied by digitized mapping of our service territory, and
- initiating both local and regional distribution line improvement projects.

Expenditures in 1997 for these projects were approximately $23 million; future expenditures are expected to be approximately $68 million in 1998 and $15 million in 1999. We anticipate funding these projects with cash flow from operations.

Results of Operations

The following is a discussion of results of operations for the years ended 1997 as compared to 1996, and 1996 as compared to 1995.

1997 Compared to 1996

Revenue changed from the prior year primarily due to the following:

	1997	1996
	(Millions)	
Revenue — Electric Service		
Customer growth	$ 55.8	$ 45.1
Weather	(111.1)	4.4
Base rate variance	(18.7)	(35.5)
Fuel rate variance	44.1	(89.6)
Other retail, net	47.7	41.5
Total retail	17.8	(34.1)
Other electric service	11.0	(49.8)
Total electric service	28.8	(83.9)
Revenue — Other		
Wholesale — power marketing	363.4	96.6
Natural gas	232.6	33.2
Other, net	33.3	23.1
Total revenue — other	629.3	152.9
Total revenue	$ 658.1	$ 69.0

Electric service revenue consists of sales to retail customers in our service territory at rates authorized by the Virginia and North Carolina Commissions and sales to cooperatives and municipalities at wholesale rates authorized by FERC. The primary factors affecting this revenue in 1997 were customer growth, weather, and fuel rates.

Customer growth — There were 50,899 new customer connections to our system in 1997, the largest number of new connections in any year since 1990. This had the effect of increasing our sales by $55.8 million in 1997 over 1996.

Weather — The mild weather in 1997 caused customers to use less electricity for heating and cooling, which reduced revenue by approximately $111.1 million from the previous year. Heating and cooling degree days were as follows:

	1997	1996	Normal
Cooling degree days	1,349	1,365	1,530
Percentage change compared to prior year	(1.2)%	(18.1)%	
Heating degree days	3,787	4,131	3,726
Percentage change compared to prior year	(8.3)%	9.0%	

Fuel rates — The increase in fuel rate revenues is primarily attributable to higher fuel rates which went into effect December 1, 1996, increasing recovery of fuel costs by approximately $48.2 million. The regulatory commissions having jurisdiction over the Company allow us to charge customers for the cost of fuel used in generating electricity.

Other revenue includes sales of electricity beyond our service territory, natural gas, nuclear consulting services, energy management services and other revenue. The growth in power marketing and natural gas sales revenue is primarily due to our success at marketing electricity and natural gas beyond our service territory. The Company began pursuing these new lines of business in 1996. We expect that revenue from such non-traditional business activities will continue to grow in the near future.

Kilowatt-hour sales changed as follows:

	Increase (Decrease) From Prior Year	
	1997	1996
Residential	(1.8)%	2.3%
Commercial	0.6	2.3
Industrial	2.1	2.3
Public authorities	(4.7)	2.6
Total retail sales	(0.5)	2.4
Wholesale — system	2.5	(24.3)
Wholesale — power marketing	196.0	200.3
Total sales	17.2	6.3

The decrease in retail kilowatt-hour sales in 1997 as compared to 1996 reflects the impact of weather on our traditional electricity service business, despite continued customer growth. The increase in wholesale kilowatt-hour sales was primarily due to the Company's power marketing efforts.

Fuel, net increased as compared to 1996, primarily due to the cost of the power marketing and natural gas sales which reflects increased purchases of energy from other wholesale power suppliers and purchases of natural gas.

System energy output by energy source and the average fuel cost for each are shown below. Fuel cost is presented in mills (one tenth of one cent) per kilowatt hour.

	1997		1996		1995	
	Source	Cost	Source	Cost	Source	Cost
Nuclear (*)	34%	4.52	32%	4.48	32%	4.92
Coal (**)	40	13.54	38	14.32	39	14.44
Oil	1	26.32	1	27.75	1	25.11
Purchased power, net	23	21.54	27	21.99	25	22.50
Other	2	30.65	2	26.98	3	23.82
Total	100%		100%		100%	
Average fuel cost		12.67		13.47		13.73

(*) Excludes ODEC's 11.6 percent ownership interest in the North Anna Power Station.

(**) Excludes ODEC's 50 percent ownership interest in the Clover Power Station.

Other operations and maintenance increased as compared to 1996 as a result of costs associated with the growth in sales by the Company's energy services business unit. These higher costs were offset partially by a reduction in expenses attributable to the Company's strategic initiatives. Expenses in 1996 include high storm damage costs resulting from destructive summer storms, including Hurricane Fran.

Depreciation and amortization increased as compared to 1996 due to the recognition of additional depreciation and nuclear decommissioning expense to reflect adjustments in the Company's filing currently pending before the Virginia Commission and higher depreciation expense related to Clover Unit 2, which began operations in March 1996. See Future Issues — *Utility Rate Regulation* for additional information on current rate proceedings.

Restructuring expenses decreased as compared to 1996 as the Company nears completion of its Vision 2000 strategic initiative. Charges for restructuring primarily include employee severance costs, costs to restructure agreements to purchase power from third parties and, when necessary, to negotiate settlement and termination of these contracts, and other costs. The Company estimates that staffing reductions will result in annual savings, in the range of $80 million to $90 million. However, these savings are being offset by salary increases, outsourcing costs and increased payroll costs associated with staffing for growth opportunities. See also Note O to the CONSOLIDATED FINANCIAL STATEMENTS.

Accelerated cost recovery represents a reserve for potential adjustments to regulatory assets. In this increasingly competitive environment, the Company has concluded that it is appropriate to utilize available cost reductions, such as those generated by the Vision 2000 program, to accelerate the write-off of unamortized regulatory assets and potentially stranded costs (see Future Issues — *Competition*).

1996 Compared to 1995

Electric service revenues decreased as compared to 1995 due to the effect of mild weather on the Company's summer retail rates, which are designed to reflect normal weather conditions. These revenues also were affected by reduced sales to Old Dominion Electric Cooperative (ODEC) due to the completion of Clover Units 1 and 2, of which ODEC owns a fifty percent interest.

Other revenues increased as compared to 1995 due to growth in our power marketing and energy services business, which was organized as a distinct business unit in 1996.

Fuel, net increased as compared to 1995, primarily as a result of increased energy purchases associated with our power marketing sales, offset in part by a higher recovery of fuel expenses subject to deferral accounting in 1995.

Operations and maintenance decreased slightly as compared to 1995, primarily as a result of a reduction in expenses attributable to the Company's strategic initiatives, offset partly by the high storm damage costs incurred in 1996 from destructive summer storms, including Hurricane Fran.

Depreciation and amortization increased as compared to 1995, primarily as a result of greater nuclear decommissioning expense and depreciation related to Clover Units 1 and 2, which were placed in service in October 1995 and March 1996, respectively.

Restructuring decreased as compared to 1995 as the implementation phase of the Vision 2000 initiative continued. Restructuring charges in 1996 included severance costs, costs to restructure or settle certain contracts to purchase power and other costs. In addition, 1995 restructuring costs included one-time charges to cancel specific capital projects and adjustments to inventory and certain real estate to reflect adoption of changes in business strategies and processes.

Accelerated cost recovery represents a provision for management's estimate of a reserve that may ultimately be used to accelerate the write-off of unamortized regulatory assets and potentially stranded costs (see Future Issues — *Competition*).

Future Issues

Competition in the Electric Industry — General

For most of this century, the structure of the electric industry in Virginia and throughout the United States has been relatively stable. We have recently seen, however, federal and state developments toward increased competition. Electric utilities have been required to open up their transmission systems for use by potential wholesale competitors. In addition, non-utility power producers now compete with electric utilities in the wholesale generation market. At the federal level, retail competition is under consideration. Some states have enacted legislation requiring retail competition.

Today, Virginia Power faces competition in the wholesale market. Currently, there is no general retail competition in Virginia Power's principal service area. To the extent that competition is permitted, Virginia Power's ability to sell power at prices that allow it to recover its prudently incurred costs may be an issue. See Future Issues — *Competition — Exposure to Potentially Stranded Costs.*

In response to competition, Virginia Power has successfully renegotiated long term contracts with wholesale and large federal government customers. In addition, the Company has obtained regulatory approval of innovative pricing proposals for large industrial customers. Rate concessions resulting from these contract negotiations and innovative pricing proposals are expected to reduce the Company's 1998 revenue by approximately $40 million. To date, the Company has not experienced any material loss of load.

Virginia Power is actively participating in the legislative and regulatory processes relating to industry restructuring. The Company has also responded to these trends toward competition by cutting its costs, re-engineering its core business processes, and pursuing innovative approaches to serving traditional markets and future markets. In addition, a significant part of the Company's strategy relies on developing "non-traditional" businesses within the Company's business units and subsidiaries designed to provide growth in future earnings, including:

- Energy Services — offering electric energy and capacity in the emerging wholesale market as well as natural gas, and other energy related products and services;
- Fossil & Hydro — targeting process type industries, such as chemical, paper, plastics and petroleum to become a service provider of instrumentation equipment;
- Nuclear Services — offering management and operations services to other electric utilities;

- Commercial Operations — providing power distribution related services, including transmission and distribution, engineering and metering services to other gas, water and electric utilities; and
- Telecommunications — offering telecommunications services through the Company's existing fiber-optic network.

The Company's non-traditional businesses face competition from a variety of utility and non-utility entities. In addition, Virginia Power may from time to time identify and investigate opportunities to expand its markets through strategic alliances with partners whose strengths, market position and strategies complement those of the Company.

Competition — Wholesale

During 1997, sales to wholesale customers represented approximately 17 percent of the Company's total revenues from electric sales. Approximately 73 percent of wholesale revenues resulted from the Company's power marketing efforts.

In July 1997, Virginia Power filed amendments to its existing rate tariffs with FERC so it could make wholesale sales at market-based rates. Under a FERC order conditionally accepting the Company rates for filing, Virginia Power began making market-based sales in 1997. FERC set for hearing in June 1998 the issue of whether transmission constraints limiting the transfer of power into the Company's service territory provide Virginia Power with generation dominance in localized markets. If FERC finds transmission constraints give Virginia Power generation dominance, it could revoke or limit the scope of the Company's market-based rate authority.

Virginia Power has successfully negotiated a new power supply arrangement with its largest wholesale customer. The new arrangement provides for a transition from cost-based rates to market-based rates, subject to FERC approval. Virginia Power estimates the reduced rates, offset in part by other revenues which may be earned under the agreement, will decrease income before taxes by approximately $38 million through 2005. Virginia Power anticipates that additional contract negotiations with other wholesale customers will take place in the future.

Competition — Retail

Currently, Virginia Power has the exclusive right to provide electricity at retail within its assigned service territories in Virginia and North Carolina. As a result, Virginia Power now only faces competition for retail sales if certain of its business customers move into another utility service territory, use other energy sources instead of electric power, or generate their own electricity. However, both Virginia and North Carolina are considering implementing retail competition.

Competition — Legislative Initiatives

Virginia: In the 1998 Session, the Virginia General Assembly passed House Bill No. 1172 (HB1172) to establish a schedule for Virginia's transition to retail competition in the electric utility industry. The Company actively supported HB1172, which passed both houses of the General Assembly in amended form and now awaits action by the Governor. HB1172 requires the following:

- establishment of one or more independent system operators (ISO) and one or more regional power exchanges (RPX) for Virginia by January 1, 2001;
- deregulation of generating facilities beginning January 1, 2002;
- transition to retail competition to begin on January 1, 2002, with retail competition to begin on January 1, 2004;
- recovery of just and reasonable net stranded costs; and
- appropriate consumer safeguards related to stranded costs and consideration of stranded benefits.

If HB1172 becomes law, it will become effective July 1, 1998. While the bill establishes a timeline for the transition to competition in Virginia, a detailed plan to implement that transition must be developed through future legislative and regulatory action. The Company is unable at this time to predict its timing or details.

Federal: The U.S. Congress is expected to consider federal legislation in the near future authorizing or requiring retail competition. Virginia Power cannot predict what, if any, definitive actions the Congress may take.

North Carolina: The 1997 Session of the North Carolina General Assembly created a Study Commission on the Future of Electric Service in North Carolina. An interim report is expected in 1998 with final recommendations made to the 1999 session of the North Carolina General Assembly.

Competition — Regulatory Initiatives

The Virginia Commission also has been actively interested in industry restructuring and competition, as shown in the following generic and utility-specific proceedings.

In 1995, the Commission instituted an ongoing generic investigation on restructuring, resulting in a number of reports by its Staff covering such issues as retail wheeling experiments and the status of wholesale power markets.

In November 1996, the Commission ordered Virginia Power to file studies and reports on possible restructuring of the electric industry in Virginia. The Commission also invited Virginia Power to submit a proposed alternative regulation plan with its filing. A two-phase alternative regulatory plan (ARP) was filed March 1997. During Phase I (1997 to December 2002), Virginia Power proposed implementing a freeze of its current base rates and devoting a portion of earnings above a 11.5% return-on-equity to accelerate the write-off of generation-related regulatory assets and to mitigate the costs associated with payments under power purchase contracts with non-utility generators that may be above market if competition is authorized in Virginia. During Phase II (beyond December 31, 2002), Virginia Power would seek Commission approval of stranded cost recovery if retail competition is implemented in Virginia and a transition cost charge mechanism by which stranded costs would be recovered. Virginia Power presented illustrative estimates of stranded costs based on hypothetical market prices as part of its Phase II filing. When the Company filed its ARP, the Commission consolidated its consideration of the ARP with its consideration of the Company's 1995 Annual Information Filing. For a discussion of the 1995 Annual Information Filing, See Future Issues — *Utility Rate Regulation.*

In November 1997, the Commission Staff issued its report to the General Assembly calling for a cautious, two-phase, five-year period to address restructuring issues. The report acknowledged the need for direction from the Virginia legislature concerning policy issues surrounding competition in the electric industry. Virginia Power sought to withdraw its ARP in December 1997, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP, but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing (See Future Issues — *Utility Rate Regulation).*

Competition — SFAS 71

Virginia Power's regulated rates are designed to recover its prudently incurred costs of providing service, including the opportunity to earn a reasonable return on its shareholder's investment. The Company's financial statements reflect assets and costs under this cost-based rate regulation in accordance with Statement of Financial Accounting Standards No. 71 (SFAS 71), "Accounting for the Effects of Certain Types of Regulation." SFAS 71 provides that certain expenses normally reflected in income are deferred on the balance sheet as regulatory assets and are recognized as the related amounts are included in rates and recovered from customers. Continued accounting under SFAS 71 requires that rates designed to recover the utility's specific costs of providing service, are, and will continue to be, established by regulators. The presence of increasing competition that limits the utility's ability to charge rates that recover its costs, or a change in the method of regulation with the same effect, could result in the discontinued applicability of SFAS 71.

Rate-regulated companies are required to write off regulatory assets against earnings whenever those assets no longer meet the criteria for recognition as defined by SFAS 71. In addition, SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," requires a review of long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Thus, events or changes in circumstances that cause the discontinuance of SFAS 71, and write off of regulatory assets, may also require a review of utility plant assets for possible impairment. If such review indicates utility plant assets are impaired, the carrying amount of the affected assets would be written down. This would result in a loss being charged to earnings, unless recovery of the loss is provided through operations that remain regulated.

Virginia Power's regulated operations currently satisfy the SFAS 71 criteria. However, if events or circumstances should change so that those criteria are no longer satisfied, management believes that a material adverse effect on the Company's results of operations and financial position may result. The form of cost-based rate regulation under which Virginia Power operates is likely to evolve as a result of various legislative or regulatory initiatives. At this time, management can predict neither the ultimate outcome of regulatory reform in the electric utility industry nor the impact such changes would have on Virginia Power.

Competition — Exposure to Potentially Stranded Costs

Under traditional cost-based regulation, utilities have generally had an obligation to serve supported by an implicit promise of the opportunity to recover prudently incurred costs. The most significant potential adverse effect of competition is "stranded costs." Stranded costs are those costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market.

The Company's potential exposure to stranded costs is comprised of the following:

- long-term purchased power contracts that may be above market (see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS);
- costs pertaining to certain generating plants that may become uneconomic in a deregulated environment;
- regulatory assets for items such as income tax benefits previously flowed-through to customers, deferred losses on reacquired debt and other costs; (see Note F to the CONSOLIDATED FINANCIAL STATEMENTS); and
- unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements (see Notes C and N to the CONSOLIDATED FINANCIAL STATEMENTS).

Any forecast of potentially stranded costs is extremely sensitive to the various assumptions made. Such assumptions include:

- the timing and extent of customer choice in the market for electric service;
- estimates of future competitive market prices;
- sales and load growth forecasts;
- power stations' future operating performance;
- rate revenues permitted during the transition;
- estimated costs of utility operations over time;
- mitigation opportunities;
- stranded cost recovery mechanisms and other factors.

Certain combinations of these assumptions as applied to Virginia Power would produce little to no stranded costs; under other scenarios Virginia Power's exposure to potentially stranded costs could be substantial.

Virginia Power has assessed the reasonableness of various possible assumptions, but has not been able to settle on any particular combination thereof. Thus, the Company's maximum exposure to potentially stranded costs is uncertain. Management believes that recovery of any potentially stranded costs is appropriate and will vigorously pursue such recovery with the regulatory commissions having jurisdiction over its operations. However, Virginia Power cannot predict the extent to which such costs, if any, will be recoverable from customers. Also, in an effort to mitigate the amount at risk, the Company will continue to implement cost reduction measures.

Utility Rate Regulation

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. Virginia Power filed its ARP in March 1997, based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

Utility Operations

The Company strives to operate its generating facilities in accordance with prudent utility industry practices and in conformity with applicable statutes, rules and regulations. Like other electric utilities, the Company's generating facilities are subject to unanticipated or extended outages for repairs, replacements or modification of equipment or otherwise to comply with regulatory requirements. Such outages may involve significant expenditures not previously budgeted, including replacement energy costs.

On September 10, 1997, the NRC published a proposed rule for financial assurance requirements related to nuclear decommissioning. If the NRC's proposed rule were implemented without further clarification or modification, the Company may have to either pre-fund or provide acceptable security for a portion of its nuclear decommissioning obligation. See Note C to the CONSOLIDATED FINANCIAL STATEMENTS.

Environmental Matters

The Company is subject to rising costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations of the Company. These costs have been historically recovered from customers through utility rates. However, to the extent that the regulatory environment departs from cost-based rates, the Company's results of operations and financial condition could be adversely impacted.

Environmental Protection and Monitoring Expenditures

The Company incurred $70.4 million, $71.1 million and $68.3 million (including depreciation) during 1997, 1996 and 1995, respectively, in connection with the use of environmental protection facilities and expects these expenses to be approximately $69.1 million in 1998. In addition, capital expenditures to limit or monitor hazardous substances were $24.6 million, $22.4 million and $23.4 million for 1997, 1996 and 1995, respectively. The amount estimated for 1998 for these expenditures is $10.0 million.

Clean Air Act Compliance

The Clean Air Act, as amended in 1990, requires the Company to reduce its emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The Clean Air Act also requires the Company to obtain operating permits for all major emissions-emitting facilities. Permit applications have been submitted for the Company's power stations located in North Carolina and West Virginia. Applications for the Company's power stations located in Virginia will be filed in 1998.

The Clean Air Act's SO_2 reduction program is based on the issuance of a limited number of SO_2 emission allowances, each of which may be used as a permit to emit one ton of SO_2 into the atmosphere or may be sold to someone else. The program is administered by the EPA. The Company's compliance plans may include switching to lower sulfur coal, purchase of emission allowances and installation of SO_2 control equipment. Maximum flexibility and least-cost compliance will be maintained through annual studies.

The Company began complying with Clean Air Act Phase I NO_x limits at eight of its units in Virginia in 1997, three years earlier than otherwise required. As a result, the units will not be subject to more stringent Phase II limits until 2008. Furthermore, in order to avoid the necessity of more stringent regulations, the Company made voluntary commitments in 1996 to cap NO_x emissions at its Chesterfield and Yorktown Power Stations and the Chesapeake Energy Center during the ozone season beginning in 2000.

From 1994 through 1997, the Company invested more than $160 million to install and upgrade SO_2 and NO_x emission control equipment at its Mt. Storm and Possum Point power stations. Capital expenditures related to Clean Air Act compliance over the next five years are projected to be approximately $40 million. Changes in the regulatory environment, availability of allowances, and emissions control technology could substantially impact the timing and magnitude of compliance expenditures.

In November 1997, the EPA proposed new requirements for 22 states, including North Carolina, Virginia and West Virginia, to reduce and cap emissions of NO_x. The EPA will issue a final rule by September 1998. Although the proposal allows each state to determine how to achieve the required reduction in emissions, the caps were calculated based on emission limits for utility boilers. If the states in which Virginia Power operates choose to impose this limit, major additional emission control equipment, with attendant significant capital and operating costs, could be required.

Global Climate Change

In 1993, the United Nation's Global Warming Treaty became effective. The objective of the treaty is the stabilization of greenhouse gas concentrations at a level that would prevent man-made emissions from interfering with the climate system.

As a continuation of the effort to limit man-made greenhouse emissions, an international Protocol was formulated on December 10, 1997, in Kyoto, Japan. This Protocol calls for the United States to reduce greenhouse emissions by 7 percent from 1990 baseline levels by the period 2008-2012. The Protocol will not constitute a binding commitment unless submitted to and approved by the United States Senate. Emission reductions of the magnitude included in the Protocol, if adopted, would likely result in a substantial financial impact on companies that consume or produce fossil fuel-derived electric power, including Virginia Power.

Recently Issued Accounting Standards

During 1997, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 130, "Reporting Comprehensive Income," and SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Each of these statements is effective for fiscal years beginning after December 15, 1997. At this time, the Company does not expect the implementation of these standards to have a material impact on its results of operations or financial position.

Year 2000 Compliance

Virginia Power is taking an aggressive approach regarding computer issues associated with the onset of the new millenium — specifically, the impact of the possible failure of computer systems and computer-driven equipment due to the rollover to the year 2000. The year 2000 problem is pervasive and complex as virtually every computer operation could be affected in some way by the rollover of the two-digit year value from 99 to 00. The issue is whether computer systems will properly recognize date-sensitive information when the year changes to 2000. Systems that do not properly recognize such information could generate erroneous data or fail.

If not properly addressed, the year 2000 computer problem could result in failures in computer systems in the Company and the computer systems of third parties with which the Company transacts business. Such failures of the Company's or third parties' computer systems could have a material impact on the Company's ability to conduct business.

Since January 1997, the Company has organized a formal year 2000 project team to identify, correct or reprogram and test its systems for year 2000 compliance. At this time, the project team has completed its preliminary assessment. Based on the team's evaluation, the costs of testing and conversion of system applications are projected to be within the range of $30 million to $50 million. The range is a function of our ongoing evaluation as to whether certain systems and equipment will be corrected or replaced, which is dependent on information yet to be obtained from suppliers and other external sources. Maintenance or modification costs will be expensed as incurred, while the costs of new software and hardware will be capitalized and amortized over the asset's useful life.

At this time, Virginia Power is actively pursuing solutions to its year 2000-related computer problems in order to ensure that foreseeable situations related to Company computer systems are effectively addressed. The Company cannot estimate or predict the potential adverse consequences, if any, that could result from a third party's failure to effectively address this issue.

Market Rate Sensitive Instruments and Risk Management

Virginia Power is subject to market risk as a result of its use of various financial instruments and derivative commodity instruments. Interest rate risk generally is associated with the Company's outstanding debt, preferred stock and trust-issued securities. The Company also is exposed to interest rate risk as well as equity price risk as a result of its nuclear decommissioning trust investments in debt and equity securities.

The Company's wholesale power group is involved in trading activities which use derivative commodity instruments. However, the fair value of such instruments at December 31, 1997, is not material to the Company's financial position. Also, the potential near term losses in future earnings, fair values, or cash flows, resulting from reasonably possible near term changes in market prices for such instruments are not anticipated to be material to the Company's results of operations, financial position or cash flows.

The following analysis does not include the price risks associated with the nonfinancial assets and liabilities of utility operations, including underlying fuel requirements.

Interest-rate risk

Virginia Power uses both fixed rate and variable rate debt and preferred securities as sources of capital. The following table presents the financial instruments that are held or issued by the Company at December 31, 1997, and are sensitive to interest rate changes in some way. Weighted average variable rates are based on implied forward rates derived from appropriate annual spot rate observations as of December 31, 1997.

	Expected Maturity Date							
	1998	1999	2000	2001	2002	Thereafter	Total	Fair Value
	(Millions of Dollars, Except Percentages)							
ASSETS								
Nuclear decommissioning trust investments	$ 17.7	$ 5.3	$ 2.1	$ 7.1	$ 3.1	$ 165.0	$ 200.3	$ 190.7
Average interest rate (1)	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%		
LIABILITIES — Fixed rate								
Mortgage bonds	225.0	100.0	135.0	100.0	255.0	2,009.5	2,824.5	2,937.7
Average interest rate	6.7%	8.9%	5.9%	6.0%	4.5%	7.6%		
Medium term notes	108.5	221.0	60.5	60.6	60.0	40.5	551.1	573.7
Average interest rate	7.6%	8.5%	9.7%	8.4%	7.6%	9.0%		
Tax-exempt financing						10.0	10.0	10.4
Average interest rate						5.2%		
Short-term debt	226.2						226.2	226.2
Average interest rate	5.9%							
Preferred stock, subject to mandatory redemption			180.0				180.0	186.6
Average dividend rate			6.2%					
Mandatorily redeemable trust-issued preferred securities						135.0	135.0	137.7
Average dividend rate						8.1%		
LIABILITIES — Variable rate								
Tax-exempt financing (2)						488.6	488.6	488.6
Average interest rate						4.1%		

(1) Rates are based on average yield for entire portfolio at December 31, 1997.

(2) Interest rates on the tax-exempt bonds are based on short-term, tax-exempt market rates and are reset for periods of one to 270 days in length. The Company has the option to convert these bonds to fixed rate securities upon 40 days written notice. See Note H to the CONSOLIDATED FINANCIAL STATEMENTS.

Equity price risk

The following table presents a description of marketable equity securities held by the Company at December 31, 1997. As prescribed by Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities," these securities are reported on the balance sheet at fair value.

	Cost	Fair Value
	(Millions of Dollars)	
Nuclear decommissioning trust investments	$ 219.4	$ 360.4

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX

REPORT OF MANAGEMENT

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

Management maintains a system of internal accounting controls designed to provide reasonable assurance, at a reasonable cost, that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. Management recognizes the inherent limitations of any system of internal accounting control and, therefore, cannot provide absolute assurance that the objectives of the established internal accounting controls will be met. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits. Management believes that during 1997 the system of internal control was adequate to accomplish the intended objective.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, independent auditors, who have been engaged by the Board of Directors. Their audits were conducted in accordance with generally accepted auditing standards and included a review of the Company's accounting systems, procedures and internal controls, and the performance of tests and other auditing procedures sufficient to provide reasonable assurance that the Consolidated Financial Statements are not materially misleading and do not contain material errors.

The Audit Committee of the Board of Directors, composed entirely of directors who are not officers or employees of the Company, meets periodically with the independent auditors, the internal auditors and management to discuss auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

Management recognizes its responsibility for fostering a strong ethical climate so that the Company's affairs are conducted according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in the Company's Code of Ethics, which is distributed throughout the Company. The Code of Ethics addresses, among other things, the importance of ensuring open communication within the Company; potential conflicts of interest; compliance with all domestic and foreign laws, including those relating to financial disclosure; the confidentiality of proprietary information; and full disclosure of public information.

VIRGINIA ELECTRIC AND POWER COMPANY

Norman Askew President and Chief Executive Officer	M. S. Bolton, Jr. Controller and Principal Accounting Officer

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors of Virginia Electric and Power Company:

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly owned subsidiary of Dominion Resources, Inc.) and subsidiaries (the Company) as of December 31, 1997 and 1996, and the related consolidated statements of income, earnings reinvested in business, and cash flows for each of the three years in the period ended December 31, 1997. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles.

DELOITTE & TOUCHE LLP

Richmond, Virginia
February 9, 1998

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1997	1996	1995
		(Millions)	
Revenues:			
Electric service	$4,239.0	$4,210.2	$4,294.1
Other	840.0	210.7	57.8
Total	5,079.0	4,420.9	4,351.9
Expenses:			
Fuel, net	1,620.7	1,016.6	1,009.7
Purchased power capacity, net	717.5	700.6	688.4
Operations and maintenance	812.7	803.1	805.6
Depreciation and amortization	549.9	502.0	469.1
Restructuring	18.4	64.9	117.9
Accelerated cost recovery	38.4	26.7	
Amortization of terminated construction project costs	34.4	34.4	34.4
Taxes other than income	267.7	262.6	254.9
Total	4,059.7	3,410.9	3,380.0
Income from operations	1,019.3	1,010.0	971.9
Other income	14.2	6.8	10.0
Income before interest and income taxes	1,033.5	1,016.8	981.9
Interest and related charges:			
Interest expense, net	304.2	308.4	317.9
Distributions — preferred securities of subsidiary trust	10.9	10.9	3.7
Total	315.1	319.3	321.6
Income before income taxes	718.4	697.5	660.3
Income taxes	249.3	240.2	227.5
Net income	469.1	457.3	432.8
Preferred dividends	35.7	35.5	44.1
Balance available for Common Stock	$ 433.4	$ 421.8	$ 388.7

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS

Assets

(Millions of Dollars)	At December 31, 1997	1996
CURRENT ASSETS:		
Cash and cash equivalents	$ 36.0	$ 47.9
Accounts receivable:		
Customers (less allowance for doubtful accounts of $2.4 in 1997 and 1996)	462.4	354.8
Other	108.0	80.4
Accrued unbilled revenues	245.2	180.3
Materials and supplies at average cost or less:		
Plant and general	145.2	148.7
Fossil fuel	67.4	76.8
Other	134.7	107.0
Total current assets	1,198.9	995.9
INVESTMENTS:		
Nuclear decommissioning trust funds	569.1	443.3
Other	38.3	34.5
Total net investments	607.4	477.8
DEFERRED DEBITS AND OTHER ASSETS:		
Regulatory assets:		
Deferred capacity expenses	47.3	6.1
Other	729.3	767.8
Unamortized debt issuance costs	24.2	24.7
Other	127.1	121.9
Total deferred debits and other assets	927.9	920.5
UTILITY PLANT:		
Plant (includes plant under construction of $240.9 in 1997 and $180.1 in 1996)	14,794.2	14,506.8
Less accumulated depreciation	5,724.3	5,218.3
	9,069.9	9,288.5
Nuclear fuel (less accumulated amortization of $705.0 in 1997 and $698.5 in 1996)	149.3	145.3
Total net utility plant	9,219.2	9,433.8
Total assets	$11,953.4	$11,828.0

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS

Liabilities and Shareholders' Equity

(Millions of Dollars)	At December 31, 1997	At December 31, 1996
CURRENT LIABILITIES:		
Securities due within one year	$ 333.5	$ 311.3
Short-term debt	226.2	312.4
Accounts payable, trade	452.0	368.5
Customer deposits	44.6	50.0
Payrolls accrued	77.5	73.2
Severance costs accrued	29.7	50.2
Interest accrued	95.1	95.3
Other	161.6	126.1
Total current liabilities	1,420.2	1,387.0
LONG-TERM DEBT	3,514.6	3,579.4
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	1,607.0	1,565.2
Deferred investment tax credits	238.4	255.3
Deferred fuel expenses	12.8	3.3
Other	220.3	151.1
Total deferred credits and other liabilities	2,078.5	1,974.9
COMMITMENTS AND CONTINGENCIES (See Note Q)		
COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST*	135.0	135.0
PREFERRED STOCK:		
Preferred stock subject to mandatory redemption	180.0	180.0
Preferred stock not subject to mandatory redemption	509.0	509.0
COMMON STOCKHOLDER'S EQUITY:		
Common Stock, no par, 300,000 shares authorized, 171,484 shares outstanding at December 31, 1997 and 1996	2,737.4	2,737.4
Other paid-in capital	16.9	16.9
Earnings reinvested in business	1,361.8	1,308.4
Total common stockholder's equity	4,116.1	4,062.7
Total liabilities and shareholders' equity	$11,953.4	$11,828.0

(*) As described in Note I to CONSOLIDATED FINANCIAL STATEMENTS, the 8.05% Junior Subordinated Notes totalling $139.2 million principal amount constitute 100% of the Trust's assets.

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF EARNINGS REINVESTED IN BUSINESS

	For the Years Ended December 31,		
	1997	1996	1995
		(Millions)	
Balance at beginning of year	$1,308.4	$1,272.5	$1,277.8
Net income	469.1	457.3	432.8
Total	1,777.5	1,729.8	1,710.6
Cash dividends:			
Preferred stock subject to mandatory redemption	11.1	11.1	13.5
Preferred stock not subject to mandatory redemption	24.7	24.5	30.8
Common Stock	379.9	385.8	394.3
Total dividends	415.7	421.4	438.6
Other additions (deductions), net			0.5
Balance at end of year	$1,361.8	$1,308.4	$1,272.5

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 1997	1996	1995
	(Millions)		
Cash Flow From Operating Activities:			
Net income	$ 469.1	$ 457.3	$ 432.8
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	664.7	616.0	585.1
Deferred income taxes	36.1	69.1	11.8
Deferred investment tax credits	(16.9)	(16.9)	(16.9)
Noncash return on terminated construction project costs — pretax	(4.2)	(6.4)	(8.4)
Deferred fuel expenses, net	9.6	(54.4)	6.2
Deferred capacity expenses	(41.2)	(9.2)	6.4
Restructuring	12.5	29.6	96.2
Accelerated cost recovery	38.4	26.7	
Changes in:			
Accounts receivable	(135.2)	(11.3)	(54.3)
Accrued unbilled revenues	(64.9)	17.6	(27.7)
Materials and supplies	12.9	6.0	61.1
Accounts payable, trade	82.8	57.8	(8.9)
Accrued expenses	(13.9)	(62.6)	44.7
Other	41.0	(4.0)	(2.7)
Net Cash Flow From Operating Activities	1,090.8	1,115.3	1,125.4
Cash Flow From (To) Financing Activities:			
Issuance of long-term debt	270.0	24.5	240.0
Issuance of preferred securities of subsidiary trust			135.0
Issuance (Repayment) of short-term debt	(86.2)	143.4	169.0
Repayment of long-term debt and preferred stock	(311.3)	(284.1)	(439.0)
Common Stock dividend payments	(379.9)	(385.8)	(394.3)
Preferred stock dividend payments	(35.7)	(35.6)	(44.3)
Distribution-preferred securities of subsidiary trust	(10.9)	(10.9)	(3.7)
Other	(2.6)	(2.3)	(10.0)
Net Cash Flow To Financing Activities	(556.6)	(550.8)	(347.3)
Cash Flow Used In Investing Activities:			
Utility plant expenditures (excluding AFC — other funds)	(397.0)	(393.8)	(519.9)
Nuclear fuel (excluding AFC — other funds)	(84.8)	(90.2)	(57.6)
Nuclear decommissioning contributions	(36.2)	(36.2)	(28.5)
Sale of accounts receivable, net			(160.0)
Purchase of assets	(19.8)	(13.7)	
Other	(8.3)	(12.5)	(11.1)
Net Cash Flow Used In Investing Activities	(546.1)	(546.4)	(777.1)
Increase in cash and cash equivalents	(11.9)	18.1	1.0
Cash and cash equivalents at beginning of year	47.9	29.8	28.8
Cash and cash equivalents at end of year	$ 36.0	$ 47.9	$ 29.8
Cash paid during the year for:			
Interest (reduced for the cost of borrowed funds capitalized as AFC)	$ 277.1	$ 295.4	$ 314.5
Income taxes	230.0	216.1	215.8

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Significant Accounting Policies:

General

Virginia Electric and Power Company is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy within a 30,000 square-mile area in Virginia and northeastern North Carolina. It sells electricity to retail customers (including governmental agencies) and to wholesale customers such as rural electric cooperatives, municipalities, power marketers and other utilities. The Virginia service area comprises about 65 percent of Virginia's total land area, but accounts for over 80 percent of its population. The Company has organized a wholesale power group to engage in off-system wholesale purchases and sales of electricity and purchases and sales of natural gas, and that group is developing trading relationships beyond the geographic limits of Virginia Power's retail service territory. Within this document, the terms "Virginia Power" and the "Company" shall refer to the entirety of Virginia Electric and Power Company, including, without limitation, its Virginia and North Carolina operations, and all of its subsidiaries.

The Company's accounting practices are generally prescribed by the Uniform System of Accounts promulgated by the regulatory commissions having jurisdiction and are in accordance with generally accepted accounting principles applicable to regulated enterprises. The financial statements include the accounts of the Company and its subsidiaries, with all significant intercompany transactions and accounts being eliminated on consolidation.

The Company is a wholly-owned subsidiary of Dominion Resources, Inc., a Virginia corporation.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent liabilities at the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenues

Revenues are recorded on the basis of services rendered, commodities delivered or contracts settled.

Property, Plant and Equipment

Utility plant is recorded at original cost, which includes labor, materials, services, AFC, where permitted by regulators, and other indirect costs. The cost of maintenance and repairs is charged to the appropriate operating expense and clearing accounts. The cost of additions and replacements is charged to the appropriate utility plant account, except that the cost of minor additions and replacements, as provided in the Uniform System of Accounts, is charged to maintenance expense.

Depreciation and Amortization

Depreciation of utility plant (other than nuclear fuel) is computed on the straight-line method based on projected useful service lives. The cost of depreciable utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation. The provision for depreciation provides for the recovery of the cost of assets including the estimated cost of removal, net of salvage, and is based on the weighted average depreciable plant using a rate of 3.2 percent for 1997, 1996 and 1995.

Operating expenses include amortization of nuclear fuel, which is provided on a unit of production basis sufficient to fully amortize, over the estimated service life, the cost of the fuel plus permanent storage and disposal costs.

Federal Income Taxes

The Company files a consolidated federal income tax return with Dominion Resources.

Deferred investment tax credits are being amortized over the service lives of the property giving rise to such credits.

Allowance for Funds Used During Construction

The applicable regulatory Uniform System of Accounts defines AFC as the cost during the construction period of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.

The pretax AFC rates for 1997, 1996 and 1995 were 6.6 percent, 8.1 percent and 8.9 percent, respectively. No AFC is accrued for approximately 83 percent of the Company's construction work in progress, which is instead included in rate base. A cash return is currently collected on the portion of construction work in progress included in rate base.

Deferred Capacity and Deferred Fuel Expense

Approximately 80 percent of capacity expenses and 90 percent of fuel expenses incurred as part of providing regulated electric service are subject to deferral accounting. The difference between reasonably incurred actual expenses and the level of expenses included in current rates is deferred and matched against future revenues.

Amortization of Debt Issuance Costs

The Company defers and amortizes any expenses incurred in the issuance of long-term debt, including premiums and discounts associated with such debt, over the lives of the respective issues. Any gains or losses resulting from the refinancing of debt are also deferred and amortized over the lives of the new issues of long-term debt as permitted by the appropriate regulatory jurisdictions. Gains or losses resulting from the redemption of debt without refinancing are amortized over the remaining lives of the redeemed issues.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 1997 and 1996, the Company's accounts payable included the net effect of checks outstanding but not yet presented for payment of $55.8 million and $64.8 million, respectively. For purposes of the Consolidated Statements of Cash Flows, the Company considers cash and cash equivalents to include cash on hand and temporary investments purchased with an initial maturity of three months or less.

Commodity Contracts

The trading activities of Virginia Power's wholesale power group include fixed-price forward contracts and the purchase and sale of over-the-counter options that require physical delivery of the underlying commodity. Furthermore, in order to manage price risk associated with natural gas sales and fuel requirements for the utility operations, the Company uses exchange-for-physical contracts, basis swaps, NYMEX natural gas futures contracts, as well as options on natural gas futures contracts.

Options, exchange-for-physical contracts, basis swaps and futures contracts are marked to market with resulting gains and losses reported in earnings, unless such instruments are designated as hedges for accounting purposes. Fixed price forward contracts, initiated for trading purposes, also are marked to market with resulting gains and losses reported in earnings. For exchange-for-physical contracts, basis swaps, fixed price forward contracts and options which require physical delivery of the underlying commodity, market value reflects management's best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Futures contracts and options on futures contracts are marked to market based on closing exchange prices. No contracts were designated as hedges during 1997.

Purchased options and options sold are reported in Deferred Debits and Other Assets — Other and in Deferred Credits and Other Liabilities — Other, respectively, until exercise or expiration. Gains and losses resulting from marking positions to market are reported in Other Income. Net gains and losses resulting from futures contracts and options on futures contracts and settlement of basis swaps are included in Fuel, Net. Amortization of option premiums associated with sales and purchases are included in Revenues — Other and Fuel, Net, respectively. Cash flows from trading activities are reported in Net Cash Flow from Operating Activities.

Reclassification

Certain amounts in the 1996 and 1995 financial statements have been reclassified to conform to the 1997 presentation.

B. Income Taxes:

Details of income tax expense are as follows:

	Years 1997	1996	1995
		(Millions)	
Current expense:			
Federal	$222.1	$185.6	$230.6
State	8.6	2.4	2.1
	230.7	188.0	232.7
Deferred expense:			
Utility plant differences	41.3	65.4	48.9
Deferred fuel and capacity	11.0	22.3	(6.0)
Debt issuance costs	(2.1)	(2.8)	1.3
Terminated construction project costs	(5.8)	(5.1)	(4.4)
Other	(8.9)	(10.7)	(28.1)
	35.5	69.1	11.7
Net deferred investment tax credits-amortization	(16.9)	(16.9)	(16.9)
Total income tax expense	$249.3	$240.2	$227.5

Total federal income tax expense differs from the amount computed by applying the statutory federal income tax rate to pretax income for the following reasons:

	Years 1997	1996	1995
		(Millions)	
Federal income tax expense at statutory rate of 35 percent	$251.4	$244.1	$231.1
Increases (decreases) resulting from:			
Utility plant differences	7.7	5.7	3.2
Ratable amortization of investment tax credits	(16.9)	(16.9)	(16.9)
Terminated construction project costs	5.0	5.0	5.0
State income tax, net of federal tax benefit	4.9	2.4	2.2
Other, net	(2.8)	(0.1)	2.9
	(2.1)	(3.9)	(3.6)
Total income tax expense	$249.3	$240.2	$227.5
Effective tax rate	34.7%	34.4%	34.5%

The Company's net accumulated deferred income taxes consist of the following:

	Years 1997	1996
	(Millions)	
Deferred income tax assets:		
Investment tax credits	$ 84.4	$ 90.3
Deferred income tax liabilities:		
Utility plant differences	1,479.8	1,440.5
Terminated construction project costs	8.6	14.4
Income taxes recoverable through future rates	169.5	168.8
Other	33.5	31.8
Total deferred income tax liabilities	1,691.4	1,655.5
Total net accumulated deferred income taxes	$1,607.0	$1,565.2

C. Nuclear Operations:

Decommissioning

When the Company's nuclear units cease operations, we are obligated to decontaminate or remove radioactive contaminants so that the property will not require NRC oversight. This phase of a nuclear power plant's life cycle is termed decommissioning. While the units are operating, we are collecting from ratepayers amounts that, when combined with investment earnings, will be used to fund this future obligation.

The amount being accrued for decommissioning is equal to the amount being collected from ratepayers and is included in Depreciation and Amortization Expense. The decommissioning collections were $45.8 million, $36.2 million and $28.5 million in 1997, 1996 and 1995, respectively. These dollars are deposited into external trusts through which the funds are invested.

Net earnings of the trusts' investments are included in Other Income in the Company's Consolidated Statements of Income. In 1997, 1996 and 1995, respectively, net earnings were $20.5 million, $16.0 million and $15.9 million. The accretion of the decommissioning obligation is equal to the trusts' net earnings and also is recorded in Other Income. Thus, the net impact of the trusts on Other Income is zero.

The accumulated provision for decommissioning, which is included in Utility Plant Accumulated Depreciation in the Company's Consolidated Balance Sheets, includes the accrued expense and accretion described above and any unrealized gains and losses on the trusts' investments. At December 31, 1997, the net unrealized gains were $149.5 million, which is an increase of $69.0 over the December 31, 1996, amount of $80.5 million. The total accumulated provision for decommissioning at December 31, 1997, was $578.7 million, including $9.6 million accrued in 1997 and deposited to the trusts in January 1998. The provision was $443.3 million at December 31, 1996.

The total estimated cost to decommission the Company's four nuclear units is $1 billion based upon a site-specific study that was completed in 1994. We plan to update this estimate in 1998. The cost estimate assumes that the method of completing decommissioning activities is prompt dismantlement. This method assumes that dismantlement and other decommissioning activities will begin shortly after cessation of operations, which under current operating licenses will begin in 2012 as detailed in the table below.

	Surry		North Anna		Total
	Unit 1	Unit 2	Unit 1	Unit 2	All Units
NRC license expiration year	2012	2013	2018	2020	
	(Millions)				
Current cost estimate (1994 dollars)	$272.4	$274.0	$247.0	$253.6	$1,047.0
Funds in external trusts at 12/31/97	156.5	151.8	134.2	126.6	569.1
1997 contribution to external trusts	10.6	10.8	7.6	7.2	36.2

The Financial Accounting Standards Board (FASB) is reviewing the accounting for nuclear plant decommissioning. In 1996, the FASB tentatively determined that the estimated cost of decommissioning should be reported as a liability rather than as accumulated depreciation and that a substantial portion of the decommissioning obligation should be recognized earlier in the operating life of the nuclear unit. If the industry's accounting were changed to reflect FASB's tentative proposal, then the annual provisions for nuclear decommissioning would increase. During its deliberations, the FASB expanded the scope of the project to include similar unavoidable obligations to perform closure and post-closure activities for non-nuclear power plants. Therefore, any forthcoming standard also may change industry plant depreciation practices. Any impact related to other Company assets cannot be determined at this time.

Insurance

The Price-Anderson Act limits the public liability of an owner of a nuclear power plant to $8.9 billion for a single nuclear incident. The Price-Anderson Amendments Act of 1988 allows for an inflationary provision adjustment every five years. The Company has purchased $200 million of coverage from the commercial insurance pools with the remainder provided through a mandatory industry risk sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the United States, the Company could be assessed up to $81.7 million (including a 3 percent insurance premium tax for Virginia) for each of its four licensed reactors not to exceed $10.3 million (including a 3 percent insurance premium tax for Virginia) per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed.

Nuclear liability coverage for claims made by nuclear workers first hired on or after January 1, 1988, except those arising out of an extraordinary nuclear occurrence, is provided under the Master Worker insurance program. (Those first hired into the nuclear industry prior to January 1, 1988, are covered by the policy discussed above.) The aggregate limit of coverage for the industry is $400 million ($200 million policy limit with automatic reinstatements of an additional $200 million). The Company's maximum retrospective assessment is approximately $12.3 million (including a 3 percent insurance premium tax for Virginia).

The Company's current level of property insurance coverage ($2.55 billion for North Anna and $2.40 billion for Surry) exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. The Company's nuclear property insurance is provided by Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL), two mutual insurance companies, and is subject to retrospective premium assessments, in any policy year in which losses exceed the funds available to these insurance companies. The maximum assessment for the current policy period is $37.0 million. Based on the severity of the incident, the Boards of Directors of the Company's nuclear insurers have the discretion to lower the maximum retrospective premium assessment or eliminate either or both completely. For any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination, the Company has the financial responsibility for these losses.

The Company purchases insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, Virginia Power is subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period's maximum assessment is $8.7 million.

As part owner of the North Anna Power Station, ODEC is responsible for its share of the nuclear decommissioning obligation and insurance premiums applicable to that station, including any retrospective premium assessments and any losses not covered by insurance.

D. Utility Plant:

Utility plant consisted of the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Production	$ 7,684.2	$ 7,691.9
Transmission	1,415.7	1,386.5
Distribution	4,559.2	4,385.4
Other	894.2	862.9
	14,553.3	14,326.7
Construction work in progress	240.9	180.1
Total	$14,794.2	$14,506.8

E. Jointly Owned Plants:

The following information relates to the Company's proportionate share of jointly owned plants at December 31, 1997:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
Ownership interest	60.0%	88.4%	50.0%
		(Millions)	
Utility plant in service	$1,072.9	$1,819.4	$533.3
Accumulated depreciation	229.1	819.2	26.3
Nuclear fuel		403.6	
Accumulated amortization of nuclear fuel		383.4	
Construction work in progress	.1	61.2	1.1

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly owned facilities in the same proportion as their respective ownership interest. The Company's share of operating costs is classified in the appropriate operating expense (fuel, operations and maintenance, depreciation, taxes, etc.) in the Consolidated Statements of Income.

F. Regulatory Assets-Other

Certain expenses normally reflected in income are deferred on the balance sheet as regulatory assets and are recognized in income as the related amounts are included in rates and recovered from customers. The Company's regulatory assets included the following:

	At December 31, 1997	1996
	(Millions)	
Income taxes recoverable through future rates	$478.9	$477.0
Cost of decommissioning DOE uranium enrichment facilities	67.6	73.5
Deferred losses on reacquired debt, net	85.4	91.5
North Anna Unit 3 project termination costs	42.3	73.1
Other	55.1	52.7
Total	$729.3	$767.8

Income taxes recoverable through future rates represent principally the tax effect of depreciation differences not normalized in earlier years for ratemaking purposes. These amounts are amortized as the related temporary differences reverse.

The costs of decommissioning the Department of Energy's (DOE) uranium enrichment facilities have been deferred and represent the unamortized portion of Virginia Power's required contributions to a fund for decommissioning and decontaminating the DOE's uranium enrichment facilities. Virginia Power is making such contributions over a 15-year period with escalation for inflation. These costs are being recovered in fuel rates.

Losses or gains on reacquired debt are deferred and amortized over the lives of the new issues of long-term debt. Gains or losses resulting from the redemption of debt without refinancing are amortized over the remaining lives of the redeemed issues.

The construction of North Anna Unit 3 was terminated in November 1982. All retail jurisdictions have permitted recovery of the incurred costs. For Virginia and FERC jurisdictional customers, the amounts deferred are being amortized from the date termination costs were first includible in rates.

The incurred costs underlying these regulatory assets may represent expenditures by the Company or may represent the recognition of liabilities that ultimately will be settled at some time in the future. For some of those regulatory assets representing past expenditures that are not included in the Company's rate base or used to adjust the Company's capital structure, the Company is not allowed to earn a return on the unrecovered balance. Of the $729.3 million of regulatory assets at December 31, 1997, approximately $57.7 million represent past expenditures that are effectively excluded from rate base by the Virginia State Corporation Commission which has primary jurisdiction over the Company's rates. However, of that amount $42.3 million represent the present value of amounts to be recovered through future rates for North Anna Unit 3 project termination costs, and thus reflect a reduction in the actual dollars to be recovered through future rates for the time value of money. The Company does not earn a return on the remaining $15.4 million of regulatory assets, effectively excluded from rate base, to be recovered over various recovery periods up to 21 years, depending on the nature of the deferred costs.

G. Leases:

Plant and property under capital leases included the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Office buildings (*)	$34.4	$34.4
Data processing equipment	13.3	2.5
Total plant and property under capital leases	47.7	36.9
Less accumulated amortization	17.8	13.3
Net plant and property under capital leases	$29.9	$23.6

(*) The Company leases its principal office building from its parent, Dominion Resources. The capitalized cost of the property under that lease, net of accumulated amortization, represented $22 million and $23 million at December 31, 1997 and 1996, respectively. Rental payments for such lease were $3 million for each of the three years ended December 31, 1997, 1996 and 1995.

The Company is responsible for expenses in connection with the leases noted above, including maintenance.

Future minimum lease payments under noncancellable capital leases and for operating leases that have initial or remaining lease terms in excess of one year as of December 31, 1997, are as follows:

	Capital Leases	Operating Leases
	(Millions)	
1998	$ 7.1	$11.4
1999	6.4	9.9
2000	4.3	7.1
2001	3.2	3.9
2002	3.0	3.2
After 2002	16.7	22.9
Total future minimum lease payments	$40.7	$58.4
Less interest element included above	10.8	
Present value of future minimum lease payments	$29.9	

Rents on leases, which have been charged to operations expense, were $17.6 million, $16.5 million and $13.6 million for 1997, 1996 and 1995, respectively.

Long-term Debt:

Long-term debt included the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
First and Refunding Mortgage Bonds (1):		
Series U, 5.125%, due 1997		$ 49.3
1992 Series B, 7.25%, due 1997		250.0
1988 Series A, 9.375%, due 1998	$ 150.0	150.0
1992 Series F, 6.25%, due 1998	75.0	75.0
1989 Series B, 8.875%, due 1999	100.0	100.0
1993 Series C, 5.875%, due 2000	135.0	135.0
Various series, 6.0-8%, due 2001-2004	805.0	805.0
Various series 6.75%-7.625%, due 2007	415.0	215.0
Various series, 5.45%-8.75%, due 2021-2025	1,144.5	1,144.5
Total First and Refunding Mortgage Bonds	2,824.5	2,923.8
Other long-term debt:		
Term notes:		
Fixed interest rate, 6.15%-10.00%, due 1997-2003	551.1	503.1
Tax exempt financings (2):		
Money Market Municipals, due 2007-2027(3)	488.6	488.6
Convertible interest rate, due 2022	10.0	
Total other long-term debt	1,049.7	991.7
	3,874.2	3,915.5
Less amounts due within one year:		
First and Refunding Mortgage Bonds	225.0	299.3
Term notes	108.5	12.0
Total amount due within one year	333.5	311.3
Less unamortized discount, net of premium	26.1	24.8
Total long-term debt	$3,514.6	$3,579.4

(1) The First and Refunding Mortgage Bonds are secured by a mortgage lien on substantially all of the Company's property.

(2) Certain pollution control facilities at the Company's generating facilities have been pledged or conveyed to secure the financings.

(3) Interest rates vary based on short-term, tax-exempt market rates. For 1997 and 1996, the weighted average daily interest rates were 3.74 percent and 3.57 percent, respectively. Although these bonds are re-marketed within a one year period, they are classified as long-term debt because the Company intends to maintain the debt and they are supported by long-term bank commitments.

The following amounts of debt will mature during the next five years (in millions): 1998 — $333.5; 1999 — $321.0; 2000 — $195.5; 2001 — $160.7; and 2002 — $315.0.

I. Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust:

Virginia Power Capital Trust I (VP Capital Trust) was established as a subsidiary of the Company for the sole purpose of selling $135 million of Preferred Securities (5.4 million shares at $25 par) in 1995. The Company concurrently issued $139.2 million of its 1995 Series A, 8.05% Junior Subordinated Notes (the Notes) in exchange for the $135 million realized from the sale of the Preferred Securities and $4.2 million of common securities of VP Capital Trust. The Preferred Securities and the common securities represent the total beneficial ownership interest in the assets held by VP Capital Trust. The Notes are the sole assets of VP Capital Trust.

The Preferred Securities are subject to mandatory redemption upon repayment of the Notes at a liquidation amount of $25 plus accrued and unpaid distributions, including interest. The Notes are due September 30, 2025. However, that date may be extended up to an additional ten years if certain conditions are satisfied.

J. Preferred Stock Subject to Mandatory Redemption:

The total number of authorized shares for all preferred stock (whether or not subject to mandatory redemption) is 10,000,000 shares. Upon involuntary liquidation, dissolution or winding-up of the Company, all presently outstanding preferred stock is entitled to receive $100 per share plus accrued dividends. Dividends are cumulative.

There are two series of preferred stock subject to mandatory redemption outstanding as of December 31, 1997:

Dividend	Issued and Outstanding Shares	
$5.58	400,000	Shares are non-callable prior to redemption at 3/1/2000
$6.35	1,400,000	Shares are non-callable prior to redemption at 9/1/2000
Total	1,800,000	

There were no redemptions of preferred stock during 1997 or 1996. In 1995, the Company redeemed 417,319 shares of its $7.30 dividend preferred stock subject to mandatory redemption.

K. Preferred Stock Not Subject to Mandatory Redemption:

Shown below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 1997.

		Entitled per Share upon Liquidation		
Dividend	Issued and Outstanding Shares	Amount	Through	And Thereafter to Amounts Declining in Steps to
$5.00	106,677	$112.50		
4.04	12,926	102.27		
4.20	14,797	102.50		
4.12	32,534	103.73		
4.80	73,206	101.00		
7.05	500,000	105.00	7/31/03	$100.00 after 7/31/13
6.98	600,000	105.00	8/31/03	$100.00 after 8/31/13
MMP 1/87 (*)	500,000	100.00		
MMP 6/87 (*)	750,000	100.00		
MMP 10/88 (*)	750,000	100.00		
MMP 6/89 (*)	750,000	100.00		
MMP 9/92, Series A (*)	500,000	100.00		
MMP 9/92, Series B (*)	500,000	100.00		
Total	5,090,140			

(*) Money Market Preferred (MMP) dividend rates are variable and are set every 49 days via an auction process. The combined weighted average rates for these series in 1997, 1996 and 1995, including fees for broker/dealer agreements, were 4.71 percent, 4.48 percent and 4.93 percent, respectively.

In 1995, the Company redeemed 400,000 shares of its $7.45 dividend preferred stock not subject to mandatory redemption and 450,000 shares of its $7.20 dividend preferred stock not subject to mandatory redemption.

L. Common Stock:

There were no changes in the number of authorized and outstanding shares of the Company's Common Stock during the three years ended December 31, 1997.

M. Short-term Debt:

The Company's commercial paper program has a maximum borrowing capacity of $500 million. It is supported by two credit facilities. One is a $300 million, five-year credit facility that was effective on June 7, 1996, and expires on June 7, 2001. The other is a $200 million credit facility that originated on June 7, 1996, with an initial term of 364 days and provisions for subsequent 364-day extensions. It was renewed on June 6, 1997, for 364 days.

The total amount of commercial paper outstanding as of December 31, 1997, was $226.2 million with a weighted average interest rate of 5.88 percent. This represents a decrease of $86.2 million from the December 31, 1996, balance of $312.4 million and a weighted average interest rate of 5.51 percent.

N. Retirement Plan, Postretirement Benefits and Other Benefits:

Under the terms of its benefit plans, the Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Retirement Plan

The Company participates in the Dominion Resources, Inc. Retirement Plan (the Retirement Plan), a defined benefit pension plan. The benefits are based on years of service and average base compensation over the consecutive 60-month period in which pay is highest.

The Company's pension plan expenses were $20.6 million, $24.8 million and $20.3 million for 1997, 1996 and 1995, respectively, and the amounts funded by the Company were $27.0 million, $28.4 million and $42.7 million in 1997, 1996 and 1995, respectively.

Postretirement Benefits

In addition to providing pension benefits, Dominion Resources and the Company provide certain health care and life insurance benefits for retired employees. Health care benefits are provided to retirees who have completed at least 10 years of service after attaining age 45. These and similar benefits for active employees are provided through insurance companies. Under the terms of its benefit plans, the Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Net periodic postretirement benefit expense was as follows:

	Year Ended December 31, 1997	1996
	(Millions)	
Service cost	$ 12.3	$ 12.1
Interest cost	25.1	23.9
Return on plan assets	(25.3)	(16.6)
Amortization of transition obligation	12.1	12.1
Net amortization and deferral	13.4	7.1
Net periodic postretirement benefit expense	$ 37.6	$ 38.6

The following table sets forth the funded status of the plan:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Fair value of plan assets	$ 176.6	$ 133.0
Accumulated postretirement benefit obligation:		
Retirees	$ 224.5	$ 201.7
Active plan participants	136.3	122.2
Accumulated postretirement benefit obligation	360.8	323.9
Accumulated postretirement benefit obligation in excess of plan assets	(184.2)	(190.9)
Unrecognized transition obligation	180.8	192.8
Unrecognized net experience (gain)/loss	(1.8)	(3.6)
Accrued postretirement benefit cost	$ (5.2)	$ (1.7)

A one percent increase in the health care cost trend rate would result in an increase of $5.0 million in the service and interest cost components and a $39.5 million increase in the accumulated postretirement benefit obligation.

Significant assumptions used in determining the postretirement benefit obligation were:

	1997	1996
Discount rates	7.75%	8%
Assumed return on plan assets	9%	9%
Medical cost trend rate	6% for 1st year	7% for 1st year
	5% for 2nd year	6% for 2nd year
	Scaling down to 4.75% beginning in the year 2000	Scaling down to 4.75% beginning in the year 2000

The Company is recovering these costs in rates on an accrual basis in all material respects, in all jurisdictions. The funds being collected for Other Postretirement Benefits (OPEB) in rates, in excess of OPEB benefits actually paid during the year, are contributed to external benefit trusts under the Company's current funding policy (see Future Issues — *Competition — Exposure to Potentially Stranded Costs* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS).

O. Restructuring:

The Company announced the implementation phase of its Vision 2000 program in March 1995. During this phase, the Company began reviewing operations with the objective of outsourcing services where economical and appropriate and re-engineering the remaining functions to streamline operations. The re-engineering process has resulted in outsourcing, decentralization, reorganization and downsizing for portions of the Company's operations. As part of this process, the Company has reevaluated its utilization of capital resources in the operations of the Company to identify further opportunities for operational efficiencies through outsourcing or re-engineering of its processes.

Restructuring charges of $18.4 million, $64.9 million, and $117.9 million in 1997, 1996 and 1995, respectively, included severance costs, purchased power contract restructuring and negotiated settlement costs, capital project cancellation costs, and other costs incurred directly as a result of the Vision 2000 initiatives. While the Company may incur additional charges for severance in 1998, the amounts are not expected to be significant.

Employee Severance

In 1995, the Company established a comprehensive involuntary severance package for salaried employees who may no longer be employed as a result of these initiatives. The Company is recognizing the cost associated with employee terminations in accordance with Emerging Issues Task Force Consensus No. 94-3 as management identifies the positions to be eliminated. Severance payments will be made over a period not to exceed twenty months. Through December 31, 1997, management had identified 1,977 positions to be eliminated. The recognition of severance costs resulted in charges to operations in 1997, 1996 and 1995 of $12.5 million, $49.2 million and $51.2 million, respectively. At December 31, 1997, 1,619 employees had been terminated and severance payments totaling $74 million had been paid. The Company estimates that hese staffing reductions will result in annual savings, in the range of $80 million to $90 million. However, such savings are being offset by salary increases, outsourcing costs and increased payroll costs associated with staffing for growth opportunities.

Purchased Power Contracts

In an effort to minimize its exposure to potential stranded investment, the Company is evaluating its long-term purchased power contracts and negotiating modifications to their terms, including cancellations, where it is determined to be economically advantageous to do so. The Company has also negotiated settlements with several other parties to terminate their rights to sell power to the Company. The cost of contract modifications, contract cancellations and negotiated settlements was $3.8 million, $7.8 million and $8.1 million in 1997, 1996 and 1995, respectively. Using contract terms, estimated quantities of power that would have otherwise been delivered and other relevant factors at the time of each transaction, the Company estimated that its annual future purchased power costs, including energy payments, would be reduced by up to $0.8 million, $5.8 million and $147.0 million for the 1997, 1996 and 1995 transactions, respectively. The cost of alternative sources of power that might ultimately be required as a result of these settlements is expected to be significantly less than the estimated reduction in purchased power costs.

Construction Project

Restructuring charges reported in 1995 included $37.3 million for the cancellation of a project to construct a facility to handle low level radioactive waste at the Company's North Anna Power Station. As a result of reevaluating the handling of low level radioactive waste, the Company concluded that the facility should not be completed due to the additional capital investment required, decreased Company volumes of low level radioactive waste resulting from improvements in station procedures and the availability of more economical offsite processing.

P. Accelerated Cost Recovery:

In this increasingly competitive environment, the Company also has concluded that it is appropriate to utilize available cost reductions, such as those generated by the Vision 2000 program (see Note O to the CONSOLIDATED FINANCIAL STATEMENTS), to accelerate the write-off of existing unamortized regulatory assets. Not only will this strategically position the Company in anticipation of competition, but it also reflects the Company's commitment to mitigate its exposure to potentially stranded costs (see Competition in MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS). The Company identified savings of $38.4 million in 1997 and $26.7 million in 1996 which were used to establish a reserve for expected adjustments to regulatory assets.

Q. Commitments and Contingencies:

The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Utility Rate Regulation

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. In March 1997, Virginia Power filed its Alternative Regulatory Plan (ARP) based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational

Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

Retrospective Premium Assessments

Under several of the Company's nuclear insurance policies, the Company is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to these insurance companies. For additional information, see Note C to CONSOLIDATED FINANCIAL STATEMENTS.

Construction Program

The Company has made substantial commitments in connection with its construction program and nuclear fuel expenditures. Those expenditures are estimated to total $588.1 million (excluding AFC) for 1998. The Company presently estimates that all of its 1998 construction expenditures, including nuclear fuel, will be met through cash flow from operations.

Purchased Power Contracts

Since 1984, the Company has entered into contracts for the long-term purchases of capacity and energy from other utilities, qualifying facilities and independent power producers. The Company has 57 non-utility purchase contracts with a combined dependable summer capacity of 3,277 MW.

The table below reflects the Company's minimum commitments as of December 31, 1997, for power purchases from utility and non-utility suppliers.

Year	Commitment Capacity	Commitment Other
	(Millions)	
1998	$ 813.5	$154.9
1999	816.7	156.7
2000	723.8	92.0
2001	716.0	83.7
2002	721.1	81.5
Later years	9,069.6	388.2
Total	$12,860.7	$957.0
Present value of the total	$ 5,878.0	$553.3

Payments made by Virginia Power in satisfaction of the minimum purchase commitments shown in the above table are subject to reduction or partial refund if (1) the non-utility suppliers fail to meet performance requirements or (2) changes in federal or state law or administrative actions disallow or have the effect of disallowing Virginia Power's recovery of such costs from its customers. The amount of such payment reductions or refunds, if any, will be determined and administered as provided in individual supply contracts, although (1) the deferral of refund obligations, (2) disputes over the applicability of such payment reductions or refund obligations and (3) the ability of some non-utility suppliers to make refunds could limit Virginia Power's ability to benefit from these contract provisions.

In addition to the minimum purchase commitments in the table above, under some of these contracts, the Company may purchase, at its option, additional power as needed. Actual payments for purchased power (including economy, emergency, limited term, short-term and other purchases for utility operations, as well as for trading purposes) for the years 1997, 1996 and 1995 were $1,381 million, $1,183 million and $1,093 million, respectively. For a discussion of the Company's efforts to restructure certain purchased power contracts, see Note O to CONSOLIDATED FINANCIAL STATEMENTS.

Fuel Purchase Commitments

The Company's estimated fuel purchase commitments for the next five years for system generation are as follows (millions): 1998 — $293; 1999 — $233; 2000 — $144; 2001 — $144; and 2002 — $127.

Sale of Power

The Company enters into agreements with other utilities and with other parties to purchase and sell capacity and energy. These agreements may cover current and future periods ("forward positions"). The volume of these transactions varies from day to day based on the market conditions, our current and anticipated load, and other factors. The combined amounts of sales and purchases range from 500 MW to 7,000 MW at various times during a given year. These operations are closely monitored from a risk management perspective.

Environmental Matters

The Company is subject to rising costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations of the Company. These costs have been historically recovered through the ratemaking process; however, should material costs be incurred and not recovered through rates, the Company's results of operations and financial condition could be adversely impacted.

Site Remediation

The EPA has identified the Company and several other entities as Potentially Responsible Parties (PRPs) at two Superfund sites located in Kentucky and Pennsylvania. The estimated future remediation costs for the sites are in the range of $61.5 million to $72.5 million. The Company's proportionate share of the cost is expected to be in the range of $1.7 million to $2.5 million, based upon allocation formulas and the volume of waste shipped to the sites. The Company has accrued a reserve of $1.7 million to meet its obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, the Company has determined that it is probable that the PRPs will fully pay the costs apportioned to them.

The Company and Dominion Resources have remedial action responsibilities remaining at two coal tar sites. The Company accrued a $2 million reserve to meet its estimated liability based on site studies and investigations performed at these sites. In addition, two civil actions have been instituted against the City of Norfolk and Virginia Power by property owners who allege that their property has been contaminated by toxic pollutants originating from one of the coal tar sites now owned by the City of Norfolk and formerly owned by the Company. The first civil action reached settlement without trial in September 1997. The remaining plaintiff is seeking compensatory damages of $2 million and punitive damages of $1 million. It is too early in this case for the Company to predict the outcome. The Company has filed answers denying liability. No trial date has been set.

The Company generally seeks to recover its costs associated with environmental remediation from third party insurers. At December 31, 1997, any pending or possible claims were not recognized as an asset or offset against recorded obligations of the Company.

R. Fair Value of Financial Instruments:

The Company used available market information and appropriate valuation methodologies to estimate the fair value of each class of financial instrument for which it is practicable to estimate fair value. These estimates are not necessarily indicative of the amounts the Company could realize in a market exchange. In addition, the use of different market assumptions may have a material effect on the estimated fair value amounts.

	December 31,			
	1997		1996	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Assets:				
Cash and cash equivalents	$ 36.0	$ 36.0	$ 47.9	$ 47.9
Nuclear decommissioning trust funds	569.1	569.1	443.3	443.3
Liabilities and capitalization:				
Short-term debt	226.2	226.2	312.4	312.4
Long-term debt:				
First and Refunding Mortgage Bonds	2,824.5	2,937.7	2,923.8	2,957.4
Medium-term notes	551.1	573.7	503.1	531.3
Money Market Municipal tax-exempt securities	488.6	488.6	488.6	488.6
Convertible interest rate tax-exempt bonds	10.0	10.4		
Preferred stock subject to mandatory redemption	180.0	186.6	180.0	185.8
Preferred securities of subsidiary trust	135.0	137.7	135.0	135.0

Cash and cash equivalents and short-term debt: The carrying amount of these items approximates fair value because of their short maturity.

Nuclear decommissioning trust funds: The fair value is based on available market information and generally is the average of bid and asked price.

First and Refunding Mortgage Bonds: Fair value is based on market quotations.

Medium-term notes: These notes were valued by discounting the remaining cash flows at a rate estimated for each issue. A yield curve rate was estimated to relate Treasury Bond rates for specific issues to the corresponding maturities.

Money Market Municipal tax-exempt securities: The interest rates for these notes vary so that fair value approximates carrying value.

Convertible interest rate tax-exempt bonds and preferred stock subject to mandatory redemption: The fair value is based on market quotations or is estimated by discounting the dividend and principal payments for a representative issue of each series over the average remaining life of the series.

Preferred securities of subsidiary trust: Fair value is based on market quotations.

S. Quarterly Financial Data (unaudited):

The following amounts reflect all adjustments, consisting of only normal recurring accruals (except as discussed below), necessary in the opinion of the management for a fair statement of the results for the interim periods.

Quarter	Revenues	Income from Operations	Net Income	Balance Available for Common Stock
		(Millions)		
1997				
1st	$1,174.8	$248.6	$110.3	$101.5
2nd	1,051.5	184.6	72.3	63.3
3rd	1,499.9	381.0	201.1	192.1
4th	1,352.8	205.1	85.4	76.5
1996				
1st	$1,169.7	$311.1	$152.8	$143.8
2nd	1,032.1	224.0	96.6	87.8
3rd	1,180.8	325.8	162.2	153.3
4th	1,038.3	149.1	45.7	36.9

Results for interim periods may fluctuate as a result of weather conditions, rate relief and other factors.

Certain accruals were recorded in 1997 and 1996 that are not ordinary, recurring adjustments, consisting of restructuring (see Note O to CONSOLIDATED FINANCIAL STATEMENTS) and accelerated cost recovery (see Note P to CONSOLIDATED FINANCIAL STATEMENTS).

Restructuring — The Company expensed $6.3 million, $1.4 million and $10.7 million during the second, third and fourth quarters of 1997, respectively, and $5.4 million, $19.3 million, $4.6 million and $35.6 million during the first, second, third and fourth quarters of 1996.

Accelerated cost recovery — Amounts reserved for accelerated cost recovery were $2.8 million, $28.3 million and $7.3 million during the second, third and fourth quarters of 1997, respectively, and $26.7 million during the fourth quarter of 1996.

Charges for restructuring and accelerated cost recovery reduced Balance Available for Common Stock by $5.8 million, $19.3 million, and $11.7 million for the second, third, and fourth quarters of 1997, respectively, and $3.5 million, $12.5 million, $3.0 million and $40.6 million for first, second, third and fourth quarters of 1996.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

On September 12, 1997, the Board of Directors elected Thos. E. Capps as Chairman, succeeding John B. Adams, Jr., who had held the position since 1994. Mr. Capps also is Chairman of the Board of Directors of Dominion Resources, Inc., the parent company of Virginia Power.

(a) Information concerning directors of Virginia Electric and Power Company is as follows:

Name and Age	Principal Occupation for Last 5 Years, Directorships in Public Corporations	Year First Elected a Director	Term Expires
Thos. E. Capps (62)	Chairman of the Board of Directors of Virginia Electric and Power Company from September 12, 1997 to date and Chairman, President and Chief Executive Officer of Dominion Resources from September 1, 1995 to date (from August 15, 1994 to September 1, 1995, Chairman and Chief Executive Officer; prior to August 15, 1994, Chairman, President and Chief Executive Officer). He is a Director of Bassett Furniture Industries, Inc. and NationsBank Corporation.	1986	2000
Norman Askew (55)	President and Chief Executive Officer of Virginia Electric and Power Company and Executive Vice President of Dominion Resources from August 1, 1997 to date; Executive Vice President of Dominion Resources and Chief Executive of East Midlands from February 21, 1997 to August 1, 1997; Chief Executive of East Midlands from April 1, 1994 to February 21, 1997; Managing Director prior to April 1, 1994.	1997	1998
John B. Adams, Jr. (53)	President and Chief Executive Officer of The Bowman Companies, Fredericksburg, Virginia, a manufacturer and bottler of alcohol beverages and he is a Director of Dominion Resources.	1987	1998
John B. Bernhardt (68)	Managing Director, Bernhardt/Gibson Financial Opportunities, financial services, Newport News, Virginia. He is a Director of Resource Bank and Dominion Resources.	1986	2000
James F. Betts (65)	Former Chairman of the Board and President, The Life Insurance Company of Virginia, Richmond, Virginia. He is a Director of Wachovia Corporation.	1978	2000
Jean E. Clary (53)	President and owner of Century 21 Clary and Associates, Inc., South Hill, Virginia.	1996	2000
John W. Harris (50)	President, The Harris Group, a real estate consulting firm, Charlotte, North Carolina. He is a Director of Piedmont Natural Gas Company, Inc. and US Airways Group, Inc.	1997	1998
Benjamin J. Lambert, III (61)	Optometrist, Richmond, Virginia. He is a Director of Consolidated Bank and Trust Company, Student Loan Marketing Association (SallieMae) and Dominion Resources.	1992	1998
Richard L. Leatherwood (58)	Retired, Baltimore, Maryland. Former President and Chief Executive Officer, CSX Equipment, an operating unit of CSX Transportation, Inc.). He is a Director of Dominion Resources and CACI International, Inc.	1994	1998
Harvey L. Lindsay, Jr. (68)	Chairman and Chief Executive Officer of Harvey Lindsay Commercial Real Estate, Norfolk, Virginia, a commercial real estate firm. He is a Director of Dominion Resources.	1986	1999
Kenneth A. Randall (70)	Corporate Director for various companies, Williamsburg, Virginia. He is a Director of Oppenheimer Funds, Inc., Kemper Insurance Companies and Prime Retail, Inc. He is a Director of Dominion Resources.	1971	1999

William T. Roos (69)	Retired, Hampton, Virginia (prior to December 31, 1993, President of Penn Luggage, Inc., retail specialty stores). He is a Director of Dominion Resources.	1975	1999
Frank S. Royal (58)	Physician, Richmond, Virginia. He is a Director of Columbia/HCA Healthcare Corporation, Crestar Financial Corporation, Chesapeake Corporation, CSX Corporation and Dominion Resources.	1997	1998
Judith B. Sack (49)	Senior Advisor, Morgan Stanley & Co., Inc., an investment banking firm, New York, New York, as of September 1, 1995 (prior to September 1, 1995, Advisor). She is a Director of Dominion Resources.	1997	1999
S. Dallas Simmons (58)	President of Virginia Union University, Richmond, Virginia. He is a Director of Dominion Resources.	1997	2000
Robert H. Spilman (70)	President, Spilman Properties, Basset, Virginia and Chairman of the Board and a Director of Jefferson-Pilot Corp., Greensboro, North Carolina. Retired Chairman and Chief Executive Officer of Bassett Furniture Industries, Inc. He is a Director of International Home Furnishing Center, The Pittston Company and Dominion Resources.	1994	2000
William G. Thomas (58)	President of Hazel & Thomas, Alexandria, Virginia, a law firm.	1987	1999
David A. Wollard (60)	Retired President, Bank One Colorado, N.A., Denver, Colorado.	1997	1999

The Directors are divided into three classes, with staggered terms. Each class consists, as nearly as possible, of one-third of the total number of Directors. Each Director holds office until the annual meeting for the year in which his class term expires, or until his successor is duly qualified and elected as provided in the Company's Articles of Incorporation.

Mr. Thomas has entered into a Consent Decree with the Office of Thrift Supervision in connection with the lending and credit granting activities of Perpetual Savings Bank, FSB, which Mr. Thomas formerly served as a director. The Consent Decree requires that Mr. Thomas obtain approval from the appropriate federal banking agency before accepting certain positions involving lending or credit activities with an insured depository institution.

(b) Information concerning the executive officers of Virginia Electric and Power Company is as follows:

Name and Age	Business Experience past Five Years
Norman Askew (55)	President and Chief Executive Officer of Virginia Electric and Power Company and Executive Vice President of Dominion Resources from August 1, 1997 to date; Executive Vice President of Dominion Resources and Chief Executive of East Midlands from February 21, 1997 to August 1, 1997; Chief Executive of East Midlands from April 1, 1994 to February 21, 1997; Managing Director prior to April 1, 1994.
Thomas F. Farrell, II (43)	Executive Vice President of Virginia Electric and Power Company and Senior Vice President-Corporate Affairs of Dominion Resources, September 1, 1997 to date; Senior Vice President-Corporate & General Counsel of Dominion Resources, January 1, 1997 to September 1, 1997; Vice President and General Counsel of Dominion Resources, July 1, 1995 to January 1, 1997; Partner in the law firm of McGuire, Woods, Battle, & Boothe LLP prior to July 1, 1995.
Robert E. Rigsby (48)	Executive Vice President, January 1, 1996 to date; Senior Vice President-Finance and Controller, January 1, 1995 to January 1, 1996; Vice President-Human Resources prior to January 1, 1995.
William R. Cartwright (55)	Senior Vice President-Fossil and Hydro, July 1, 1995 to date; Vice President Fossil and Hydro prior to July 1, 1995.
Lawrence E. De Simone (50)	Senior Vice President-Energy Services, July 15, 1996 to date; vice president-strategic planning for Central & South West Corp., a Dallas-based electric utility holding company, prior to July 15, 1996.
Larry M. Girvin (54)	Senior Vice President-Commercial Operations, January 1, 1996 to date; Vice President-Human Resources, January 1, 1995 to January 1, 1996; Vice President-Nuclear Services prior to January 1, 1995.
James P. O'Hanlon (54)	Senior Vice President-Nuclear, June 1, 1994 to date; Vice President-Nuclear Operations prior to June 1, 1994.

John A. Shaw (49)	Senior Vice President-Finance, March 16, 1998 to date; Vice President Financial Service for ARCO Chemical Company, Philadelphia, Pennsylvania, prior to March 16, 1998. During the past 5 years, he has also served as Treasurer and Controller of ARCO Chemical.
Eva S. Teig (53)	Senior Vice President-External Affairs & Corporate Communications, September 1, 1997 to date; Vice President-External Affairs & Corporate Communications, June 1, 1997 to September 1, 1997; Vice President-Public Affairs prior to June 1, 1997.
Said Ziai (44)	Senior Vice President-Corporate Strategy, October 1,1997 to date; Corporate Planning Director, East Midlands Electricity plc, Nottingham, England prior to October 1, 1997.
Thomas L. Caviness, Jr. (52)	Vice President-Retail Energy Services, July 1, 1995 to date;Vice President-Eastern Division prior to July 1, 1995.
David A. Christian (43)	Site Vice President-Surry, March 1, 1998 to date; Station Manager-Surry Power Station, September 1, 1994 to March 1, 1998; Assistant Station Manager-Surry, prior to September 1, 1994.
J. Kennerly Davis, Jr. (52)	Vice President-Finance and Administrative Services, Treasurer and Corporate Secretary, January 1, 1996 to date; Vice President, Treasurer and Corporate Secretary, October 1, 1994 to January 1, 1996; Vice President and Corporate Secretary of Dominion Resources prior to October 1, 1994.
James T. Earwood, Jr. (54)	Vice President-Bulk Power Delivery, January 1, 1997 to date;Vice President-Energy Efficiency and Division Services, January 1, 1996 to January 1, 1997; Vice President-Division Services prior to January 1, 1996.
E. Paul Hilton (54)	Vice President-Regulation, October 1, 1997 to date; Manager, Rates and Regulation, February 20, 1996 to October 1, 1997; Manager, Rates prior to February 20, 1996.
Thomas A. Hyman, Jr. (46)	Vice President-Distribution Operations and North Carolina Power, June 1, 1997 to date;Vice President-Eastern Division and North Carolina Power, July 1, 1995 to June 1, 1997; Vice President-Southern Division, June 1, 1994 to July 1, 1995; Station Manager-Bremo Power Station prior to June 1, 1994.
Michael R. Kansler (43)	Vice President-Nuclear Operations, January 1, 1997 to date;Vice President-Nuclear Engineering and Services, October 1, 1995 to January 1, 1997; Vice President-Nuclear Services, January 1, 1995 to October 1, 1995 ; Manager-Nuclear Operations Support, September 1, 1994 to January 1, 1995; Station Manager-Surry Nuclear Power Station prior to September 1, 1994.
William R. Matthews (51)	Site Vice President-North Anna, March 1, 1998 to date; Station Manager-North Anna Power Station, May 1, 1996 to March 1, 1998; Assistant Station Manager-North Anna Power Station, December 1, 1993 to May 1, 1996; Superintendent-Maintenance, prior to December 1, 1993.
Mark F. McGettrick (40)	Vice President-Customer Service, January 1, 1997 to date; Corporate Restructuring Project Manager, February 1, 1995 to January 1, 1997; Assistant Controller prior to February 1, 1995.
William S. Mistr (50)	Vice President-Information Technology, January 1, 1996 to date and Vice President of Dominion Resources, February 20, 1997 to date; Vice President and Treasurer, Dominion Energy, Inc., October 1, 1994 to January 1, 1996; Assistant Treasurer, Dominion Resources prior to October 1, 1994.
Thomas J. O'Neil (55)	Vice President-Human Resources, January 1, 1996 to date; Vice President-Energy Efficiency prior to January 1, 1996.
Edward J. Rivas (53)	Vice President-Fossil & Hydro Operations, January 1, 1998 to date; Manager-Clover Power Station, March 16, 1994 to January 1, 1998; Manager-Fossil & Hydro Training prior to March 16, 1994.
Robert F. Saunders (54)	Vice President-Nuclear Engineering and Services, January 1, 1997 to date; Vice President-Nuclear Operations, June 1, 1994 to January 1, 1997; Assistant Vice President-Nuclear Operations, prior to June 1, 1994.
Johnny V. Shenal (52)	Vice President-Distribution Construction, June 1, 1997 to date;Vice President-Northern and Western Divisions, June 1, 1994 to June 1, 1997; Vice President-Western Division, prior to June 1, 1994.
Richard T. Thatcher (48)	Vice President-Wholesale Power Group, September 1, 1997 to date; Managing Director, Wholesale Power, April 10, 1997 to September 1, 1997; Manager, Wholesale Power Group, July 1, 1995 to April 10, 1997; Project Manager, January 1, 1995 to July 1, 1995; Director-Generation and Interconnection Planning prior to January 1, 1995.

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

Section 16(a) Beneficial Ownership Reporting Compliance

Our Directors and Executive Officers report their ownership of our preferred stock pursuant to Section 16(a) of the Exchange Act. Through administrative oversight, the following individuals failed to file their initial statements of beneficial ownership on Form 3 on a timely basis: Thos. E. Capps, Norman Askew, John B. Bernhardt, John W. Harris, Kenneth A. Randall, Frank S. Royal, Judith B. Sack, S. Dallas Simmons, David A. Wollard, Thomas F. Farrell, II, Said Ziai, E. Paul Hilton, Richard T. Thatcher, David A. Christian and William R. Matthews.

None of the individuals owned any of our preferred stock at the time their initial reports should have been filed nor have they or any other Director or Executive Officer have any reportable transactions in the preferred stock which have not been reported. The required filings have now been made.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Table

The Summary Table below includes compensation paid by the Company for services rendered in 1997, 1996 and 1995 for the Chief Executive Officer and the four other most highly compensated executive officers (as of December 31, 1997) as determined by total salary and incentive payments for 1997.

Summary Compensation Table

		Annual Compensation			Long Term Compensation Awards		Payouts	
Name & Principal Position	Year	Salary	Incentive(1)	Other Annual Compensation(2)	Restricted Stock Awards	Securities Underlying Options/ SAR Grants	LTIP Pay out	All Other Compensation(3)
James T. Rhodes	1997	$244,800	$159,250(4)	$ 0	$ 0	$0	$803,429(5)	$7,977,039(6)
President and CEO	1996	$410,575	$247,606	$ 0	$ 0	$0	$ 75,684	$ 4,500
(retired August 1, 1997)	1995	$406,075	$273,000	$ 0	$ 0	$0	$ 77,970	$ 4,500
Norman Askew	1997	$177,084	$ 85,833	$14,560	$ 0(7)	$0	$ 18,791(8)	$ 120,000(9)
President and CEO								
(effective August 1, 1997)								
Robert E. Rigsby	1997	$254,850	$129,920	$ 0	$ 0(10)	$0	$ 83,171(11)	$ 4,800
Executive Vice President	1996	$226,469	$143,892	$ 0	$ 0	$0	$ 43,157	$ 4,500
	1995	$171,456	$105,000	$ 0	$ 0	$0	$ 34,569	$ 4,500
James P. O'Hanlon	1997	$270,250	$110,240	$ 0	$ 0(12)	$0	$ 80,140(13)	$ 4,800
Senior Vice President —	1996	$220,815	$128,511	$ 0	$ 0	$0	$ 56,152	$ 4,500
Nuclear	1995	$207,555	$136,400	$ 0	$ 0	$0	$ 45,109	$ 4,500
Lawrence E. DeSimone	1997	$212,751	$ 85,520	$ 0	$ 0(14)	$0	$ 0	$ 3,180
Senior Vice President —	1996	$ 94,419	$ 50,441	$ 0	$ 0	$0	$ 0	$ 0
Energy Services								
Larry M. Girvin	1997	$187,050	$ 85,520	$ 0	$ 0(15)	$0	$ 52,935(16)	$ 4,800
Senior Vice President —	1996	$164,600	$ 89,200	$ 0	$ 0	$0	$ 30,717	$ 4,500
Commercial Operations	1995	$139,650	$ 66,606	$ 0	$ 0	$0	$ 24,685	$ 4,500

(1) The Company does not maintain "bonus" plans which are used by some companies to supplement salaries based on the success of the company without regard to individual performance. However, the Company has in place various incentive plans that compensate officers and employees for achieving specified performance goals.

(2) Unless noted, none of the executive officers above received perquisites or other personal benefits in excess of either $50,000 or 10% of total salary and incentive payment.

(3) Employer matching contribution of $4,800 on Employee Savings Plan contributions, unless otherwise noted.

(4) Amount represents a lump sum settlement of his rights under the 1997 Annual Incentive Plan.

(5) $158,025 was paid under the 1995-1997 Performance Achievement Plan. 7,326 shares of Dominion Resources, Inc. Common Stock (worth $269,231 @ $36.75 per share) were issued under the 1996-1998 Long Term Incentive Plan. 10,326 shares of Dominion Resources, Inc. Common Stock (worth $376,173 @ $36.75 per share) were issued under the 1997-1999 Long Term Incentive Plan.

(6) Upon his retirement, Dr. Rhodes received the following payments from the Company: $51,078 for unused vacation; $1,023,271 as provided by his employment contract; $4,184,220 lump sum settlement of pension benefits not payable from the qualified retirement plan; $2,715,926 as a lump sum settlement of his benefit under the Executive Supplemental Retirement Plan, and $2,544 in employer match on Employee Savings Plan contributions.

(7) Mr. Askew held no restricted stock as of 12/31/97.

(8) Amount represents incentive plan pay outs from Virginia Power, on a prorated basis, for performance cycles that ended in 1997: $7,550 in lieu of dividends on restricted stock for partial participation in the 1996-1998 and the 1997-1999 performance cycles; and $11,241 for the 1995-1997 performance cycle.

(9) A one time payment related to his international transfer from the UK to the US.

(10) Aggregate number of shares of restricted stock on December 31, 1997: 13,763 with an aggregate value of $585,788 (based on a closing price on December 31, 1997 of $42.5625 per share).

(11) 2,085 shares of stock, with 50% of the value awarded in cash ($41,133) and the remaining 1,042 shares being issued (valued at $42,038 or $40.3437 per share as of 2/20/98).

(12) Aggregate number of shares of restricted stock on December 31, 1997: 9,773 with aggregate value of $415,963 (closing price on December 31, 1997 of $42.5625 per share).

(13) 2,009 shares of stock, with 50% of the value awarded in cash ($39,635) and the remaining 1,004 shares being issued (valued at $40,505 or $40.3437 per share as of 2/20/98).

(14) Mr. DeSimone held no restricted stock as of 12/31/97.

(15) Aggregate number of shares of restricted stock on December 31, 1997: 7,528 with aggregate value of $320,411 (closing price on December 31, 1997 of $42.5625 per share).

(16) 1,327 shares of stock, with 50% of the value awarded in cash ($26,187) and the remaining 663 shares being issued (valued at $26,748 or $40.3437 per share as of 2/20/98).

Long-term Incentive Compensation

Long-term incentive awards made during 1997 are shown in the following table.

Long-term Incentive Plans — Awards in the Last Fiscal Year

1997-1999 Long-term Incentive Plan

Name	Number of Shares, Units or Other Rights(#)	Performance or Other Period until Maturation or Payout	Estimated Future Payouts under Non-stock Price Based Plans: Threshold ($ or #)	Estimated Future Payouts under Non-stock Price Based Plans: Target ($ or #)
J.T. Rhodes	$259,448	3 years	$129,724	$259,448
N. Askew	$261,250	3 years	$130,625	$261,250
J.P. O'Hanlon	$112,843	3 years	$ 56,422	$112,843
R.E. Rigsby	$163,714	3 years	$ 81,857	$163,714
L.E. DeSimone	$ 87,750	3 years	$ 43,875	$ 87,750
L.M. Girvin	$ 87,750	3 years	$ 43,875	$ 87,750

Retirement Plans

The table below sets forth the estimated annual straight life benefit that would be paid following retirement under the benefit formula of the Dominion Resources, Inc. Retirement Plan (the Retirement Plan).

Estimated Annual Benefits Payable upon Retirement

	Credited Years of Service			
Final Average Earnings	**15**	**20**	**25**	**30**
$185,000	$51,501	$68,668	$85,836	$103,003
200,000	56,069	74,758	93,448	112,138
225,000	63,681	84,908	106,136	127,363
250,000	71,294	95,058	118,823	142,588
300,000	86,519	115,358	144,198	173,038
350,000	101,744	135,658	169,573	203,488
400,000	116,969	155,958	194,948	233,938
450,000	132,194	176,258	220,323	264,388
500,000	147,419	196,558	245,698	294,838
550,000	162,644	216,858	271,073	325,288
600,000	177,869	237,158	296,448	355,738
650,000	193,094	257,458	321,823	386,188
750,000	223,544	298,058	372,573	447,088

Benefits under the Retirement Plan are based on (i) average base compensation over the consecutive 60-month period in which pay is highest, (ii) years of credited service, (iii) age at retirement, and (iv) the offset of Social Security Benefits.

Certain officers have entered into retirement agreements that give additional credited years of service for retirement and retirement life insurance purposes, and retirement medical benefit purposes contingent upon the officer reaching a specified age and remaining in the employ of the Company or an affiliate.

For purposes of the above table, based on 1997 compensation, credited years of service (including any additional years earned in connection with the retirement agreements) for each of the individuals named in the cash compensation table would be as follows:

James T. Rhodes: 30; Norman Askew: 0; Robert E. Rigsby: 26; James P. O'Hanlon: 8; Lawrence E. De Simone: 0; Larry M. Girvin: 31.

Virginia Power's executive compensation program has placed increased emphasis on incentive compensation opportunities linked to financial and operating performance. Base salaries have been held below the mean for comparable positions at comparable companies. The Retirement Plan benefit formula recognizes base salary, but not incentive compensation payments. Therefore, each year the Organization and Compensation Committee approves a market-based adjustment to executive base salaries for use in calculating the retirement benefit under the Dominion Resources, Inc. Benefit Restoration Plan (the Restoration Plan). In 1997, this adjustment was 11 percent. Also, the Internal Revenue Code limits the annual retirement benefit that may be paid from a qualified retirement plan and the amount of compensation that may be recognized by the Retirement Plan. To the extent that benefits determined under the Retirement Plan's benefit formula exceed the limitations imposed by the Internal Revenue Code, they will be paid under the Dominion Resources, Inc. Benefit Restoration Plan.

The Company also provides an Executive Supplemental Retirement Plan (the Supplemental Plan) to its elected officers designated to participate by the Board of Directors. The Supplemental Plan provides an annual retirement benefit equal to 25 percent of a participant's final compensation (base pay plus annual incentive plan payments). The normal form of benefit is monthly installments for 120 months to a participant with 60 months of service, who (i) retires at or after age 55 from the employ of the Company, (ii) has become permanently disabled, or (iii) dies. The accrued benefit vests proportionately between the time an officer is elected and when he or she reaches age 55 when the benefit is fully vested If a participant dies while employed, the normal form of benefit will be paid to a designated beneficiary. If a participant dies while retired, but before receiving all benefit payments, the remaining installments will be paid to a designated beneficiary. A lump sum payment is available under certain conditions.

Based on 1997 compensation, the estimated annual retirement benefit for each of the executive officers under the Supplemental Plan would be as follows: N. Askew: $167,406; R.E. Rigsby: $104,345; J.P. O'Hanlon: $113,228; L.E. De Simone: $79,139; L.M. Girvin: $73,764.

Retirement Benefit Funding Plan

The Company maintains a Retirement Benefit Funding Plan to provide a means to secure obligations under the Supplemental Plan, the Restoration Plan, and retirement agreements. The Retirement Benefit Funding Plan does not provide any additional benefits; it simply helps secure the funding for these benefit obligations. The amount payable by Virginia Power under the Supplemental Plan, the Restoration Plan and retirement agreements is reduced, on a dollar-for-dollar basis, by the funds available under the Retirement Benefit Funding Plan.

Employment Agreements

The Company has entered into employment continuity agreements (the Agreements) with its key management executives, including, Norman Askew, Robert E. Rigsby, James P. O'Hanlon, Lawrence E. De Simone, and Larry M. Girvin, which provide benefits in the event of a change in control. Each Agreement has a three-year term and thereafter is automatically extended on its anniversary date for an additional year unless notified that the Agreement will not be extended by the Company. If, following a change in control (as defined in the Agreements) of Dominion Resources or the Company, an executive's employment is terminated by the Company without cause, or voluntarily by the executive within sixty days after a material reduction in the executive's compensation, benefits or responsibilities, the Company will be obligated to pay to the executive continued compensation equaling the average base salary and cash incentive bonuses for the thirty-six full month period of employment preceding the change in control or employment termination. In addition, the terminated executive will continue to be entitled to any benefits due under any stock or benefit plans. The Agreements do not alter the compensation and benefits available to an executive whose employment with the Company continues for the full term of the executive's Agreement. The amount of benefits provided under each executive's Agreement will be reduced by any compensation earned by the executive from comparable employment by another employer during the thirty-six months following termination of employment with the Company. An executive shall not be entitled to the above benefits in the event termination is for cause.

Compensation of Directors

The non-employee members of the Board receive an annual retainer of $19,000 and a fee of $900 for each Board or committee meeting attended. Committee chairmen receive an additional annual retainer of $3,000. Consistent with the Company's philosophy concerning equity-based compensation for officers, effective in 1998 non-employee directors will also receive an annual retainer in Dominion Resources common stock valued at $19,000. These Directors may elect to defer their annual retainer and/or their meeting fees under the Deferred Compensation Plan until they retire from the Board or otherwise direct. The deferred fees are credited, for bookkeeping purposes, with earnings and losses as if they were invested in either an interest bearing account or Dominion Resources Common Stock, depending on the Director's election.

Directors Charitable Contribution Program

Dominion Resources administers a Directors' Charitable Contribution Program (the Program) that covers Directors of the Company, as part of its overall program of charitable giving. Beginning at the death of a Director a donation in an aggregate amount of $50,000 per year for 10 years will be made to one or more qualifying charitable organizations recommended by the individual Director. Life insurance policies have been purchased on the lives of the Directors in connection with the Program. These policies are owned by Dominion Resources, which is also the beneficiary. The Directors derive no financial or tax benefits from the Program.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The table below sets forth as of February 20, 1998, except as noted, the number of shares of Common Stock of Dominion Resources owned by Directors and four other more highly compensated executive officers of Virginia Electric and Power Company.

Name	Shares of Common Stock Beneficially Owned	Director Plan Accounts(1)
John B. Adams, Jr.	3,891	9,091
John B. Bernhardt	1,500	9,091
James F. Betts	7,500	9,091
Thos. E. Capps	44,914(2)	
Jean E. Clary	116	9,162
John W. Harris	500	9,091
Benjamin J. Lambert, III	90	10,212
Richard L. Leatherwood	1,000	17,616
Harvey L. Lindsay	400	9,091
Kenneth A. Randall	3,027	9,091
William T. Roos	14,603(3)	9,091
Frank S. Royal		10,430
Judith B. Sack	1,000	14,575
S. Dallas Simmons	650	13,370
Robert H. Spilman	1,187	9,091
William G. Thomas	1,000	13,257
David A. Wollard		9,879
Norman Askew	1,290(2)	
Lawrence E. De Simone	92	
Larry M. Girvin	7,654	
James P. O'Hanlon	11,100	
Robert E. Rigsby	22,079	
All Directors and Executive Officers as a group — 41 persons (4)	397,599(2)(5)	

(1) Amounts in this column represent share equivalents accumulated under the non-employee director Stock Accumulation Plan. Balances of 9,091 shares are the amounts accumulated thus far under the plan. Because of the plan's vesting provisions, these amounts will not necessarily be distributed to a director. Any balance in excess of 9,091 is an amount of shares accumulated at the director's election under the Deferred Cash Compensation plan. That excess amount will be distributed in actual shares to the director.

(2) Amounts include restricted stock as follows: Mr. Capps — 23,984 shares; Mr. Askew — 1,290; and all directors and executive officers as a group — 89,859.

(3) Mr. Roos disclaims beneficial ownership of 4,387 shares that are held in trusts for family members.

(4) All current directors and executive officers as a group own less than one percent of the number of shares outstanding as of February 20, 1998.

(5) Beneficial ownership is disclaimed for a total of 4,786 shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Hazel & Thomas, a professional corporation, from time to time acts as counsel to the Company. Mr. Thomas, a Director of the Company, is a shareholder of Hazel & Thomas.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this Form 10-K:

1. Financial Statements

See Index on page 21.

2. Exhibits

3.1	—	Restated Articles of Incorporation, as amended, as in effect on September 12, 1994 (Exhibit 3(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference).
3.2	—	Bylaws, as amended, as in effect on October 17, 1997 (Exhibit 3(ii), Form 10-Q for the period ended September 30, 1997, File No. 1-2255, incorporated by reference).
4.1	—	See Exhibit 3 (i) above.
4.2	—	Indenture of Mortgage of the Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Fifty-Ninth Supplemental Indenture (Exhibit 4(ii), Form 10-Q for the quarter ended March 31, 1986, File No. 1-2255, incorporated by reference); Sixtieth Supplemental Indenture (Exhibit 4(ii), Form 10-Q for the quarter ended September 30, 1986, File No. 1-2255, incorporated by reference); Sixty-First Supplemental Indenture (Exhibit 4(ii), Form 8-K, dated June 2, 1987, File No. 1-2255, incorporated by reference); Sixty-Second Supplemental Indenture (Exhibit 4(i), Form 8-K, dated November 3, 1987, File No. 1-2255, incorporated by reference); Sixty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 8, 1988, File No. 1-2255, incorporated by reference); Sixty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 8, 1989, File No. 1-2255, incorporated by reference); Sixty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 22, 1989, File No. 1-2255, incorporated by reference); Sixty-Sixth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 27, 1990, File No. 1-2255, incorporated by reference); Sixty-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 2, 1991, File No. 1-2255, incorporated by reference); Sixty-Eighth Supplemental Indenture (Exhibit 4(i)), Sixty-Ninth Supplemental Indenture (Exhibit 4(ii)) and Seventieth Supplemental Indenture (Exhibit 4(iii), Form 8-K, dated February 25, 1992, File No. 1-2255, incorporated by reference); Seventy-First Supplemental Indenture (Exhibit 4(i)) and Seventy-Second Supplemental Indenture (Exhibit 4(ii), Form 8-K, dated July 7, 1992, File No. 1-2255, incorporated by reference); Seventy-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 6, 1992, File No. 1-2255, incorporated by reference); Seventy-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 6, 1993, File No. 1-2255, incorporated by reference); Seventy-Sixth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 21, 1993, File No. 1-2255, incorporated by reference); Seventy-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 8, 1993, File No. 1-2255, incorporated by reference); Seventy-Eighth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Ninth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Eightieth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 12, 1993, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Eighty-Second Supplemental Indenture (Exhibit 4(i), Form 8-K, dated January 18, 1994, File No. 1-2255, incorporated by reference); Eighty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference); Eighty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated March 22, 1995, File No. 1-2255, incorporated by reference; and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, File No. 1-2255, incorporated by reference).

4.3	—	Indenture, dated April 1, 1985, between Virginia Electric and Power Company and Crestar Bank (formerly United Virginia Bank) (Exhibit 4(iv), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.4	—	Indenture, dated as of June 1, 1986, between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank) (Exhibit 4(v), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.5	—	Indenture, dated April 1, 1988, between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank), as supplemented and modified by a First Supplemental Indenture, dated August 1, 1989, (Exhibit 4(vi), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.6	—	Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, as supplemented (Exhibit 4(a), Form S-3 Registration Statement File No. 333-20561 as filed on January 28, 1997, incorporated by reference).
4.7	—	Virginia Electric and Power Company agrees to furnish to the Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized thereunder does not exceed 10 percent of Virginia Electric and Power Company's total assets.
10.1	—	Operating Agreement, dated June 17, 1981, between Virginia Electric and Power Company and Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and Allegheny Generating Company (Exhibit 10(vi), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.2	—	Purchase, Construction and Ownership Agreement, dated as of December 28, 1982 but amended and restated on October 17, 1983, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(viii), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.3	—	Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (filed herewith).
10.4	—	Nuclear Fuel Agreement, dated as of December 28, 1982 as amended and restated on October 17, 1983, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(x), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.5	—	Credit Agreements dated June 7, 1996, between The Chase Manhattan Bank (formerly Chemical Bank) and Virginia Electric and Power Company (Exhibits 10(i) and 10(ii), Form 10-Q for the period ended June 30, 1996, File No. 1-2255, incorporated by reference).
10.6	—	Credit Agreement, dated December 1, 1985, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xix), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-8489, incorporated by reference).
10.7	—	Agreement for Northern Virginia Services, dated as of November 1, 1985, between Potomac Electric Power Company and Virginia Electric and Power Company (Exhibit 10(xxi), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-8489, incorporated by reference).
10.8	—	Purchase, Construction and Ownership Agreement, dated May 31, 1990, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xi), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.9	—	Operating Agreement, dated May 31, 1990, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.10	—	Coal-Fired Unit Turnkey Contract (Volume 1), dated April 6, 1989, and the Unit 2 Amendment (Volume 1), dated May 31, 1990 between Virginia Electric and Power Company and Old Dominion Electric Cooperative, Westinghouse, Black & Veatch, Combustion Engineering and H. B. Zachry (Volumes 2-11 contain technical specifications) (Exhibit 10(xiii), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.11*	—	Description of arrangements with certain officers regarding additional credited years of service for retirement purposes (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1992, File No. 1-2255, incorporated by reference).

10.12*	—	Dominion Resources, Inc. Directors' Deferred Compensation Plan effective July 1, 1986, as amended and restated on January 1, 1996 (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.13*	—	Dominion Resources, Inc. Performance Achievement Plan, effective January 1, 1986, as amended and restated effective February 19, 1988 (Exhibit 10(xxiii), Form 10-K for the fiscal year ended December 31, 1994, File No. 1-2255, incorporated by reference).
10.14*	—	Dominion Resources, Inc. Executive Supplemental Retirement Plan, effective January 1, 1981 as amended and restated September 1, 1996 with first amendment dated June 20, 1997 and second amendment dated March 3, 1998 (filed herewith).
10.15*	—	Dominion Resources, Inc.'s Cash Incentive Plan as adopted December 20, 1991 (Exhibit 10(xxv), Form 10-K for the fiscal year ended December 31, 1994, File No. 1-2255, incorporated by reference).
10.16*	—	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (filed herewith).
10.17*	—	Dominion Resources, Inc. Retirement Benefit Restoration Plan as adopted effective January 1, 1991 as amended and restated September 1, 1996 (filed herewith).
10.18*	—	Dominion Resources, Inc. Executives' Deferred Compensation Plan, effective January 1, 1994, as amended and restated on January 1, 1997 (Exhibit 10(xix), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.19*	—	Form of an Employment Agreement dated June 23, 1994 between Virginia Power and certain executive officers (Exhibit 10(xxi), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.20*	—	Employment Agreement dated September 15, 1995 between Virginia Power and Robert E. Rigsby (Exhibit 10(xxii), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.21*	—	Employment Agreement dated February 21, 1997 between Dominion Resources and Norman Askew (filed herewith).
10.22*	—	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, effective April 23, 1996 (Exhibit 10(xxiv), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.23*	—	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997 (filed herewith)
23.1	—	Consent of Hunton & Williams (filed herewith).
23.2	—	Consent of Jackson & Kelly (filed herewith).
23.3	—	Consent of Deloitte & Touche LLP (filed herewith).
27	—	Financial Data Schedule (filed herewith).

---

* Indicates management contract or compensatory plan or arrangement

(b) Reports on Form 8-K

None

SIGNATURES

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

VIRGINIA ELECTRIC AND POWER COMPANY

Date: March 20, 1998

By THOS. E. CAPPS
(Thos. E. Capps, Chairman of the Board of Directors)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 20, 1998.

Signature	Title
THOS E. CAPPS **Thos E. Capps**	Chairman of the Board of Directors and Director
JOHN B. ADAMS, JR. **John B. Adams, Jr.**	Director
NORMAN ASKEW **Norman Askew**	President (Chief Executive Officer) and Director
JOHN B. BERNHARDT **John B. Bernhardt**	Director
JAMES F. BETTS **James F. Betts**	Director
JEAN E. CLARY **Jean E. Clary**	Director
JOHN W. HARRIS **John W. Harris**	Director
BENJAMIN J. LAMBERT, III **Benjamin J. Lambert, III**	Director
RICHARD L. LEATHERWOOD **Richard L. Leatherwood**	Director
HARVEY L. LINDSAY, JR. **Harvey L. Lindsay, Jr.**	Director

Signature	Title
Kenneth A. Randall	Director
WILLIAM T. ROOS William T. Roos	Director
FRANK S. ROYAL Frank S. Royal	Director
JUDITH B. SACK Judith B. Sack	Director
S. DALLAS SIMMONS S. Dallas Simmons	Director
ROBERT H. SPILMAN Robert H. Spilman	Director
WILLIAM G. THOMAS William G. Thomas	Director
David A. Wollard	Director
M. S. BOLTON, JR. M. S. Bolton, Jr.	Controller (Principal Accounting Officer)

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1997

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 1-2255

VIRGINIA ELECTRIC AND POWER COMPANY

(Exact name of registrant as specified in its charter)

VIRGINIA	**54-0418825**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification no.)*
701 East Cary Street **Richmond, Virginia**	**23219-3932**
(Address of principal executive offices)	*(Zip Code)*

(804) 771-3000
(Registrant's telephone number, including area code)

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 liquidation value: $5.00 dividend	New York Stock Exchange
Trust Preferred Securities $25 liquidation value: 8.05% dividend	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

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 ☒ 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. ☐

The aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 1998, was zero.

As of February 28, 1998, there were issued and outstanding 171,484 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

VIRGINIA ELECTRIC AND POWER COMPANY

PART I

ITEM 1. BUSINESS
THE COMPANY

Virginia Electric and Power Company is a Virginia Corporation. Our principal office is at 701 East Cary Street, Richmond, Virginia 23219-3932, telephone (804) 771-3000. We are a wholly owned subsidiary of Dominion Resources, Inc. (Dominion Resources), a Virginia corporation. Dominion Resources owns all of our common stock.

Virginia Electric and Power Company is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy within a 30,000 square-mile area in Virginia and northeastern North Carolina. It transacts business under the name Virginia Power in Virginia and under the name North Carolina Power in North Carolina. We have retail customers (including governmental agencies) and wholesale customers such as rural electric cooperatives, power marketers and municipalities. We serve more than 80 percent of Virginia's population. The Company has certificates of convenience and necessity from the State Corporation Commission of Virginia (the Virginia Commission) for service in all territories served at retail in Virginia. The North Carolina Utilities Commission (the North Carolina Commission) has assigned territory to the Company for substantially all of its retail service outside certain municipalities in North Carolina.

The electric utility industry in the United States is undergoing an evolutionary change toward less regulation and more competition. To meet the challenges of this new competitive environment, Virginia Power has developed a broad array of "non-traditional" product and service offerings from its operating business units and subsidiaries:

- Energy Services — offering electric energy and capacity in the emerging wholesale market as well as natural gas and other energy-related products and services;
- Fossil & Hydro — targeting process type industries, such as chemical, paper, plastics and petroleum to become a service provider of instrumentation equipment;
- Nuclear Services — offering management and operations services to other electric utilities;
- Commercial Operations — providing power distribution related services, including transmission and distribution, engineering and metering services to other gas, water and electric utilities; and
- Telecommunications — offering telecommunications services through the Company's existing fiber-optic network.

The Company and its subsidiaries had 9,043 full-time employees on December 31, 1997. A total of 3,452 of our employees are represented by the International Brotherhood of Electrical Workers under a contract extending to March 31, 1998. The Company and the union have tentatively agreed, subject to ratification by the union membership, to a two year extension of the contract.

For a more thorough review of the changing utility industry and the Company's strategy see COMPETITION AND STRATEGIC INITIATIVES below and Future Issues — *Competition* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A).

COMPANY MANAGEMENT

In April, Dr. James T. Rhodes, President and Chief Executive Officer since 1989, announced his retirement effective August 1, 1997. The Board of Directors subsequently elected Mr. Norman Askew as the new President and Chief Executive Officer, effective August 1, 1997. Mr. Askew was previously the Chief Executive of East Midlands Electricity plc, a United Kingdom regional electricity company acquired by Dominion Resources during the first quarter of 1997. Mr. Askew also replaced Dr. Rhodes on the Board of Directors effective August 1, 1997.

COMPETITION AND STRATEGIC INITIATIVES

A number of developments in the United States are causing a trend toward less regulation and more competition in the electric utility industry. This is evidenced by legislative and regulatory action at both the federal and state levels. To the extent that competition is either authorized or mandated and regulation is eliminated or relaxed, electric utilities may no longer be guaranteed an opportunity to recover all of their prudently incurred costs, and utilities with costs that exceed the market prices established by the competitive market will run the risk of suffering losses, which may be substantial.

Virginia Power has responded to these trends by undertaking cost-cutting measures, engaging in re-engineering efforts, restructuring its core business processes, and pursuing a strategic planning initiative to encourage innovative approaches to serving traditional markets. The Company has established separate business units, as discussed above, to fully execute these strategies.

The Company also is vigorously participating in the state and federal legislative actions currently underway to bring about competition in the electric utility industry, in an effort to ensure an orderly transition from a regulated environment.

The Company's non-traditional businesses face competition from a variety of utility and non-utility entities.

For a full discussion of the regulatory and legislative issues related to competition, carefully read the Future Issues section of MD&A.

REGULATION

General

In a wide variety of matters in addition to rates, Virginia Power is presently subject to regulation by the Virginia Commission and the North Carolina Commission, the Environmental Protection Agency (EPA), Department of Energy (DOE), Nuclear Regulatory Commission (NRC), the Federal Energy Regulatory Commission (FERC), the Army Corps of Engineers, and other federal, state and local authorities. Compliance with numerous laws and regulations increases the Company's operating and capital costs by requiring, among other things, changes in the design and operation of existing facilities and changes or delays in the location, design, construction and operation of new facilities. The commissions regulating the Company's rates have historically permitted recovery of such costs.

Virginia Power 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 governmental agencies. Such approvals relate to, among other things, the environmental impact of such activities, the relationship of such activities to the need for providing adequate utility service and the design and operation of proposed facilities.

Both federal and state legislative bodies have been studying competition and restructuring in the electric utility industry. Please carefully read the full discussion of this matter found in the Future Issues — *Competition — Legislative Initiatives* section of MD&A.

Virginia

In 1995, the Virginia Commission instituted an ongoing generic investigation on electric industry restructuring, resulting in a number of reports by its Staff covering such issues as retail wheeling experiments and the status of wholesale power markets. The Staff also submitted a report to the General Assembly calling for a cautious, two-phase, five-year period to address restructuring issues. The report acknowledged the need for direction from the Virginia legislature concerning policy issues surrounding competition in the electric industry.

In November 1996, the Virginia Commission instituted a proceeding concerning Virginia Power's cost of service and possible restructuring of the electric utility industry as it might relate to Virginia Power. On March 24, 1997, Virginia Power filed in that proceeding a calculation of its cost of service for 1996 and a proposed Alternative Regulatory Plan (ARP). Subsequently, the Commission consolidated this proceeding with the proceeding concerning the Company's 1995 Annual Informational Filing, in which the Company's base rates were made interim and subject to refund as of March 1, 1997. Please carefully read the Future Issues — *Competition — Legislative and Regulatory Initiatives* sections of MD&A and RATES-Virginia, below for details concerning the ARP, its current status and related legislative developments.

In December 1995, Virginia Power applied to the Virginia Commission for approval of arrangements with Chesapeake Paper Products Company (CPPC), under which Virginia Power would facilitate the design, construction and financing of a cogeneration plant to meet CPPC's energy requirements for its industrial processes at its plant in West Point, Virginia. On August 13, 1997, the Virginia Commission approved, in substantial part, the proposed transactions between Virginia Power and CPPC's successor in ownership, St. Laurent Paper Products Co. St. Laurent later determined that the current design of the facility was no longer compatible with its long-term business strategies and terminated its contractual arrangement with Virginia Power. The Virginia Commission dismissed the proceeding on January 15, 1998.

In June 1997, the Virginia Commission granted the Company's request to implement a monitoring program that requires certain non-utility generators to provide certain information sufficient to determine continued compliance with the "Qualifying Facility" (QF) requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA).

On August 8, 1997, the Virginia Commission granted the Company's request to provide interchange telecommunications services and approved the proposed affiliate agreements between Virginia Power and our wholly-owned subsidiary, VPS Communications, Inc. (VPSC). Under the authority granted, VPSC will provide a range of telecommunications services, including private line and special access services and high-capacity fiberoptic services.

On September 3, 1997, the Virginia Commission granted the Company's request to provide services to our wholly-owned subsidiary, Virginia Power Services, Inc. (VPS), which would enable Virginia Power Nuclear Services Company (VPN), a VPS subsidiary, to furnish nuclear management and operation services to electric utilities seeking assistance in the management and operation of their nuclear generating facilities. VPN currently provides such services to Northeast Utilities at its Millstone Unit 2 nuclear plant.

FERC

In April 1996, FERC issued final rules in Order Nos. 888 and 889 addressing open access transmission service, stranded costs, standards of conduct and open access same-time information systems (OASIS). In July 1996, Virginia Power filed an open access transmission service tariff in compliance with FERC's Order No. 888. In compliance with FERC's directive, Virginia Power's OASIS became operational on January 3, 1997. Also, on that date the standards of conduct requiring separation of transmission operations/reliability functions from wholesale merchant/marketing functions became effective. The Company also made filings to comply with FERC's directive that, effective January 1, 1997, utilities could no longer make bundled sales of transmission and generation services in economy energy transactions. In certain of those filings, Virginia Power canceled or committed not to use the economy energy rate schedules contained in interconnection agreements with neighboring utilities. On March 4, 1997, FERC issued Order Nos. 888-A and 889-A, which addressed requests for rehearing of Order Nos. 888 and 889. Orders No. 888-A and 889-A essentially reaffirm the basic principles of 888 and 889 and clarify and make limited modifications to those orders. On December 17, 1997, FERC issued Order Nos. 888-B and 889-B. FERC rejected all requests for rehearing filed with respect to Order Nos. 888-A and 889-A and clarified and made limited modifications to those orders. Several parties have appealed the 888 orders to the United States Court of Appeals for the District of Columbia Circuit.

For a discussion of the status of the Company's Open Access Transmission Tariff filing, see RATES — FERC below.

For additional discussion of open access issues see Future Issues — *Competition* under MD&A.

LG&E Westmoreland Southampton owns a cogeneration facility in Franklin, Virginia, and sells its output to Virginia Power. Southampton has sought a waiver of FERC operating requirements for Qualifying Facilities (QF's) under PURPA, however FERC refused to grant such a waiver. On March 31, 1997, the United States Court of Appeals for the District of Columbia Circuit granted FERC's motion to dismiss Southampton's Petition for Review.

Environmental

From time to time, Virginia Power may be designated by the EPA as a potentially responsible party (PRP) with respect to a Superfund site. As a result of that designation or other regulations regarding the remediation of waste, we may become obligated to fund remedial investigations or actions. We do not believe that any currently identified sites will result in significant liabilities. For a discussion of the Company's site remediation efforts, see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS.

Permits under the Clean Water Act and state laws have been issued for all of the Company's steam generating stations now in operation. These permits are subject to reissuance and continuing review. The Clean Air Act, as amended in 1990, requires the Company to reduce its emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Beginning in 1995, the SO_2 reduction program is based on the issuance of a limited number of SO_2 emission allowances, each of which may be used as a permit to emit one ton of SO_2 into the atmosphere or may be sold to someone else. The program is administered by the EPA.

For additional information on Environmental Matters, Clean Air Act compliance and related issues see the Future Issues section of MD&A.

Nuclear

All aspects of the operation and maintenance of the Company's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and 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 the Company's nuclear generating units.

In July 1995, the Virginia Commission instituted an investigation regarding spent nuclear fuel disposal. As directed, Virginia Power and others filed comments on legal and public policy issues related to spent nuclear fuel storage and disposal. In February 1996, the Commission Staff filed its Report recommending that adoption of a definitive policy on spent nuclear fuel disposal issues be delayed pending the outcome of litigation against the Department of Energy concerning spent nuclear fuel acceptance, the outcome of proposed federal legislation concerning development of an interim storage facility, and development of a vision of the likely outcome of the electric utility industry's restructuring efforts. The Virginia Commission consolidated the proceeding with Virginia Power's pending fuel cost recovery proceeding in October 1996. On March 20, 1997, the Virginia Commission returned the spent nuclear fuel disposal issue to a separate proceeding.

On January 31, 1997, Virginia Power joined thirty-five other electric utilities in filing a petition in the United States Court of Appeals for the District of Columbia Circuit, seeking to compel DOE to comply with its obligation to begin accepting the utilities' spent nuclear fuel for disposal by January 31, 1998, the date imposed by the Nuclear Waste Policy Act. Additional utilities have joined since the original filing. On November 14, 1997, the Court issued an Order finding that DOE's obligation to begin accepting spent nuclear fuel by the deadline is unconditional, and that DOE may not excuse its delay on the grounds that it has not prepared a permanent repository or interim storage facility. The Court found that DOE's spent fuel disposal contracts with the utilities offer a potentially adequate remedy for DOE's failure to meet its obligation. DOE filed a petition for rehearing on December 29, 1997.

RATES

The Company's electric services sales were subject to rate regulation in 1997 as follows:

		1997	
		Percent of Revenues	Percent of Kwh Sales
Virginia retail:			
Non-Governmental customers	Virginia Commission	81%	76%
Governmental customers	Negotiated Agreements	10	12
North Carolina retail	North Carolina Commission	5	5
Wholesale —Sales for Resale*	FERC	4	7
		100%	100%

* Excludes wholesale power marketing sales subject to FERC regulation.

Substantially all of the Company's electric service sales are subject to recovery of changes in fuel costs either through fuel adjustment factors or periodic adjustments to base rates, each of which requires prior regulatory approval.

Each of these jurisdictions has the authority to disallow recovery of costs it determines to be excessive or imprudently incurred. Various cost items may be reviewed on occasion, including costs of constructing or modifying facilities, on-going purchases of capacity or providing replacement power during generating unit outages.

FERC

In compliance with FERC's Order No. 888, Virginia Power filed an open access transmission service tariff, which became effective on July 9, 1996. In October 1996, FERC issued a procedural order, scheduling a hearing for April 28, 1997. The Company and all parties reached a settlement of issues raised in the proceeding, and on March 20, 1997, those parties jointly filed with FERC the Settlement Agreement and Motion to Certify the Settlement Agreement. On April 23, 1997 the presiding Administrative Law Judge certified the Settlement Agreement to the FERC and on June 11, 1997, the FERC approved the settlement.

In compliance with FERC's Order No. 889, on January 3, 1997, the Company filed its Procedures For Standards of Conduct for Unbundled Transmissions and Wholesale Merchant Function (Standards of Conduct) effective on that date. On July 1, 1997, the Company filed an amendment to the Standards of Conduct in Compliance with FERC's Order No. 889-A.

On July 16, 1997, the Company filed another amendment in response to a FERC Staff request. The Company is awaiting FERC action on the filing.

On September 11, 1997, FERC authorized the Company to sell power at market-based rates but set for hearing the issue of the impact of any transmission constraints on Virginia Power's ability to exercise generation market power in localized areas within its service territory. If FERC finds that transmission constraints give Virginia Power generation dominance, it could either revoke or limit the scope of the market-based rate authority. The hearing is scheduled to commence June 2, 1998.

On October 31, 1997, Virginia Power filed at FERC three agreements with Old Dominion Electric Cooperative (ODEC) to amend the parties' Interconnection and Operating Agreement (I&O Agreement) and to unbundle transmission services provided to ODEC under the I&O Agreement. On December 22, 1997, FERC issued a deficiency letter with respect to the filing directing the Company to provide additional information. On January 21, 1998, the Company provided the requested information. FERC accepted the agreements on March 12, 1998.

Virginia

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. Virginia Power filed its Alternative Regulatory Plan in March 1997, based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

In July 1996, Virginia Power proposed to substantially reduce the rates paid under Schedule 19 to cogenerators and small power producers of 100 kW or less. The rates became effective on an interim basis on January 1, 1997. On January 21, 1998, the Virginia Commission approved revised Schedule 19 rates. The approved rates do not differ in any significant way from the rates originally proposed by the Company.

In October 1996, Virginia Power filed an application with the Virginia Commission to increase its fuel factor from 1.299 cents per kWh to 1.322 cents per kWh, reflecting a fuel factor annual revenue increase of approximately $48.2 million. The increase became effective on an interim basis on December 1, 1996. On June 11, 1997, the Commission entered an Order Establishing Fuel Factor approving the requested increase.

On October 31, 1997, Virginia Power filed with the Virginia Commission its application for a reduction of $45.6 million in its fuel cost recovery factor for the period December 1, 1997 through November 30, 1998. The reduction became effective on an interim basis on December 1, 1997. Subsequently, as a result of amendments to two non-utility power purchase contracts, the Company proposed two additional reductions of approximately $30.2 million and $18 million for the same period, bringing the total proposed fuel factor reduction to $93.8 million. Both additional reductions were approved on an interim basis, effective March 1, 1998. A hearing is scheduled for April 9, 1998.

North Carolina

On November 4, 1996, the Company filed for approval of a new Schedule 19 which governs purchases from cogenerators and small power producers. The Company proposed rates substantially lower than those previously specified. It also proposed to reduce the applicability threshold to 100 kW and shorten the maximum term of contracts under Schedule 19 to five years. On June 19, 1997, the North Carolina Commission issued an Order requiring the Company to offer long-term (5-,10- and 15-year) levelized capacity payments to hydroelectric and certain landfill and waste facilities contracting for up to 5 MW; a 5-year levelized rate option to other QFs contracting for up to 100 kW; and optional long-term levelized energy payments for QFs rated at 100 kW or less capacity.

On October 10, 1997 the Company filed an application with the North Carolina Commission for a $728,000 increase in fuel revenues. On December 29, 1997, the North Carolina Commission entered an Order Approving Fuel Charge Adjustment. The Order approved an approximate $600,000 increase in the annual rates and charges paid by the retail customers of North Carolina Power effective on January 1, 1998.

CAPITAL REQUIREMENTS AND FINANCING PROGRAM

Construction and Nuclear Fuel Expenditures

Virginia Power's estimated construction and nuclear fuel expenditures for the three-year period 1998-2000, total $1.5 billion. It has adopted a 1998 budget for construction and nuclear fuel expenditures as set forth below:

	Estimated 1998 Expenditures (millions)
Production	$ 60
Technology	150
General Support Facilities	19
Transmission	37
Distribution	213
Nuclear Fuel	86
Total Construction Requirements and Nuclear Fuel Expenditures	$565

In addition, the Company expects to incur approximately $23 million of expenditures in 1998 in connection with the development of energy management projects for customers. Contracts with such customers provide for the recovery of these costs in future years.

Financing Program

The Company currently has three shelf registrations on file with the Securities Exchange Commission (SEC) providing the Company with $915 million of debt capital resources. The Company also has a Preferred Stock shelf registered with the SEC for $100 million in aggregate principal amount, which has not been utilized.

The Company intends to issue securities from time to time to meet its capital requirements, which include $333.5 million of long-term debt maturities in 1998.

Please see the Liquidity and Capital Resources section of MD&A for details about our Financing Program.

SOURCES OF POWER

Company Generating Units

Name of Station, Units and Location	Years Installed	Type of Fuel	Summer Capability MW
Nuclear:			
Surry Units 1 & 2, Surry, Va	1972-73	Nuclear	1,602
North Anna Units 1 & 2, Mineral, Va	1978-80	Nuclear	1,790(a)
Total nuclear stations			3,392
Fossil Fuel:			
Steam:			
Bremo Units 3 & 4, Bremo Bluff, Va.	1950-58	Coal	227
Chesterfield Units 3-6, Chester, Va.	1952-69	Coal	1,250
Clover Units 1 & 2, Clover, Va.	1995-96	Coal	882(b)
Mt. Storm Units 1-3, Mt. Storm, W. Va.	1965-73	Coal	1,587
Chesapeake Units 1-4, Chesapeake, Va.	1953-62	Coal	595
Possum Point Units 3 & 4, Dumfries, Va.	1955-62	Coal	322
Yorktown Units 1 & 2, Yorktown, Va.	1957-59	Coal	326
Possum Point Units 1, 2, & 5, Dumfries, Va.	1948-75	Oil	929
Yorktown Unit 3, Yorktown, Va.	1974	Oil & Gas	818
North Branch Unit 1, Bayard, W. Va.	1994	Waste Coal	74(c)
Combustion Turbines:			
35 units (8 locations)	1967-90	Oil & Gas	1,019
Combined Cycle:			
Bellmeade, Richmond, Va.	1991	Oil & Gas	230
Chesterfield Units 7 & 8, Chester, Va.	1990-92	Oil & Gas	397
Total fossil stations			8,656
Hydroelectric:			
Gaston Units 1-4, Roanoke Rapids, N.C.	1963	Conventional	225
Roanoke Rapids Units 1-4, Roanoke Rapids, N.C.	1955	Conventional	99
Other	1930-87	Conventional	3
Bath County Units 1-6, Warm Springs, Va.	1985	Pumped Storage	1,260(d)
Total hydro stations			1,587
Total Company generating unit capability			13,635
Net Purchases			1,480
Non-Utility Generation			3,277
Total Capability			18,392

(a) Includes an undivided interest of 11.6 percent (208 MW) owned by ODEC.

(b) Includes an undivided interest of 50 percent (441 MW) owned by ODEC.

(c) Effective January 25, 1996, this unit was placed in a cold reserve status.

(d) Reflects the Company's 60 percent undivided ownership interest in the 2,100 MW station. A 40 percent undivided interest in the facility is owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc (AE).

The Company's highest one-hour integrated service area summer peak demand was 14,537 MW on July 28, 1997, and an all-time high one-hour integrated winter peak demand of 14,910 MW was reached on February 5, 1996.

SOURCES OF ENERGY USED AND FUEL COSTS

For information as to energy supply mix and the average fuel cost of energy supply, see Results of Operations under MD&A.

Nuclear Operations and Fuel Supply

In 1997, the Company's four nuclear units achieved a combined capacity factor of 91.1 percent.

The Company utilizes both long-term contracts and spot purchases to support its needs for nuclear fuel. The Company continually evaluates worldwide market conditions in order to ensure a range of supply options at reasonable prices. Current agreements, inventories and spot market availability will support the Company's current and planned fuel supply needs for fuel cycles throughout the remainder of the 1990's and into the early 2000's. Beyond that period, additional fuel will be purchased as required to ensure optimum cost and inventory levels.

The DOE is not expected to begin the acceptance of spent fuel in 1998 as specified in the Company's contract with the DOE. However, on-site spent nuclear fuel storage at the Surry Power Station (spent fuel pool and dry cask storage) is expected to be adequate for the Company's needs until the DOE begins accepting spent fuel. The North Anna Power Station will require additional spent fuel storage capacity in 1998. The Company submitted a license application to the NRC in May 1995 for a dry cask facility at North Anna. The Company anticipates that this application will be approved in mid-1998.

For details on the issues of decommissioning and nuclear insurance, see Note C to the CONSOLIDATED FINANCIAL STATEMENTS.

Fossil Operations and Fuel Supply

The Company's fossil fuel mix consists of coal, oil and natural gas. In 1997, Virginia Power consumed approximately 13 million tons of coal. As with nuclear fuel, the Company utilizes both long-term contracts and spot purchases to support its needs. The Company presently anticipates that sufficient coal supplies at reasonable prices will be available for the remainder of the 1990's. Current projections for an adequate supply of oil remain favorable, barring unusual international events or extreme weather conditions which could affect both price and supply.

The Company uses natural gas as needed throughout the year for two combined cycle units and at several combustion turbine units. For winter usage at the combined cycle sites, gas is purchased and stored during the summer and fall and consumed during the colder months when gas supplies are not available at favorable prices. The Company has firm transportation contracts for the delivery of gas to the combined cycle units. Current projections indicate gas supplies will be available for the next several years.

Purchases and Sales of Energy

Virginia Power relies on purchases of power to meet a portion of its capacity requirements. The Company also makes economy purchases of power from other utility systems when it is available at a cost lower than the Company's own generation costs.

Under contracts effective January 1, 1985, Virginia Power agreed to purchase 400 MW of electricity annually through 1999 from Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier), and agreed to purchase 500 MW of electricity annually during 1987-99 from certain operating units of American Electric Power Company, Inc. (AEP).

The Company has a diversity exchange agreement with AE under which AE delivers 200 MW to Virginia Power in the summer and Virginia Power delivers 200 MW to AE in the winter.

Virginia Power also has 57 non-utility power purchase contracts with a combined dependable summer capacity of 3,277 MW (for information on the financial obligations under these agreements see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS). In a continuing effort to mitigate its exposure to above-market long-term purchased power contracts, the Company is evaluating its long-term purchased power contracts and negotiating modifications to their terms, including cancellations, where it is determined to be economically advantageous to do so.

The Company's wholesale power group actively participates in the purchase and sale of wholesale electric power and natural gas in the open market. The wholesale power group has expanded the Company's trading range beyond the geographic limits of the Virginia Power service territory, and has developed trading relationships with energy buyers and sellers on a nationwide basis.

In July 1997, the Company executed three agreements with Old Dominion Electric Cooperative (ODEC) which provide for the amendment of the parties' Interconnection and Operating Agreement (I&O Agreement). The first agreement provides for the transition from cost-based rates for capacity and energy purchases by ODEC to market-based rates by 2002. The second two agreements are the Service and Operating Agreements for Network Integration Transmission Service, which unbundled the transmission services provided to ODEC under the I&O Agreement.

FUTURE SOURCES OF POWER

As reported earlier, both the Hoosier 400 MW long-term purchase and the AEP 500 MW long-term purchase will expire on December 31, 1999. The Company presently anticipates adding peaking capacity beginning in the year 2000 to meet its anticipated load growth. The Company has and will pursue capacity acquisition plans to provide that capacity and maintain a high degree of service reliability. This capacity may be owned and operated by others and sold to the Company or may be built by the Company if it determines it can build capacity at a lower overall cost. The Company also pursues conservation and demand-side management (see CONSERVATION AND LOAD MANAGEMENT below). No Company-owned generation is currently in the planning or construction stages.

For additional information, see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS.

CONSERVATION AND LOAD MANAGEMENT

The Company is committed to evaluating and selecting demand-side and supply-side options on a consistent basis in order to provide reliable, low-cost service to its customers. Conservation and load management programs are evaluated annually at Virginia Power through a resource planning process that directly compares the stream of costs and benefits from supply-side and demand-side options. This process supports a conservation and load management portfolio which contributes both to the selection of low-cost resources to meet the future electricity needs of the Company's customers, as well as the efficient use of current resources.

Events in the evolving electric power marketplace and its regulatory and legislative environment continue to impact utility-sponsored conservation and load management programs. In the future, the Company anticipates a greater reliance on the use of price signals to convey information to our customers regarding energy-related costs, resulting in more efficient purchase decisions.

INTERCONNECTIONS

The Company maintains major interconnections with Carolina Power and Light Company, AEP, AE and the utilities in the Pennsylvania-New Jersey-Maryland Power Pool. Through this major transmission network, the Company has arrangements with these utilities for coordinated planning, operation, emergency assistance and exchanges of capacity and energy.

In December 1996, the Company joined with Allegheny Power Service Corporation, Cleveland Electric Illuminating Company, Toledo Edison Company, Ohio Edison Company, Pennsylvania Power Company and Southern Company Services, Inc. (the Transmission Alliance) to file a contract with the FERC entitled the GAPP Experiment Participation Agreement (GAPP Agreement). The Transmission Alliance and the GAPP Agreement were established to promote fair and equitable use of the transmission systems based on the General Agreement on Parallel Paths (GAPP) model for coordinating the flow of bulk supplies of electricity among utilities. GAPP principles allow electric companies to determine where electricity actually flows in bulk power transactions, as opposed to the "contract" paths that are based on power purchase and transmission agreements among buying, selling and transmitting utilities.

Compensation for transmission services has historically been based on contract paths. The GAPP Agreement was designed to determine the physical path electricity actually takes through the system and allocate open access transmission revenues among the parties. The GAPP Agreement was designed as an experiment to test the GAPP methods and procedures for a period of two years. The FERC accepted the contract on March 25, 1997. The Company and the Transmission Alliance implemented the GAPP Agreement on April 2, 1997.

On November 14, 1997, in accordance with the FERC order accepting the GAPP Agreement, the Transmission Alliance issued a report detailing the results of the first six months of the experiment. The preliminary results of the experiment indicate that it is technically possible to monitor and predict the physical flow of electricity over multiple systems and that transmission revenues reallocated according to actual use of the system differ significantly from collections under a contract path approach. In October 1997, Virginia Power gave notice to the Transmission Alliance that, effective January 1, 1998, it was exercising its option under the GAPP Agreement to terminate its involvement in the experiment.

On December 9, 1997, the Company, the Transmission Alliance and other utilities agreed to study the creation of an independent regional transmission entity. The memorandum of understanding to initiate this study was signed by eleven investor-owned electric companies, including Virginia Power, Consumers Energy, Detroit Edison, Duquesne Light Company, The Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, Toledo Edison Company, and the Allegheny Energy Companies (Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company). This group is an outgrowth of the GAPP Agreement and its key goals are to maintain the long-term reliability and security of the utilities' interconnected transmission systems; ensure the most efficient use of resources; eliminate pancaking of rates within and between transmission entities; avoid duplication of costs and achieve transmission cost savings; and, strike an appropriate balance among the diverse interests of energy suppliers, customers, and shareholders. The group will also explore cooperative agreements designed to achieve these goals while ensuring nondiscriminatory and comparable access to all users of the group's transmission system. The companies intend to be responsive to industry changes, especially with the introduction of retail competition in some of the areas served by the signatories and as some other industry participants consider creation of independent transmission operating companies or separate transmission companies. Further, the companies will have the flexibility to continue to investigate and pursue other opportunities and arrangements that could develop regarding independent system operators or independent transmission companies.

Virginia Power and Appalachian Power Company (AEP-Virginia), an operating unit of AEP, each sought approval from the SCC in 1991 to construct certain interconnecting transmission facilities. These applications resulted from a joint planning effort of Virginia Power and AEP to meet the requirements of their customers. At the time of Virginia Power's application, particularly during the summer of 1992, constraints were being experienced on transfers of power into the Virginia Power service territory from the west. On November 7, 1997, the SCC issued an Order directing the Company to report to the Commission on the continued need for certain new interconnected transmission facilities, on the relationship between the Company's application to build the new facilities and certain other pending proceedings, and on the Company's construction plans, if the SCC grants the Company's application.

On December 15, 1997, the Company filed a report in compliance with the SCC Order stating that since the filing of the Company's application, the constraints have been less frequent, due in part to less severe summer weather, and actual power requirements have been less than originally forecasted. In addition, generating resources within the Virginia Power service area have been increased by the higher performance level of the nuclear units, as well as the completion of the Clover Station. Completion of the AEP project is a prerequisite for the Virginia Power project to go forward. The proposed Virginia Power project would not fulfill its intended purpose without the AEP line being built. AEP has withdrawn its original application and has instituted a new proceeding before the Commission in which different routing is proposed. Virginia Power continues to monitor closely the progress of AEP in this proceeding with respect to its new proposal, but until more is known about these proceedings, Virginia Power cannot predict what its construction plans will be.

ITEM 2. PROPERTIES

The Company owns its principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of its property is subject to the lien of a mortgage securing its First and Refunding Mortgage Bonds. Right-of-way grants from the apparent owners of real estate have been obtained for most electric lines, but underlying titles have not been examined except for transmission lines of 69 Kv or more. Where rights of way have not been obtained, they could be acquired from private owners by condemnation if necessary. Many electric lines are on publicly owned property, as to which permission for use is generally revocable. Portions of the Company's transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, surplus capacity in the line if any exists.

The Company leases certain buildings and equipment. See Note G to the CONSOLIDATED FINANCIAL STATEMENTS.

See Company Generating Units under SOURCES OF POWER under Item 1. BUSINESS.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the Company is 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 the Company, or permits issued by various local, state and federal agencies for the construction or operation of facilities. From time to time, there may be administrative proceedings on these matters pending. In addition, in the normal course of business, the Company is involved in various legal proceedings. Management believes that the ultimate resolution of these proceedings will not have a material adverse effect on the Company's financial position, liquidity or results of operations.

In December 1995, two civil actions were filed in the Virginia Circuit Court of the City of Norfolk against the City of Norfolk and Virginia Power, one for $15 million and one for $3 million, by property owners who each alleged contamination of their respective properties by hazardous substances originating on nearby property now owned by the city and formerly owned by the Company. In reference to the $15 million action, the parties reached a settlement prior to the scheduled August 18, 1997, trial date. The related action by the other property owner seeking $3 million is still pending, but has not yet been scheduled for trial.

On April 2, 1997, Doswell Limited Partnership (Doswell) filed a motion for judgment against Virginia Power in the Circuit Court of the City of Richmond. Doswell is an independent power producer that has entered into two power purchase agreements with Virginia Power and claims the Company breached one of those agreements. On the same date, Doswell also filed a complaint against Virginia Power in the United States District Court for the Eastern District of Virginia alleging certain claims relating to the two power purchase agreements. In March 1998, the parties agreed that both proceedings should be stayed in order to give the parties an opportunity to negotiate amendments to the power purchase agreements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On October 17, 1997, by Consent of the Sole Shareholder, Dominion Resources, Inc., the number of Virginia Power Directors was expanded to a maximum of eighteen (18) and the following Directors were elected to serve for terms expiring at the annual shareholder meetings for the years indicated below:

John B. Bernhardt	2000
John W. Harris	1998
Kenneth A. Randall	1999
Frank S. Royal	1998
Judith B. Sack	1999
S. Dallas Simmons	2000
David A. Wollard	1999

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All of the Company's Common Stock is owned by Dominion Resources.

The Company paid quarterly cash dividends on its Common Stock as follows:

	1st	2nd	3rd	4th
	(Millions)			
1997	$95.9	$93.4	$94.7	$95.9
1996	$95.3	$96.5	$96.1	$97.9

ITEM 6. SELECTED FINANCIAL DATA

	1997	1996	1995	1994	1993
	(Millions, except percentages)				
Revenues	$ 5,079.0	$ 4,420.9	$ 4,351.9	$ 4,170.8	$ 4,187.3
Income from operations	1,019.3	1,010.0	971.9	957.1	1,070.6
Net income	469.1	457.3	432.8	447.1	509.0
Balance available for Common Stock	433.4	421.8	388.7	404.9	466.9
Total assets	11,953.4	11,828.0	11,827.7	11,647.9	11,520.5
Total net utility plant	9,219.2	9,433.8	9,573.1	9,623.4	9,459.7
Long-term debt, noncurrent capital lease obligations, preferred stock subject to mandatory redemption and preferred securities of subsidiary trust	3,854.4	3,916.2	4,228.0	4,157.5	4,151.1
Utility plant expenditures (including nuclear fuel)	481.8	484.0	577.5	660.9	712.8
Capitalization ratios (percent):					
Debt	45.4	46.4	47.2	46.7	46.4
Preferred stock	7.6	7.5	7.5	9.0	9.2
Preferred securities	1.5	1.5	1.5		
Common equity	45.5	44.6	43.8	44.3	44.4
Embedded cost (percent):					
Long-term debt	7.60	7.68	7.73	7.65	7.67
Preferred stock	5.25	5.14	5.29	5.47	4.88
Preferred securities	8.72	8.72	8.72		
Weighted average	7.29	7.34	7.41	7.29	7.18

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995, including (without limitation) discussions as to expectations, beliefs, plans, objectives and future financial performance, or assumptions underlying or concerning matters discussed in this document. These discussions, and any other discussions, including certain contingency matters (and their respective cautionary statements) discussed elsewhere in this report, that are not historical facts, are forward-looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

Some important factors that could cause actual results or outcomes to differ materially from those discussed in the forward-looking statements include current governmental policies and regulatory actions (including those of FERC, the EPA, the DOE, the NRC, the Virginia Commission and the North Carolina Commission), industry and rate structure, operation of nuclear power facilities, acquisition and disposal of assets and facilities, operation and storage facilities, recovery of the cost of purchased power, nuclear decommissioning costs, and present or prospective wholesale and retail competition. The business and profitability of Virginia Power also are influenced by economic and geographic factors including political and economic risks, changes in and compliance with environmental laws and policies, weather conditions and catastrophic weather-related damage, competition for retail and wholesale customers, pricing and transportation of commodities, market demand for energy, inflation, capital market conditions, unanticipated changes in operating expenses and capital expenditures, competition for new energy development opportunities and legal and administrative proceedings. All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond the control of Virginia Power. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of each such factor on the business of the Company.

Any forward-looking statement speaks only as of the date on which such statement is made, and Virginia Power undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Liquidity and Capital Resources

Operating activities continue to be a strong source of cash flow, providing $1,091 million in 1997 compared to $1,115 million in 1996. The decrease of $24 million (or 2 percent) from the previous year is attributable to normal business fluctuations. Over the past three years, cash flow from operating activities has, on average, covered 134 percent of our total construction requirements and provided 81 percent of our total cash requirements. Our remaining cash needs are met generally with proceeds from the sale of securities and short-term borrowings.

Financing activities have represented a net outflow of cash in recent years as strong cash flow from operations and the absence of major construction programs have reduced the Company's reliance on debt financing.

Cash from (used in) financing activities was as follows:

	1997	1996	1995
		(Millions)	
Issuance of long-term debt	$ 270.0	$ 24.5	$ 240.0
Issuance of preferred securities of subsidiary trust			135.0
Issuance (Repayment) of short-term debt	(86.2)	143.4	169.0
Repayment of long-term debt and preferred stock	(311.3)	(284.1)	(439.0)
Dividend payments	(415.6)	(421.4)	(438.6)
Other	(13.5)	(13.2)	(13.7)
Total	$(556.6)	$(550.8)	$(347.3)

We have taken advantage of declining interest rates by issuing new debt at lower rates as higher-rate debt has matured. For example, in 1997, $311.3 million of the Company's long-term debt securities matured with an average effective rate of 8.08 percent. As a partial replacement for this maturing debt, we issued $270 million of long-term debt securities during the year with an average effective rate of 6.84 percent.

We currently have three shelf registration statements effective with the Securities and Exchange Commission from which we can obtain additional debt capital: $400 million of Junior Subordinated Debentures; $375 million of Debt Securities, including First and Refunding Mortgage Bonds, Senior Notes and Senior Subordinated Notes filed in February 1998; and $200 million of Medium-Term Notes, Series F. The remaining principal amount of debt that can be issued under these registrations totals $915 million. An additional capital resource of $100 million in preferred stock also is registered with the Securities and Exchange Commission.

The Company has a commercial paper program that is supported by two credit facilities totaling $500 million. Proceeds from the sale of commercial paper are primarily used to provide working capital. Net borrowings under the program were $226.2 million at December 31, 1997.

Investing activities in 1997 resulted in a net cash outflow of $546.1 million, primarily due to $397.0 million of construction expenditures and $84.8 million of nuclear fuel expenditures. The construction expenditures included approximately $252.4 million for transmission and distribution projects, $52.1 million for production projects, $49.7 million for information technology projects and $42.8 million for other projects.

Cash used in investing activities was as follows:

	1997	1996 (Millions)	1995
Utility plant expenditures (excluding AFC — other funds)	$(397.0)	$(393.8)	$(519.9)
Nuclear fuel (excluding AFC — other funds)	(84.8)	(90.2)	(57.6)
Nuclear decommissioning contributions	(36.2)	(36.2)	(28.5)
Sale of accounts receivable, net			(160.0)
Purchase of assets	(19.8)	(13.7)	
Other	(8.3)	(12.5)	(11.1)
Total	$(546.1)	$(546.4)	$(777.1)

Capital Requirements

Capacity — The Company anticipates that kilowatt-hour sales will grow approximately 2.36 percent a year through 2000. We will continue to pursue capacity acquisition plans to meet the anticipated load growth and maintain a high degree of service reliability. The additional capacity may be purchased from others or built by the Company if we can build capacity at a lower overall cost. We have long-term purchase agreements with Hoosier (400 MW) and AEP (500 MW) which will expire on December 31, 1999. We presently anticipate adding peaking capacity beginning in the year 2000 to meet future load growth.

Fixed Assets — The Company's construction and nuclear fuel expenditures (excluding AFC), during 1998, 1999 and 2000 are expected to total $588.1 million, $476.2 million and $395.1 million, respectively. The Company presently estimates that all of its 1998 construction and nuclear fuel expenditures will be met through cash flow from operations.

Long-term Debt — The Company will require $333.5 million to meet maturities of long-term debt in 1998, which we expect to meet with cash flow from operations and issuance of replacement debt securities. Other capital requirements will be met through a combination of sales of securities and short-term borrowings.

Customer Service — The Company has adopted a plan to improve customer service, requiring an investment in excess of $100 million. Our plan includes:

- installing automated electric meters in metropolitan and inaccessible rural and urban locations,
- installing a new work management system,
- making technological changes to enhance the Company's ability to handle customer calls during power outages,
- installing mobile data dispatch technology in the Company's service fleet, accompanied by digitized mapping of our service territory, and
- initiating both local and regional distribution line improvement projects.

Expenditures in 1997 for these projects were approximately $23 million; future expenditures are expected to be approximately $68 million in 1998 and $15 million in 1999. We anticipate funding these projects with cash flow from operations.

Results of Operations

The following is a discussion of results of operations for the years ended 1997 as compared to 1996, and 1996 as compared to 1995.

1997 Compared to 1996

Revenue changed from the prior year primarily due to the following:

	1997	1996
	(Millions)	
Revenue — Electric Service		
Customer growth	$ 55.8	$ 45.1
Weather	(111.1)	4.4
Base rate variance	(18.7)	(35.5)
Fuel rate variance	44.1	(89.6)
Other retail, net	47.7	41.5
Total retail	17.8	(34.1)
Other electric service	11.0	(49.8)
Total electric service	28.8	(83.9)
Revenue — Other		
Wholesale — power marketing	363.4	96.6
Natural gas	232.6	33.2
Other, net	33.3	23.1
Total revenue — other	629.3	152.9
Total revenue	$ 658.1	$ 69.0

Electric service revenue consists of sales to retail customers in our service territory at rates authorized by the Virginia and North Carolina Commissions and sales to cooperatives and municipalities at wholesale rates authorized by FERC. The primary factors affecting this revenue in 1997 were customer growth, weather, and fuel rates.

Customer growth — There were 50,899 new customer connections to our system in 1997, the largest number of new connections in any year since 1990. This had the effect of increasing our sales by $55.8 million in 1997 over 1996.

Weather — The mild weather in 1997 caused customers to use less electricity for heating and cooling, which reduced revenue by approximately $111.1 million from the previous year. Heating and cooling degree days were as follows:

	1997	1996	Normal
Cooling degree days	1,349	1,365	1,530
Percentage change compared to prior year	(1.2)%	(18.1)%	
Heating degree days	3,787	4,131	3,726
Percentage change compared to prior year	(8.3)%	9.0%	

Fuel rates — The increase in fuel rate revenues is primarily attributable to higher fuel rates which went into effect December 1, 1996, increasing recovery of fuel costs by approximately $48.2 million. The regulatory commissions having jurisdiction over the Company allow us to charge customers for the cost of fuel used in generating electricity.

Other revenue includes sales of electricity beyond our service territory, natural gas, nuclear consulting services, energy management services and other revenue. The growth in power marketing and natural gas sales revenue is primarily due to our success at marketing electricity and natural gas beyond our service territory. The Company began pursuing these new lines of business in 1996. We expect that revenue from such non-traditional business activities will continue to grow in the near future.

Kilowatt-hour sales changed as follows:

	Increase (Decrease) From Prior Year	
	1997	1996
Residential	(1.8)%	2.3%
Commercial	0.6	2.3
Industrial	2.1	2.3
Public authorities	(4.7)	2.6
Total retail sales	(0.5)	2.4
Wholesale — system	2.5	(24.3)
Wholesale — power marketing	196.0	200.3
Total sales	17.2	6.3

The decrease in retail kilowatt-hour sales in 1997 as compared to 1996 reflects the impact of weather on our traditional electricity service business, despite continued customer growth. The increase in wholesale kilowatt-hour sales was primarily due to the Company's power marketing efforts.

Fuel, net increased as compared to 1996, primarily due to the cost of the power marketing and natural gas sales which reflects increased purchases of energy from other wholesale power suppliers and purchases of natural gas.

System energy output by energy source and the average fuel cost for each are shown below. Fuel cost is presented in mills (one tenth of one cent) per kilowatt hour.

	1997		1996		1995	
	Source	Cost	Source	Cost	Source	Cost
Nuclear (*)	34%	4.52	32%	4.48	32%	4.92
Coal (**)	40	13.54	38	14.32	39	14.44
Oil	1	26.32	1	27.75	1	25.11
Purchased power, net	23	21.54	27	21.99	25	22.50
Other	2	30.65	2	26.98	3	23.82
Total	100%		100%		100%	
Average fuel cost		12.67		13.47		13.73

(*) Excludes ODEC's 11.6 percent ownership interest in the North Anna Power Station.

(**) Excludes ODEC's 50 percent ownership interest in the Clover Power Station.

Other operations and maintenance increased as compared to 1996 as a result of costs associated with the growth in sales by the Company's energy services business unit. These higher costs were offset partially by a reduction in expenses attributable to the Company's strategic initiatives. Expenses in 1996 include high storm damage costs resulting from destructive summer storms, including Hurricane Fran.

Depreciation and amortization increased as compared to 1996 due to the recognition of additional depreciation and nuclear decommissioning expense to reflect adjustments in the Company's filing currently pending before the Virginia Commission and higher depreciation expense related to Clover Unit 2, which began operations in March 1996. See Future Issues — *Utility Rate Regulation* for additional information on current rate proceedings.

Restructuring expenses decreased as compared to 1996 as the Company nears completion of its Vision 2000 strategic initiative. Charges for restructuring primarily include employee severance costs, costs to restructure agreements to purchase power from third parties and, when necessary, to negotiate settlement and termination of these contracts, and other costs. The Company estimates that staffing reductions will result in annual savings, in the range of $80 million to $90 million. However, these savings are being offset by salary increases, outsourcing costs and increased payroll costs associated with staffing for growth opportunities. See also Note O to the CONSOLIDATED FINANCIAL STATEMENTS.

Accelerated cost recovery represents a reserve for potential adjustments to regulatory assets. In this increasingly competitive environment, the Company has concluded that it is appropriate to utilize available cost reductions, such as those generated by the Vision 2000 program, to accelerate the write-off of unamortized regulatory assets and potentially stranded costs (see Future Issues — *Competition).*

1996 Compared to 1995

Electric service revenues decreased as compared to 1995 due to the effect of mild weather on the Company's summer retail rates, which are designed to reflect normal weather conditions. These revenues also were affected by reduced sales to Old Dominion Electric Cooperative (ODEC) due to the completion of Clover Units 1 and 2, of which ODEC owns a fifty percent interest.

Other revenues increased as compared to 1995 due to growth in our power marketing and energy services business, which was organized as a distinct business unit in 1996.

Fuel, net increased as compared to 1995, primarily as a result of increased energy purchases associated with our power marketing sales, offset in part by a higher recovery of fuel expenses subject to deferral accounting in 1995.

Operations and maintenance decreased slightly as compared to 1995, primarily as a result of a reduction in expenses attributable to the Company's strategic initiatives, offset partly by the high storm damage costs incurred in 1996 from destructive summer storms, including Hurricane Fran.

Depreciation and amortization increased as compared to 1995, primarily as a result of greater nuclear decommissioning expense and depreciation related to Clover Units 1 and 2, which were placed in service in October 1995 and March 1996, respectively.

Restructuring decreased as compared to 1995 as the implementation phase of the Vision 2000 initiative continued. Restructuring charges in 1996 included severance costs, costs to restructure or settle certain contracts to purchase power and other costs. In addition, 1995 restructuring costs included one-time charges to cancel specific capital projects and adjustments to inventory and certain real estate to reflect adoption of changes in business strategies and processes.

Accelerated cost recovery represents a provision for management's estimate of a reserve that may ultimately be used to accelerate the write-off of unamortized regulatory assets and potentially stranded costs (see Future Issues — *Competition*).

Future Issues

Competition in the Electric Industry — General

For most of this century, the structure of the electric industry in Virginia and throughout the United States has been relatively stable. We have recently seen, however, federal and state developments toward increased competition. Electric utilities have been required to open up their transmission systems for use by potential wholesale competitors. In addition, non-utility power producers now compete with electric utilities in the wholesale generation market. At the federal level, retail competition is under consideration. Some states have enacted legislation requiring retail competition.

Today, Virginia Power faces competition in the wholesale market. Currently, there is no general retail competition in Virginia Power's principal service area. To the extent that competition is permitted, Virginia Power's ability to sell power at prices that allow it to recover its prudently incurred costs may be an issue. See Future Issues — *Competition — Exposure to Potentially Stranded Costs.*

In response to competition, Virginia Power has successfully renegotiated long term contracts with wholesale and large federal government customers. In addition, the Company has obtained regulatory approval of innovative pricing proposals for large industrial customers. Rate concessions resulting from these contract negotiations and innovative pricing proposals are expected to reduce the Company's 1998 revenue by approximately $40 million. To date, the Company has not experienced any material loss of load.

Virginia Power is actively participating in the legislative and regulatory processes relating to industry restructuring. The Company has also responded to these trends toward competition by cutting its costs, re-engineering its core business processes, and pursuing innovative approaches to serving traditional markets and future markets. In addition, a significant part of the Company's strategy relies on developing "non-traditional" businesses within the Company's business units and subsidiaries designed to provide growth in future earnings, including:

- Energy Services — offering electric energy and capacity in the emerging wholesale market as well as natural gas, and other energy related products and services;
- Fossil & Hydro — targeting process type industries, such as chemical, paper, plastics and petroleum to become a service provider of instrumentation equipment;
- Nuclear Services — offering management and operations services to other electric utilities;

- Commercial Operations — providing power distribution related services, including transmission and distribution, engineering and metering services to other gas, water and electric utilities; and

- Telecommunications — offering telecommunications services through the Company's existing fiber-optic network.

The Company's non-traditional businesses face competition from a variety of utility and non-utility entities. In addition, Virginia Power may from time to time identify and investigate opportunities to expand its markets through strategic alliances with partners whose strengths, market position and strategies complement those of the Company.

Competition — Wholesale

During 1997, sales to wholesale customers represented approximately 17 percent of the Company's total revenues from electric sales. Approximately 73 percent of wholesale revenues resulted from the Company's power marketing efforts.

In July 1997, Virginia Power filed amendments to its existing rate tariffs with FERC so it could make wholesale sales at market-based rates. Under a FERC order conditionally accepting the Company rates for filing, Virginia Power began making market-based sales in 1997. FERC set for hearing in June 1998 the issue of whether transmission constraints limiting the transfer of power into the Company's service territory provide Virginia Power with generation dominance in localized markets. If FERC finds transmission constraints give Virginia Power generation dominance, it could revoke or limit the scope of the Company's market-based rate authority.

Virginia Power has successfully negotiated a new power supply arrangement with its largest wholesale customer. The new arrangement provides for a transition from cost-based rates to market-based rates, subject to FERC approval. Virginia Power estimates the reduced rates, offset in part by other revenues which may be earned under the agreement, will decrease income before taxes by approximately $38 million through 2005. Virginia Power anticipates that additional contract negotiations with other wholesale customers will take place in the future.

Competition — Retail

Currently, Virginia Power has the exclusive right to provide electricity at retail within its assigned service territories in Virginia and North Carolina. As a result, Virginia Power now only faces competition for retail sales if certain of its business customers move into another utility service territory, use other energy sources instead of electric power, or generate their own electricity. However, both Virginia and North Carolina are considering implementing retail competition.

Competition — Legislative Initiatives

Virginia: In the 1998 Session, the Virginia General Assembly passed House Bill No. 1172 (HB1172) to establish a schedule for Virginia's transition to retail competition in the electric utility industry. The Company actively supported HB1172, which passed both houses of the General Assembly in amended form and now awaits action by the Governor. HB1172 requires the following:

- establishment of one or more independent system operators (ISO) and one or more regional power exchanges (RPX) for Virginia by January 1, 2001;

- deregulation of generating facilities beginning January 1, 2002;

- transition to retail competition to begin on January 1, 2002, with retail competition to begin on January 1, 2004;

- recovery of just and reasonable net stranded costs; and

- appropriate consumer safeguards related to stranded costs and consideration of stranded benefits.

If HB1172 becomes law, it will become effective July 1, 1998. While the bill establishes a timeline for the transition to competition in Virginia, a detailed plan to implement that transition must be developed through future legislative and regulatory action. The Company is unable at this time to predict its timing or details.

Federal: The U.S. Congress is expected to consider federal legislation in the near future authorizing or requiring retail competition. Virginia Power cannot predict what, if any, definitive actions the Congress may take.

North Carolina: The 1997 Session of the North Carolina General Assembly created a Study Commission on the Future of Electric Service in North Carolina. An interim report is expected in 1998 with final recommendations made to the 1999 session of the North Carolina General Assembly.

Competition — Regulatory Initiatives

The Virginia Commission also has been actively interested in industry restructuring and competition, as shown in the following generic and utility-specific proceedings.

In 1995, the Commission instituted an ongoing generic investigation on restructuring, resulting in a number of reports by its Staff covering such issues as retail wheeling experiments and the status of wholesale power markets.

In November 1996, the Commission ordered Virginia Power to file studies and reports on possible restructuring of the electric industry in Virginia. The Commission also invited Virginia Power to submit a proposed alternative regulation plan with its filing. A two-phase alternative regulatory plan (ARP) was filed March 1997. During Phase I (1997 to December 2002), Virginia Power proposed implementing a freeze of its current base rates and devoting a portion of earnings above a 11.5% return-on-equity to accelerate the write-off of generation-related regulatory assets and to mitigate the costs associated with payments under power purchase contracts with non-utility generators that may be above market if competition is authorized in Virginia. During Phase II (beyond December 31, 2002), Virginia Power would seek Commission approval of stranded cost recovery if retail competition is implemented in Virginia and a transition cost charge mechanism by which stranded costs would be recovered. Virginia Power presented illustrative estimates of stranded costs based on hypothetical market prices as part of its Phase II filing. When the Company filed its ARP, the Commission consolidated its consideration of the ARP with its consideration of the Company's 1995 Annual Information Filing. For a discussion of the 1995 Annual Information Filing, See Future Issues — *Utility Rate Regulation.*

In November 1997, the Commission Staff issued its report to the General Assembly calling for a cautious, two-phase, five-year period to address restructuring issues. The report acknowledged the need for direction from the Virginia legislature concerning policy issues surrounding competition in the electric industry. Virginia Power sought to withdraw its ARP in December 1997, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP, but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing (See Future Issues — *Utility Rate Regulation).*

Competition — SFAS 71

Virginia Power's regulated rates are designed to recover its prudently incurred costs of providing service, including the opportunity to earn a reasonable return on its shareholder's investment. The Company's financial statements reflect assets and costs under this cost-based rate regulation in accordance with Statement of Financial Accounting Standards No. 71 (SFAS 71), "Accounting for the Effects of Certain Types of Regulation." SFAS 71 provides that certain expenses normally reflected in income are deferred on the balance sheet as regulatory assets and are recognized as the related amounts are included in rates and recovered from customers. Continued accounting under SFAS 71 requires that rates designed to recover the utility's specific costs of providing service, are, and will continue to be, established by regulators. The presence of increasing competition that limits the utility's ability to charge rates that recover its costs, or a change in the method of regulation with the same effect, could result in the discontinued applicability of SFAS 71.

Rate-regulated companies are required to write off regulatory assets against earnings whenever those assets no longer meet the criteria for recognition as defined by SFAS 71. In addition, SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," requires a review of long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Thus, events or changes in circumstances that cause the discontinuance of SFAS 71, and write off of regulatory assets, may also require a review of utility plant assets for possible impairment. If such review indicates utility plant assets are impaired, the carrying amount of the affected assets would be written down. This would result in a loss being charged to earnings, unless recovery of the loss is provided through operations that remain regulated.

Virginia Power's regulated operations currently satisfy the SFAS 71 criteria. However, if events or circumstances should change so that those criteria are no longer satisfied, management believes that a material adverse effect on the Company's results of operations and financial position may result. The form of cost-based rate regulation under which Virginia Power operates is likely to evolve as a result of various legislative or regulatory initiatives. At this time, management can predict neither the ultimate outcome of regulatory reform in the electric utility industry nor the impact such changes would have on Virginia Power.

Competition — Exposure to Potentially Stranded Costs

Under traditional cost-based regulation, utilities have generally had an obligation to serve supported by an implicit promise of the opportunity to recover prudently incurred costs. The most significant potential adverse effect of competition is "stranded costs." Stranded costs are those costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market.

The Company's potential exposure to stranded costs is comprised of the following:

- long-term purchased power contracts that may be above market (see Note Q to the CONSOLIDATED FINANCIAL STATEMENTS);
- costs pertaining to certain generating plants that may become uneconomic in a deregulated environment;
- regulatory assets for items such as income tax benefits previously flowed-through to customers, deferred losses on reacquired debt and other costs; (see Note F to the CONSOLIDATED FINANCIAL STATEMENTS); and
- unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements (see Notes C and N to the CONSOLIDATED FINANCIAL STATEMENTS).

Any forecast of potentially stranded costs is extremely sensitive to the various assumptions made. Such assumptions include:

- the timing and extent of customer choice in the market for electric service;
- estimates of future competitive market prices;
- sales and load growth forecasts;
- power stations' future operating performance;
- rate revenues permitted during the transition;
- estimated costs of utility operations over time;
- mitigation opportunities;
- stranded cost recovery mechanisms and other factors.

Certain combinations of these assumptions as applied to Virginia Power would produce little to no stranded costs; under other scenarios Virginia Power's exposure to potentially stranded costs could be substantial.

Virginia Power has assessed the reasonableness of various possible assumptions, but has not been able to settle on any particular combination thereof. Thus, the Company's maximum exposure to potentially stranded costs is uncertain. Management believes that recovery of any potentially stranded costs is appropriate and will vigorously pursue such recovery with the regulatory commissions having jurisdiction over its operations. However, Virginia Power cannot predict the extent to which such costs, if any, will be recoverable from customers. Also, in an effort to mitigate the amount at risk, the Company will continue to implement cost reduction measures.

Utility Rate Regulation

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. Virginia Power filed its ARP in March 1997, based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

Utility Operations

The Company strives to operate its generating facilities in accordance with prudent utility industry practices and in conformity with applicable statutes, rules and regulations. Like other electric utilities, the Company's generating facilities are subject to unanticipated or extended outages for repairs, replacements or modification of equipment or otherwise to comply with regulatory requirements. Such outages may involve significant expenditures not previously budgeted, including replacement energy costs.

On September 10, 1997, the NRC published a proposed rule for financial assurance requirements related to nuclear decommissioning. If the NRC's proposed rule were implemented without further clarification or modification, the Company may have to either pre-fund or provide acceptable security for a portion of its nuclear decommissioning obligation. See Note C to the CONSOLIDATED FINANCIAL STATEMENTS.

Environmental Matters

The Company is subject to rising costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations of the Company. These costs have been historically recovered from customers through utility rates. However, to the extent that the regulatory environment departs from cost-based rates, the Company's results of operations and financial condition could be adversely impacted.

Environmental Protection and Monitoring Expenditures

The Company incurred $70.4 million, $71.1 million and $68.3 million (including depreciation) during 1997, 1996 and 1995, respectively, in connection with the use of environmental protection facilities and expects these expenses to be approximately $69.1 million in 1998. In addition, capital expenditures to limit or monitor hazardous substances were $24.6 million, $22.4 million and $23.4 million for 1997, 1996 and 1995, respectively. The amount estimated for 1998 for these expenditures is $10.0 million.

Clean Air Act Compliance

The Clean Air Act, as amended in 1990, requires the Company to reduce its emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The Clean Air Act also requires the Company to obtain operating permits for all major emissions-emitting facilities. Permit applications have been submitted for the Company's power stations located in North Carolina and West Virginia. Applications for the Company's power stations located in Virginia will be filed in 1998.

The Clean Air Act's SO_2 reduction program is based on the issuance of a limited number of SO_2 emission allowances, each of which may be used as a permit to emit one ton of SO_2 into the atmosphere or may be sold to someone else. The program is administered by the EPA. The Company's compliance plans may include switching to lower sulfur coal, purchase of emission allowances and installation of SO_2 control equipment. Maximum flexibility and least-cost compliance will be maintained through annual studies.

The Company began complying with Clean Air Act Phase I NO_x limits at eight of its units in Virginia in 1997, three years earlier than otherwise required. As a result, the units will not be subject to more stringent Phase II limits until 2008. Furthermore, in order to avoid the necessity of more stringent regulations, the Company made voluntary commitments in 1996 to cap NO_x emissions at its Chesterfield and Yorktown Power Stations and the Chesapeake Energy Center during the ozone season beginning in 2000.

From 1994 through 1997, the Company invested more than $160 million to install and upgrade SO_2 and NO_x emission control equipment at its Mt. Storm and Possum Point power stations. Capital expenditures related to Clean Air Act compliance over the next five years are projected to be approximately $40 million. Changes in the regulatory environment, availability of allowances, and emissions control technology could substantially impact the timing and magnitude of compliance expenditures.

In November 1997, the EPA proposed new requirements for 22 states, including North Carolina, Virginia and West Virginia, to reduce and cap emissions of NO_x. The EPA will issue a final rule by September 1998. Although the proposal allows each state to determine how to achieve the required reduction in emissions, the caps were calculated based on emission limits for utility boilers. If the states in which Virginia Power operates choose to impose this limit, major additional emission control equipment, with attendant significant capital and operating costs, could be required.

Global Climate Change

In 1993, the United Nation's Global Warming Treaty became effective. The objective of the treaty is the stabilization of greenhouse gas concentrations at a level that would prevent man-made emissions from interfering with the climate system.

As a continuation of the effort to limit man-made greenhouse emissions, an international Protocol was formulated on December 10, 1997, in Kyoto, Japan. This Protocol calls for the United States to reduce greenhouse emissions by 7 percent from 1990 baseline levels by the period 2008-2012. The Protocol will not constitute a binding commitment unless submitted to and approved by the United States Senate. Emission reductions of the magnitude included in the Protocol, if adopted, would likely result in a substantial financial impact on companies that consume or produce fossil fuel-derived electric power, including Virginia Power.

Recently Issued Accounting Standards

During 1997, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 130, "Reporting Comprehensive Income," and SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Each of these statements is effective for fiscal years beginning after December 15, 1997. At this time, the Company does not expect the implementation of these standards to have a material impact on its results of operations or financial position.

Year 2000 Compliance

Virginia Power is taking an aggressive approach regarding computer issues associated with the onset of the new millenium — specifically, the impact of the possible failure of computer systems and computer-driven equipment due to the rollover to the year 2000. The year 2000 problem is pervasive and complex as virtually every computer operation could be affected in some way by the rollover of the two-digit year value from 99 to 00. The issue is whether computer systems will properly recognize date-sensitive information when the year changes to 2000. Systems that do not properly recognize such information could generate erroneous data or fail.

If not properly addressed, the year 2000 computer problem could result in failures in computer systems in the Company and the computer systems of third parties with which the Company transacts business. Such failures of the Company's or third parties' computer systems could have a material impact on the Company's ability to conduct business.

Since January 1997, the Company has organized a formal year 2000 project team to identify, correct or reprogram and test its systems for year 2000 compliance. At this time, the project team has completed its preliminary assessment. Based on the team's evaluation, the costs of testing and conversion of system applications are projected to be within the range of $30 million to $50 million. The range is a function of our ongoing evaluation as to whether certain systems and equipment will be corrected or replaced, which is dependent on information yet to be obtained from suppliers and other external sources. Maintenance or modification costs will be expensed as incurred, while the costs of new software and hardware will be capitalized and amortized over the asset's useful life.

At this time, Virginia Power is actively pursuing solutions to its year 2000-related computer problems in order to ensure that foreseeable situations related to Company computer systems are effectively addressed. The Company cannot estimate or predict the potential adverse consequences, if any, that could result from a third party's failure to effectively address this issue.

Market Rate Sensitive Instruments and Risk Management

Virginia Power is subject to market risk as a result of its use of various financial instruments and derivative commodity instruments. Interest rate risk generally is associated with the Company's outstanding debt, preferred stock and trust-issued securities. The Company also is exposed to interest rate risk as well as equity price risk as a result of its nuclear decommissioning trust investments in debt and equity securities.

The Company's wholesale power group is involved in trading activities which use derivative commodity instruments. However, the fair value of such instruments at December 31, 1997, is not material to the Company's financial position. Also, the potential near term losses in future earnings, fair values, or cash flows, resulting from reasonably possible near term changes in market prices for such instruments are not anticipated to be material to the Company's results of operations, financial position or cash flows.

The following analysis does not include the price risks associated with the nonfinancial assets and liabilities of utility operations, including underlying fuel requirements.

Interest-rate risk

Virginia Power uses both fixed rate and variable rate debt and preferred securities as sources of capital. The following table presents the financial instruments that are held or issued by the Company at December 31, 1997, and are sensitive to interest rate changes in some way. Weighted average variable rates are based on implied forward rates derived from appropriate annual spot rate observations as of December 31, 1997.

	Expected Maturity Date							
	1998	1999	2000	2001	2002	Thereafter	Total	Fair Value
	(Millions of Dollars, Except Percentages)							
ASSETS								
Nuclear decommissioning trust investments	$ 17.7	$ 5.3	$ 2.1	$ 7.1	$ 3.1	$ 165.0	$ 200.3	$ 190.7
Average interest rate (1)	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%		
LIABILITIES — Fixed rate								
Mortgage bonds	225.0	100.0	135.0	100.0	255.0	2,009.5	2,824.5	2,937.7
Average interest rate	6.7%	8.9%	5.9%	6.0%	4.5%	7.6%		
Medium term notes	108.5	221.0	60.5	60.6	60.0	40.5	551.1	573.7
Average interest rate	7.6%	8.5%	9.7%	8.4%	7.6%	9.0%		
Tax-exempt financing						10.0	10.0	10.4
Average interest rate						5.2%		
Short-term debt	226.2						226.2	226.2
Average interest rate	5.9%							
Preferred stock, subject to mandatory redemption			180.0				180.0	186.6
Average dividend rate			6.2%					
Mandatorily redeemable trust-issued preferred securities						135.0	135.0	137.7
Average dividend rate						8.1%		
LIABILITIES — Variable rate								
Tax-exempt financing (2)						488.6	488.6	488.6
Average interest rate						4.1%		

(1) Rates are based on average yield for entire portfolio at December 31, 1997.

(2) Interest rates on the tax-exempt bonds are based on short-term, tax-exempt market rates and are reset for periods of one to 270 days in length. The Company has the option to convert these bonds to fixed rate securities upon 40 days written notice. See Note H to the CONSOLIDATED FINANCIAL STATEMENTS.

Equity price risk

The following table presents a description of marketable equity securities held by the Company at December 31, 1997. As prescribed by Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities," these securities are reported on the balance sheet at fair value.

	Cost	Fair Value
	(Millions of Dollars)	
Nuclear decommissioning trust investments	$ 219.4	$ 360.4

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX

REPORT OF MANAGEMENT

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

Management maintains a system of internal accounting controls designed to provide reasonable assurance, at a reasonable cost, that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. Management recognizes the inherent limitations of any system of internal accounting control and, therefore, cannot provide absolute assurance that the objectives of the established internal accounting controls will be met. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits. Management believes that during 1997 the system of internal control was adequate to accomplish the intended objective.

The Consolidated Financial Statements have been audited by Deloitte & Touche LLP, independent auditors, who have been engaged by the Board of Directors. Their audits were conducted in accordance with generally accepted auditing standards and included a review of the Company's accounting systems, procedures and internal controls, and the performance of tests and other auditing procedures sufficient to provide reasonable assurance that the Consolidated Financial Statements are not materially misleading and do not contain material errors.

The Audit Committee of the Board of Directors, composed entirely of directors who are not officers or employees of the Company, meets periodically with the independent auditors, the internal auditors and management to discuss auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

Management recognizes its responsibility for fostering a strong ethical climate so that the Company's affairs are conducted according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in the Company's Code of Ethics, which is distributed throughout the Company. The Code of Ethics addresses, among other things, the importance of ensuring open communication within the Company; potential conflicts of interest; compliance with all domestic and foreign laws, including those relating to financial disclosure; the confidentiality of proprietary information; and full disclosure of public information.

VIRGINIA ELECTRIC AND POWER COMPANY

Norman Askew President and Chief Executive Officer	M. S. Bolton, Jr. Controller and Principal Accounting Officer

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors of Virginia Electric and Power Company:

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly owned subsidiary of Dominion Resources, Inc.) and subsidiaries (the Company) as of December 31, 1997 and 1996, and the related consolidated statements of income, earnings reinvested in business, and cash flows for each of the three years in the period ended December 31, 1997. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles.

DELOITTE & TOUCHE LLP

Richmond, Virginia
February 9, 1998

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31, 1997	1996	1995
	(Millions)		
Revenues:			
Electric service	$4,239.0	$4,210.2	$4,294.1
Other	840.0	210.7	57.8
Total	5,079.0	4,420.9	4,351.9
Expenses:			
Fuel, net	1,620.7	1,016.6	1,009.7
Purchased power capacity, net	717.5	700.6	688.4
Operations and maintenance	812.7	803.1	805.6
Depreciation and amortization	549.9	502.0	469.1
Restructuring	18.4	64.9	117.9
Accelerated cost recovery	38.4	26.7	
Amortization of terminated construction project costs	34.4	34.4	34.4
Taxes other than income	267.7	262.6	254.9
Total	4,059.7	3,410.9	3,380.0
Income from operations	1,019.3	1,010.0	971.9
Other income	14.2	6.8	10.0
Income before interest and income taxes	1,033.5	1,016.8	981.9
Interest and related charges:			
Interest expense, net	304.2	308.4	317.9
Distributions — preferred securities of subsidiary trust	10.9	10.9	3.7
Total	315.1	319.3	321.6
Income before income taxes	718.4	697.5	660.3
Income taxes	249.3	240.2	227.5
Net income	469.1	457.3	432.8
Preferred dividends	35.7	35.5	44.1
Balance available for Common Stock	$ 433.4	$ 421.8	$ 388.7

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS

Assets

(Millions of Dollars)	At December 31, 1997	1996
CURRENT ASSETS:		
Cash and cash equivalents	$ 36.0	$ 47.9
Accounts receivable:		
Customers (less allowance for doubtful accounts of $2.4 in 1997 and 1996)	462.4	354.8
Other	108.0	80.4
Accrued unbilled revenues	245.2	180.3
Materials and supplies at average cost or less:		
Plant and general	145.2	148.7
Fossil fuel	67.4	76.8
Other	134.7	107.0
Total current assets	1,198.9	995.9
INVESTMENTS:		
Nuclear decommissioning trust funds	569.1	443.3
Other	38.3	34.5
Total net investments	607.4	477.8
DEFERRED DEBITS AND OTHER ASSETS:		
Regulatory assets:		
Deferred capacity expenses	47.3	6.1
Other	729.3	767.8
Unamortized debt issuance costs	24.2	24.7
Other	127.1	121.9
Total deferred debits and other assets	927.9	920.5
UTILITY PLANT:		
Plant (includes plant under construction of $240.9 in 1997 and $180.1 in 1996)	14,794.2	14,506.8
Less accumulated depreciation	5,724.3	5,218.3
	9,069.9	9,288.5
Nuclear fuel (less accumulated amortization of $705.0 in 1997 and $698.5 in 1996)	149.3	145.3
Total net utility plant	9,219.2	9,433.8
Total assets	$11,953.4	$11,828.0

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED BALANCE SHEETS

Liabilities and Shareholders' Equity

(Millions of Dollars)	At December 31, 1997	At December 31, 1996
CURRENT LIABILITIES:		
Securities due within one year	$ 333.5	$ 311.3
Short-term debt	226.2	312.4
Accounts payable, trade	452.0	368.5
Customer deposits	44.6	50.0
Payrolls accrued	77.5	73.2
Severance costs accrued	29.7	50.2
Interest accrued	95.1	95.3
Other	161.6	126.1
Total current liabilities	1,420.2	1,387.0
LONG-TERM DEBT	3,514.6	3,579.4
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	1,607.0	1,565.2
Deferred investment tax credits	238.4	255.3
Deferred fuel expenses	12.8	3.3
Other	220.3	151.1
Total deferred credits and other liabilities	2,078.5	1,974.9
COMMITMENTS AND CONTINGENCIES (See Note Q)		
COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST*	135.0	135.0
PREFERRED STOCK:		
Preferred stock subject to mandatory redemption	180.0	180.0
Preferred stock not subject to mandatory redemption	509.0	509.0
COMMON STOCKHOLDER'S EQUITY:		
Common Stock, no par, 300,000 shares authorized, 171,484 shares outstanding at December 31, 1997 and 1996	2,737.4	2,737.4
Other paid-in capital	16.9	16.9
Earnings reinvested in business	1,361.8	1,308.4
Total common stockholder's equity	4,116.1	4,062.7
Total liabilities and shareholders' equity	$11,953.4	$11,828.0

(*) As described in Note I to CONSOLIDATED FINANCIAL STATEMENTS, the 8.05% Junior Subordinated Notes totalling $139.2 million principal amount constitute 100% of the Trust's assets.

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF EARNINGS REINVESTED IN BUSINESS

	For the Years Ended December 31,		
	1997	1996	1995
		(Millions)	
Balance at beginning of year	$1,308.4	$1,272.5	$1,277.8
Net income	469.1	457.3	432.8
Total	1,777.5	1,729.8	1,710.6
Cash dividends:			
Preferred stock subject to mandatory redemption	11.1	11.1	13.5
Preferred stock not subject to mandatory redemption	24.7	24.5	30.8
Common Stock	379.9	385.8	394.3
Total dividends	415.7	421.4	438.6
Other additions (deductions), net			0.5
Balance at end of year	$1,361.8	$1,308.4	$1,272.5

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1997	1996	1995
		(Millions)	
Cash Flow From Operating Activities:			
Net income	$ 469.1	$ 457.3	$ 432.8
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	664.7	616.0	585.1
Deferred income taxes	36.1	69.1	11.8
Deferred investment tax credits	(16.9)	(16.9)	(16.9)
Noncash return on terminated construction project costs — pretax	(4.2)	(6.4)	(8.4)
Deferred fuel expenses, net	9.6	(54.4)	6.2
Deferred capacity expenses	(41.2)	(9.2)	6.4
Restructuring	12.5	29.6	96.2
Accelerated cost recovery	38.4	26.7	
Changes in:			
Accounts receivable	(135.2)	(11.3)	(54.3)
Accrued unbilled revenues	(64.9)	17.6	(27.7)
Materials and supplies	12.9	6.0	61.1
Accounts payable, trade	82.8	57.8	(8.9)
Accrued expenses	(13.9)	(62.6)	44.7
Other	41.0	(4.0)	(2.7)
Net Cash Flow From Operating Activities	1,090.8	1,115.3	1,125.4
Cash Flow From (To) Financing Activities:			
Issuance of long-term debt	270.0	24.5	240.0
Issuance of preferred securities of subsidiary trust			135.0
Issuance (Repayment) of short-term debt	(86.2)	143.4	169.0
Repayment of long-term debt and preferred stock	(311.3)	(284.1)	(439.0)
Common Stock dividend payments	(379.9)	(385.8)	(394.3)
Preferred stock dividend payments	(35.7)	(35.6)	(44.3)
Distribution-preferred securities of subsidiary trust	(10.9)	(10.9)	(3.7)
Other	(2.6)	(2.3)	(10.0)
Net Cash Flow To Financing Activities	(556.6)	(550.8)	(347.3)
Cash Flow Used In Investing Activities:			
Utility plant expenditures (excluding AFC — other funds)	(397.0)	(393.8)	(519.9)
Nuclear fuel (excluding AFC — other funds)	(84.8)	(90.2)	(57.6)
Nuclear decommissioning contributions	(36.2)	(36.2)	(28.5)
Sale of accounts receivable, net			(160.0)
Purchase of assets	(19.8)	(13.7)	
Other	(8.3)	(12.5)	(11.1)
Net Cash Flow Used In Investing Activities	(546.1)	(546.4)	(777.1)
Increase in cash and cash equivalents	(11.9)	18.1	1.0
Cash and cash equivalents at beginning of year	47.9	29.8	28.8
Cash and cash equivalents at end of year	$ 36.0	$ 47.9	$ 29.8
Cash paid during the year for:			
Interest (reduced for the cost of borrowed funds capitalized as AFC)	$ 277.1	$ 295.4	$ 314.5
Income taxes	230.0	216.1	215.8

The accompanying notes are an integral part of the financial statements.

VIRGINIA ELECTRIC AND POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Significant Accounting Policies:

General

Virginia Electric and Power Company is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy within a 30,000 square-mile area in Virginia and northeastern North Carolina. It sells electricity to retail customers (including governmental agencies) and to wholesale customers such as rural electric cooperatives, municipalities, power marketers and other utilities. The Virginia service area comprises about 65 percent of Virginia's total land area, but accounts for over 80 percent of its population. The Company has organized a wholesale power group to engage in off-system wholesale purchases and sales of electricity and purchases and sales of natural gas, and that group is developing trading relationships beyond the geographic limits of Virginia Power's retail service territory. Within this document, the terms "Virginia Power" and the "Company" shall refer to the entirety of Virginia Electric and Power Company, including, without limitation, its Virginia and North Carolina operations, and all of its subsidiaries.

The Company's accounting practices are generally prescribed by the Uniform System of Accounts promulgated by the regulatory commissions having jurisdiction and are in accordance with generally accepted accounting principles applicable to regulated enterprises. The financial statements include the accounts of the Company and its subsidiaries, with all significant intercompany transactions and accounts being eliminated on consolidation.

The Company is a wholly-owned subsidiary of Dominion Resources, Inc., a Virginia corporation.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent liabilities at the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenues

Revenues are recorded on the basis of services rendered, commodities delivered or contracts settled.

Property, Plant and Equipment

Utility plant is recorded at original cost, which includes labor, materials, services, AFC, where permitted by regulators, and other indirect costs. The cost of maintenance and repairs is charged to the appropriate operating expense and clearing accounts. The cost of additions and replacements is charged to the appropriate utility plant account, except that the cost of minor additions and replacements, as provided in the Uniform System of Accounts, is charged to maintenance expense.

Depreciation and Amortization

Depreciation of utility plant (other than nuclear fuel) is computed on the straight-line method based on projected useful service lives. The cost of depreciable utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation. The provision for depreciation provides for the recovery of the cost of assets including the estimated cost of removal, net of salvage, and is based on the weighted average depreciable plant using a rate of 3.2 percent for 1997, 1996 and 1995.

Operating expenses include amortization of nuclear fuel, which is provided on a unit of production basis sufficient to fully amortize, over the estimated service life, the cost of the fuel plus permanent storage and disposal costs.

Federal Income Taxes

The Company files a consolidated federal income tax return with Dominion Resources.

Deferred investment tax credits are being amortized over the service lives of the property giving rise to such credits.

Allowance for Funds Used During Construction

The applicable regulatory Uniform System of Accounts defines AFC as the cost during the construction period of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.

The pretax AFC rates for 1997, 1996 and 1995 were 6.6 percent, 8.1 percent and 8.9 percent, respectively. No AFC is accrued for approximately 83 percent of the Company's construction work in progress, which is instead included in rate base. A cash return is currently collected on the portion of construction work in progress included in rate base.

Deferred Capacity and Deferred Fuel Expense

Approximately 80 percent of capacity expenses and 90 percent of fuel expenses incurred as part of providing regulated electric service are subject to deferral accounting. The difference between reasonably incurred actual expenses and the level of expenses included in current rates is deferred and matched against future revenues.

Amortization of Debt Issuance Costs

The Company defers and amortizes any expenses incurred in the issuance of long-term debt, including premiums and discounts associated with such debt, over the lives of the respective issues. Any gains or losses resulting from the refinancing of debt are also deferred and amortized over the lives of the new issues of long-term debt as permitted by the appropriate regulatory jurisdictions. Gains or losses resulting from the redemption of debt without refinancing are amortized over the remaining lives of the redeemed issues.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 1997 and 1996, the Company's accounts payable included the net effect of checks outstanding but not yet presented for payment of $55.8 million and $64.8 million, respectively. For purposes of the Consolidated Statements of Cash Flows, the Company considers cash and cash equivalents to include cash on hand and temporary investments purchased with an initial maturity of three months or less.

Commodity Contracts

The trading activities of Virginia Power's wholesale power group include fixed-price forward contracts and the purchase and sale of over-the-counter options that require physical delivery of the underlying commodity. Furthermore, in order to manage price risk associated with natural gas sales and fuel requirements for the utility operations, the Company uses exchange-for-physical contracts, basis swaps, NYMEX natural gas futures contracts, as well as options on natural gas futures contracts.

Options, exchange-for-physical contracts, basis swaps and futures contracts are marked to market with resulting gains and losses reported in earnings, unless such instruments are designated as hedges for accounting purposes. Fixed price forward contracts, initiated for trading purposes, also are marked to market with resulting gains and losses reported in earnings. For exchange-for-physical contracts, basis swaps, fixed price forward contracts and options which require physical delivery of the underlying commodity, market value reflects management's best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Futures contracts and options on futures contracts are marked to market based on closing exchange prices. No contracts were designated as hedges during 1997.

Purchased options and options sold are reported in Deferred Debits and Other Assets — Other and in Deferred Credits and Other Liabilities — Other, respectively, until exercise or expiration. Gains and losses resulting from marking positions to market are reported in Other Income. Net gains and losses resulting from futures contracts and options on futures contracts and settlement of basis swaps are included in Fuel, Net. Amortization of option premiums associated with sales and purchases are included in Revenues — Other and Fuel, Net, respectively. Cash flows from trading activities are reported in Net Cash Flow from Operating Activities.

Reclassification

Certain amounts in the 1996 and 1995 financial statements have been reclassified to conform to the 1997 presentation.

B. Income Taxes:

Details of income tax expense are as follows:

	Years 1997	1996 (Millions)	1995
Current expense:			
Federal	$222.1	$185.6	$230.6
State	8.6	2.4	2.1
	230.7	188.0	232.7
Deferred expense:			
Utility plant differences	41.3	65.4	48.9
Deferred fuel and capacity	11.0	22.3	(6.0)
Debt issuance costs	(2.1)	(2.8)	1.3
Terminated construction project costs	(5.8)	(5.1)	(4.4)
Other	(8.9)	(10.7)	(28.1)
	35.5	69.1	11.7
Net deferred investment tax credits-amortization	(16.9)	(16.9)	(16.9)
Total income tax expense	$249.3	$240.2	$227.5

Total federal income tax expense differs from the amount computed by applying the statutory federal income tax rate to pretax income for the following reasons:

	Years 1997	1996 (Millions)	1995
Federal income tax expense at statutory rate of 35 percent	$251.4	$244.1	$231.1
Increases (decreases) resulting from:			
Utility plant differences	7.7	5.7	3.2
Ratable amortization of investment tax credits	(16.9)	(16.9)	(16.9)
Terminated construction project costs	5.0	5.0	5.0
State income tax, net of federal tax benefit	4.9	2.4	2.2
Other, net	(2.8)	(0.1)	2.9
	(2.1)	(3.9)	(3.6)
Total income tax expense	$249.3	$240.2	$227.5
Effective tax rate	34.7%	34.4%	34.5%

The Company's net accumulated deferred income taxes consist of the following:

	Years 1997 (Millions)	1996
Deferred income tax assets:		
Investment tax credits	$ 84.4	$ 90.3
Deferred income tax liabilities:		
Utility plant differences	1,479.8	1,440.5
Terminated construction project costs	8.6	14.4
Income taxes recoverable through future rates	169.5	168.8
Other	33.5	31.8
Total deferred income tax liabilities	1,691.4	1,655.5
Total net accumulated deferred income taxes	$1,607.0	$1,565.2

C. Nuclear Operations:

Decommissioning

When the Company's nuclear units cease operations, we are obligated to decontaminate or remove radioactive contaminants so that the property will not require NRC oversight. This phase of a nuclear power plant's life cycle is termed decommissioning. While the units are operating, we are collecting from ratepayers amounts that, when combined with investment earnings, will be used to fund this future obligation.

The amount being accrued for decommissioning is equal to the amount being collected from ratepayers and is included in Depreciation and Amortization Expense. The decommissioning collections were $45.8 million, $36.2 million and $28.5 million in 1997, 1996 and 1995, respectively. These dollars are deposited into external trusts through which the funds are invested.

Net earnings of the trusts' investments are included in Other Income in the Company's Consolidated Statements of Income. In 1997, 1996 and 1995, respectively, net earnings were $20.5 million, $16.0 million and $15.9 million. The accretion of the decommissioning obligation is equal to the trusts' net earnings and also is recorded in Other Income. Thus, the net impact of the trusts on Other Income is zero.

The accumulated provision for decommissioning, which is included in Utility Plant Accumulated Depreciation in the Company's Consolidated Balance Sheets, includes the accrued expense and accretion described above and any unrealized gains and losses on the trusts' investments. At December 31, 1997, the net unrealized gains were $149.5 million, which is an increase of $69.0 over the December 31, 1996, amount of $80.5 million. The total accumulated provision for decommissioning at December 31, 1997, was $578.7 million, including $9.6 million accrued in 1997 and deposited to the trusts in January 1998. The provision was $443.3 million at December 31, 1996.

The total estimated cost to decommission the Company's four nuclear units is $1 billion based upon a site-specific study that was completed in 1994. We plan to update this estimate in 1998. The cost estimate assumes that the method of completing decommissioning activities is prompt dismantlement. This method assumes that dismantlement and other decommissioning activities will begin shortly after cessation of operations, which under current operating licenses will begin in 2012 as detailed in the table below.

	Surry		North Anna		Total
	Unit 1	Unit 2	Unit 1	Unit 2	All Units
NRC license expiration year	2012	2013	2018	2020	
	(Millions)				
Current cost estimate (1994 dollars)	$272.4	$274.0	$247.0	$253.6	$1,047.0
Funds in external trusts at 12/31/97	156.5	151.8	134.2	126.6	569.1
1997 contribution to external trusts	10.6	10.8	7.6	7.2	36.2

The Financial Accounting Standards Board (FASB) is reviewing the accounting for nuclear plant decommissioning. In 1996, the FASB tentatively determined that the estimated cost of decommissioning should be reported as a liability rather than as accumulated depreciation and that a substantial portion of the decommissioning obligation should be recognized earlier in the operating life of the nuclear unit. If the industry's accounting were changed to reflect FASB's tentative proposal, then the annual provisions for nuclear decommissioning would increase. During its deliberations, the FASB expanded the scope of the project to include similar unavoidable obligations to perform closure and post-closure activities for non-nuclear power plants. Therefore, any forthcoming standard also may change industry plant depreciation practices. Any impact related to other Company assets cannot be determined at this time.

Insurance

The Price-Anderson Act limits the public liability of an owner of a nuclear power plant to $8.9 billion for a single nuclear incident. The Price-Anderson Amendments Act of 1988 allows for an inflationary provision adjustment every five years. The Company has purchased $200 million of coverage from the commercial insurance pools with the remainder provided through a mandatory industry risk sharing program. In the event of a nuclear incident at any licensed nuclear reactor in the United States, the Company could be assessed up to $81.7 million (including a 3 percent insurance premium tax for Virginia) for each of its four licensed reactors not to exceed $10.3 million (including a 3 percent insurance premium tax for Virginia) per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed.

Nuclear liability coverage for claims made by nuclear workers first hired on or after January 1, 1988, except those arising out of an extraordinary nuclear occurrence, is provided under the Master Worker insurance program. (Those first hired into the nuclear industry prior to January 1, 1988, are covered by the policy discussed above.) The aggregate limit of coverage for the industry is $400 million ($200 million policy limit with automatic reinstatements of an additional $200 million). The Company's maximum retrospective assessment is approximately $12.3 million (including a 3 percent insurance premium tax for Virginia).

The Company's current level of property insurance coverage ($2.55 billion for North Anna and $2.40 billion for Surry) exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. The Company's nuclear property insurance is provided by Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL), two mutual insurance companies, and is subject to retrospective premium assessments, in any policy year in which losses exceed the funds available to these insurance companies. The maximum assessment for the current policy period is $37.0 million. Based on the severity of the incident, the Boards of Directors of the Company's nuclear insurers have the discretion to lower the maximum retrospective premium assessment or eliminate either or both completely. For any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination, the Company has the financial responsibility for these losses.

The Company purchases insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, Virginia Power is subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period's maximum assessment is $8.7 million.

As part owner of the North Anna Power Station, ODEC is responsible for its share of the nuclear decommissioning obligation and insurance premiums applicable to that station, including any retrospective premium assessments and any losses not covered by insurance.

D. Utility Plant:

Utility plant consisted of the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Production	$ 7,684.2	$ 7,691.9
Transmission	1,415.7	1,386.5
Distribution	4,559.2	4,385.4
Other	894.2	862.9
	14,553.3	14,326.7
Construction work in progress	240.9	180.1
Total	$14,794.2	$14,506.8

E. Jointly Owned Plants:

The following information relates to the Company's proportionate share of jointly owned plants at December 31, 1997:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station
Ownership interest	60.0%	88.4%	50.0%
		(Millions)	
Utility plant in service	$1,072.9	$1,819.4	$533.3
Accumulated depreciation	229.1	819.2	26.3
Nuclear fuel		403.6	
Accumulated amortization of nuclear fuel		383.4	
Construction work in progress	.1	61.2	1.1

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly owned facilities in the same proportion as their respective ownership interest. The Company's share of operating costs is classified in the appropriate operating expense (fuel, operations and maintenance, depreciation, taxes, etc.) in the Consolidated Statements of Income.

F. Regulatory Assets-Other

Certain expenses normally reflected in income are deferred on the balance sheet as regulatory assets and are recognized in income as the related amounts are included in rates and recovered from customers. The Company's regulatory assets included the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Income taxes recoverable through future rates	$478.9	$477.0
Cost of decommissioning DOE uranium enrichment facilities	67.6	73.5
Deferred losses on reacquired debt, net	85.4	91.5
North Anna Unit 3 project termination costs	42.3	73.1
Other	55.1	52.7
Total	$729.3	$767.8

Income taxes recoverable through future rates represent principally the tax effect of depreciation differences not normalized in earlier years for ratemaking purposes. These amounts are amortized as the related temporary differences reverse.

The costs of decommissioning the Department of Energy's (DOE) uranium enrichment facilities have been deferred and represent the unamortized portion of Virginia Power's required contributions to a fund for decommissioning and decontaminating the DOE's uranium enrichment facilities. Virginia Power is making such contributions over a 15-year period with escalation for inflation. These costs are being recovered in fuel rates.

Losses or gains on reacquired debt are deferred and amortized over the lives of the new issues of long-term debt. Gains or losses resulting from the redemption of debt without refinancing are amortized over the remaining lives of the redeemed issues.

The construction of North Anna Unit 3 was terminated in November 1982. All retail jurisdictions have permitted recovery of the incurred costs. For Virginia and FERC jurisdictional customers, the amounts deferred are being amortized from the date termination costs were first includible in rates.

The incurred costs underlying these regulatory assets may represent expenditures by the Company or may represent the recognition of liabilities that ultimately will be settled at some time in the future. For some of those regulatory assets representing past expenditures that are not included in the Company's rate base or used to adjust the Company's capital structure, the Company is not allowed to earn a return on the unrecovered balance. Of the $729.3 million of regulatory assets at December 31, 1997, approximately $57.7 million represent past expenditures that are effectively excluded from rate base by the Virginia State Corporation Commission which has primary jurisdiction over the Company's rates. However, of that amount $42.3 million represent the present value of amounts to be recovered through future rates for North Anna Unit 3 project termination costs, and thus reflect a reduction in the actual dollars to be recovered through future rates for the time value of money. The Company does not earn a return on the remaining $15.4 million of regulatory assets, effectively excluded from rate base, to be recovered over various recovery periods up to 21 years, depending on the nature of the deferred costs.

G. Leases:

Plant and property under capital leases included the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Office buildings (*)	$34.4	$34.4
Data processing equipment	13.3	2.5
Total plant and property under capital leases	47.7	36.9
Less accumulated amortization	17.8	13.3
Net plant and property under capital leases	$29.9	$23.6

(*) The Company leases its principal office building from its parent, Dominion Resources. The capitalized cost of the property under that lease, net of accumulated amortization, represented $22 million and $23 million at December 31, 1997 and 1996, respectively. Rental payments for such lease were $3 million for each of the three years ended December 31, 1997, 1996 and 1995.

The Company is responsible for expenses in connection with the leases noted above, including maintenance.

Future minimum lease payments under noncancellable capital leases and for operating leases that have initial or remaining lease terms in excess of one year as of December 31, 1997, are as follows:

	Capital Leases	Operating Leases
	(Millions)	
1998	$ 7.1	$11.4
1999	6.4	9.9
2000	4.3	7.1
2001	3.2	3.9
2002	3.0	3.2
After 2002	16.7	22.9
Total future minimum lease payments	$40.7	$58.4
Less interest element included above	10.8	
Present value of future minimum lease payments	$29.9	

Rents on leases, which have been charged to operations expense, were $17.6 million, $16.5 million and $13.6 million for 1997, 1996 and 1995, respectively.

H. Long-term Debt:

Long-term debt included the following:

	At December 31, 1997	At December 31, 1996
	(Millions)	
First and Refunding Mortgage Bonds (1):		
Series U, 5.125%, due 1997		$ 49.3
1992 Series B, 7.25%, due 1997		250.0
1988 Series A, 9.375%, due 1998	$ 150.0	150.0
1992 Series F, 6.25%, due 1998	75.0	75.0
1989 Series B, 8.875%, due 1999	100.0	100.0
1993 Series C, 5.875%, due 2000	135.0	135.0
Various series, 6.0-8%, due 2001-2004	805.0	805.0
Various series 6.75%-7.625%, due 2007	415.0	215.0
Various series, 5.45%-8.75%, due 2021-2025	1,144.5	1,144.5
Total First and Refunding Mortgage Bonds	2,824.5	2,923.8
Other long-term debt:		
Term notes:		
Fixed interest rate, 6.15%-10.00%, due 1997-2003	551.1	503.1
Tax exempt financings (2):		
Money Market Municipals, due 2007-2027(3)	488.6	488.6
Convertible interest rate, due 2022	10.0	
Total other long-term debt	1,049.7	991.7
	3,874.2	3,915.5
Less amounts due within one year:		
First and Refunding Mortgage Bonds	225.0	299.3
Term notes	108.5	12.0
Total amount due within one year	333.5	311.3
Less unamortized discount, net of premium	26.1	24.8
Total long-term debt	$3,514.6	$3,579.4

(1) The First and Refunding Mortgage Bonds are secured by a mortgage lien on substantially all of the Company's property.

(2) Certain pollution control facilities at the Company's generating facilities have been pledged or conveyed to secure the financings.

(3) Interest rates vary based on short-term, tax-exempt market rates. For 1997 and 1996, the weighted average daily interest rates were 3.74 percent and 3.57 percent, respectively. Although these bonds are re-marketed within a one year period, they are classified as long-term debt because the Company intends to maintain the debt and they are supported by long-term bank commitments.

The following amounts of debt will mature during the next five years (in millions): 1998 — $333.5; 1999 — $321.0; 2000 — $195.5; 2001 — $160.7; and 2002 — $315.0.

I. Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust:

Virginia Power Capital Trust I (VP Capital Trust) was established as a subsidiary of the Company for the sole purpose of selling $135 million of Preferred Securities (5.4 million shares at $25 par) in 1995. The Company concurrently issued $139.2 million of its 1995 Series A, 8.05% Junior Subordinated Notes (the Notes) in exchange for the $135 million realized from the sale of the Preferred Securities and $4.2 million of common securities of VP Capital Trust. The Preferred Securities and the common securities represent the total beneficial ownership interest in the assets held by VP Capital Trust. The Notes are the sole assets of VP Capital Trust.

The Preferred Securities are subject to mandatory redemption upon repayment of the Notes at a liquidation amount of $25 plus accrued and unpaid distributions, including interest. The Notes are due September 30, 2025. However, that date may be extended up to an additional ten years if certain conditions are satisfied.

J. Preferred Stock Subject to Mandatory Redemption:

The total number of authorized shares for all preferred stock (whether or not subject to mandatory redemption) is 10,000,000 shares. Upon involuntary liquidation, dissolution or winding-up of the Company, all presently outstanding preferred stock is entitled to receive $100 per share plus accrued dividends. Dividends are cumulative.

There are two series of preferred stock subject to mandatory redemption outstanding as of December 31, 1997:

Dividend	Issued and Outstanding Shares	
$5.58	400,000	Shares are non-callable prior to redemption at 3/1/2000
$6.35	1,400,000	Shares are non-callable prior to redemption at 9/1/2000
Total	1,800,000	

There were no redemptions of preferred stock during 1997 or 1996. In 1995, the Company redeemed 417,319 shares of its $7.30 dividend preferred stock subject to mandatory redemption.

K. Preferred Stock Not Subject to Mandatory Redemption:

Shown below are the series of preferred stock not subject to mandatory redemption that were outstanding as of December 31, 1997.

		Entitled per Share upon Liquidation		
Dividend	Issued and Outstanding Shares	Amount	Through	And Thereafter to Amounts Declining in Steps to
$5.00	106,677	$112.50		
4.04	12,926	102.27		
4.20	14,797	102.50		
4.12	32,534	103.73		
4.80	73,206	101.00		
7.05	500,000	105.00	7/31/03	$100.00 after 7/31/13
6.98	600,000	105.00	8/31/03	$100.00 after 8/31/13
MMP 1/87 (*)	500,000	100.00		
MMP 6/87 (*)	750,000	100.00		
MMP 10/88 (*)	750,000	100.00		
MMP 6/89 (*)	750,000	100.00		
MMP 9/92, Series A (*)	500,000	100.00		
MMP 9/92, Series B (*)	500,000	100.00		
Total	5,090,140			

(*) Money Market Preferred (MMP) dividend rates are variable and are set every 49 days via an auction process. The combined weighted average rates for these series in 1997, 1996 and 1995, including fees for broker/dealer agreements, were 4.71 percent, 4.48 percent and 4.93 percent, respectively.

In 1995, the Company redeemed 400,000 shares of its $7.45 dividend preferred stock not subject to mandatory redemption and 450,000 shares of its $7.20 dividend preferred stock not subject to mandatory redemption.

L. Common Stock:

There were no changes in the number of authorized and outstanding shares of the Company's Common Stock during the three years ended December 31, 1997.

M. Short-term Debt:

The Company's commercial paper program has a maximum borrowing capacity of $500 million. It is supported by two credit facilities. One is a $300 million, five-year credit facility that was effective on June 7, 1996, and expires on June 7, 2001. The other is a $200 million credit facility that originated on June 7, 1996, with an initial term of 364 days and provisions for subsequent 364-day extensions. It was renewed on June 6, 1997, for 364 days.

The total amount of commercial paper outstanding as of December 31, 1997, was $226.2 million with a weighted average interest rate of 5.88 percent. This represents a decrease of $86.2 million from the December 31, 1996, balance of $312.4 million and a weighted average interest rate of 5.51 percent.

N. Retirement Plan, Postretirement Benefits and Other Benefits:

Under the terms of its benefit plans, the Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Retirement Plan

The Company participates in the Dominion Resources, Inc. Retirement Plan (the Retirement Plan), a defined benefit pension plan. The benefits are based on years of service and average base compensation over the consecutive 60-month period in which pay is highest.

The Company's pension plan expenses were $20.6 million, $24.8 million and $20.3 million for 1997, 1996 and 1995, respectively, and the amounts funded by the Company were $27.0 million, $28.4 million and $42.7 million in 1997, 1996 and 1995, respectively.

Postretirement Benefits

In addition to providing pension benefits, Dominion Resources and the Company provide certain health care and life insurance benefits for retired employees. Health care benefits are provided to retirees who have completed at least 10 years of service after attaining age 45. These and similar benefits for active employees are provided through insurance companies. Under the terms of its benefit plans, the Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Net periodic postretirement benefit expense was as follows:

	Year Ended December 31,	
	1997	1996
	(Millions)	
Service cost	$ 12.3	$ 12.1
Interest cost	25.1	23.9
Return on plan assets	(25.3)	(16.6)
Amortization of transition obligation	12.1	12.1
Net amortization and deferral	13.4	7.1
Net periodic postretirement benefit expense	$ 37.6	$ 38.6

The following table sets forth the funded status of the plan:

	At December 31, 1997	At December 31, 1996
	(Millions)	
Fair value of plan assets	$ 176.6	$ 133.0
Accumulated postretirement benefit obligation:		
Retirees	$ 224.5	$ 201.7
Active plan participants	136.3	122.2
Accumulated postretirement benefit obligation	360.8	323.9
Accumulated postretirement benefit obligation in excess of plan assets	(184.2)	(190.9)
Unrecognized transition obligation	180.8	192.8
Unrecognized net experience (gain)/loss	(1.8)	(3.6)
Accrued postretirement benefit cost	$ (5.2)	$ (1.7)

A one percent increase in the health care cost trend rate would result in an increase of $5.0 million in the service and interest cost components and a $39.5 million increase in the accumulated postretirement benefit obligation.

Significant assumptions used in determining the postretirement benefit obligation were:

	1997	1996
Discount rates	7.75%	8%
Assumed return on plan assets	9%	9%
Medical cost trend rate	6% for 1st year	7% for 1st year
	5% for 2nd year	6% for 2nd year
	Scaling down to 4.75% beginning in the year 2000	Scaling down to 4.75% beginning in the year 2000

The Company is recovering these costs in rates on an accrual basis in all material respects, in all jurisdictions. The funds being collected for Other Postretirement Benefits (OPEB) in rates, in excess of OPEB benefits actually paid during the year, are contributed to external benefit trusts under the Company's current funding policy (see Future Issues — *Competition — Exposure to Potentially Stranded Costs* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS).

O. Restructuring:

The Company announced the implementation phase of its Vision 2000 program in March 1995. During this phase, the Company began reviewing operations with the objective of outsourcing services where economical and appropriate and re-engineering the remaining functions to streamline operations. The re-engineering process has resulted in outsourcing, decentralization, reorganization and downsizing for portions of the Company's operations. As part of this process, the Company has reevaluated its utilization of capital resources in the operations of the Company to identify further opportunities for operational efficiencies through outsourcing or re-engineering of its processes.

Restructuring charges of $18.4 million, $64.9 million, and $117.9 million in 1997, 1996 and 1995, respectively, included severance costs, purchased power contract restructuring and negotiated settlement costs, capital project cancellation costs, and other costs incurred directly as a result of the Vision 2000 initiatives. While the Company may incur additional charges for severance in 1998, the amounts are not expected to be significant.

Employee Severance

In 1995, the Company established a comprehensive involuntary severance package for salaried employees who may no longer be employed as a result of these initiatives. The Company is recognizing the cost associated with employee terminations in accordance with Emerging Issues Task Force Consensus No. 94-3 as management identifies the positions to be eliminated. Severance payments will be made over a period not to exceed twenty months. Through December 31, 1997, management had identified 1,977 positions to be eliminated. The recognition of severance costs resulted in charges to operations in 1997, 1996 and 1995 of $12.5 million, $49.2 million and $51.2 million, respectively. At December 31, 1997, 1,619 employees had been terminated and severance payments totaling $74 million had been paid. The Company estimates that these staffing reductions will result in annual savings, in the range of $80 million to $90 million. However, such savings are being offset by salary increases, outsourcing costs and increased payroll costs associated with staffing for growth opportunities.

Purchased Power Contracts

In an effort to minimize its exposure to potential stranded investment, the Company is evaluating its long-term purchased power contracts and negotiating modifications to their terms, including cancellations, where it is determined to be economically advantageous to do so. The Company has also negotiated settlements with several other parties to terminate their rights to sell power to the Company. The cost of contract modifications, contract cancellations and negotiated settlements was $3.8 million, $7.8 million and $8.1 million in 1997, 1996 and 1995, respectively. Using contract terms, estimated quantities of power that would have otherwise been delivered and other relevant factors at the time of each transaction, the Company estimated that its annual future purchased power costs, including energy payments, would be reduced by up to $0.8 million, $5.8 million and $147.0 million for the 1997, 1996 and 1995 transactions, respectively. The cost of alternative sources of power that might ultimately be required as a result of these settlements is expected to be significantly less than the estimated reduction in purchased power costs.

Construction Project

Restructuring charges reported in 1995 included $37.3 million for the cancellation of a project to construct a facility to handle low level radioactive waste at the Company's North Anna Power Station. As a result of reevaluating the handling of low level radioactive waste, the Company concluded that the facility should not be completed due to the additional capital investment required, decreased Company volumes of low level radioactive waste resulting from improvements in station procedures and the availability of more economical offsite processing.

P. Accelerated Cost Recovery:

In this increasingly competitive environment, the Company also has concluded that it is appropriate to utilize available cost reductions, such as those generated by the Vision 2000 program (see Note O to the CONSOLIDATED FINANCIAL STATEMENTS), to accelerate the write-off of existing unamortized regulatory assets. Not only will this strategically position the Company in anticipation of competition, but it also reflects the Company's commitment to mitigate its exposure to potentially stranded costs (see Competition in MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS). The Company identified savings of $38.4 million in 1997 and $26.7 million in 1996 which were used to establish a reserve for expected adjustments to regulatory assets.

Q. Commitments and Contingencies:

The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Utility Rate Regulation

In March 1997, the Virginia Commission issued an order that Virginia Power's base rates be made interim and subject to refund as of March 1, 1997. This order was the result of the Commission Staff's report on its review of Virginia Power's 1995 Annual Informational Filing, which concluded that Virginia Power's present rates would cause Virginia Power to earn in excess of its authorized return on equity. The Staff found that, for purposes of establishing rates prospectively, a rate reduction of $95.6 million (including a one-time adjustment of $29.7 million to Virginia Power's deferred capacity balance at December 31, 1996) may be necessary in order to realign rates to the authorized level. In March 1997, Virginia Power filed its Alternative Regulatory Plan (ARP) based on 1996 financial information. Subsequently, the Commission consolidated the proceeding concerned with the 1995 Annual Informational Filing with the proceeding that includes the ARP proposed by the Company.

In December 1997, Virginia Power sought to withdraw its ARP, having concluded that resolution of the cost recovery issues raised by the ARP was unlikely without General Assembly action. The Commission has agreed that the Company may withdraw its support of the ARP but has reserved the right to continue consideration of the ARP as well as other regulatory alternatives. In addition, the Commission will continue to consider the issues arising out of the 1995 Annual Informational

Filing. The Commission's Staff is scheduled to file its testimony on March 24, 1998; Virginia Power's rebuttal is to be filed by April 27, 1998; and the reply testimony is to be filed by May 11, 1998. A public hearing is scheduled to commence on May 19, 1998.

Virginia Power's previous filings in this proceeding support maintaining the Company's rates at current levels; however, opposing parties have made filings recommending rate reductions in excess of $200 million. At this time, management cannot predict the ultimate outcome of the proceeding and its impact on the Company's results of operations, cash flows or financial position.

Retrospective Premium Assessments

Under several of the Company's nuclear insurance policies, the Company is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to these insurance companies. For additional information, see Note C to CONSOLIDATED FINANCIAL STATEMENTS.

Construction Program

The Company has made substantial commitments in connection with its construction program and nuclear fuel expenditures. Those expenditures are estimated to total $588.1 million (excluding AFC) for 1998. The Company presently estimates that all of its 1998 construction expenditures, including nuclear fuel, will be met through cash flow from operations.

Purchased Power Contracts

Since 1984, the Company has entered into contracts for the long-term purchases of capacity and energy from other utilities, qualifying facilities and independent power producers. The Company has 57 non-utility purchase contracts with a combined dependable summer capacity of 3,277 MW.

The table below reflects the Company's minimum commitments as of December 31, 1997, for power purchases from utility and non-utility suppliers.

Year	Commitment	
	Capacity	Other
	(Millions)	
1998	$ 813.5	$154.9
1999	816.7	156.7
2000	723.8	92.0
2001	716.0	83.7
2002	721.1	81.5
Later years	9,069.6	388.2
Total	$12,860.7	$957.0
Present value of the total	$ 5,878.0	$553.3

Payments made by Virginia Power in satisfaction of the minimum purchase commitments shown in the above table are subject to reduction or partial refund if (1) the non-utility suppliers fail to meet performance requirements or (2) changes in federal or state law or administrative actions disallow or have the effect of disallowing Virginia Power's recovery of such costs from its customers. The amount of such payment reductions or refunds, if any, will be determined and administered as provided in individual supply contracts, although (1) the deferral of refund obligations, (2) disputes over the applicability of such payment reductions or refund obligations and (3) the ability of some non-utility suppliers to make refunds could limit Virginia Power's ability to benefit from these contract provisions.

In addition to the minimum purchase commitments in the table above, under some of these contracts, the Company may purchase, at its option, additional power as needed. Actual payments for purchased power (including economy, emergency, limited term, short-term and other purchases for utility operations, as well as for trading purposes) for the years 1997, 1996 and 1995 were $1,381 million, $1,183 million and $1,093 million, respectively. For a discussion of the Company's efforts to restructure certain purchased power contracts, see Note O to CONSOLIDATED FINANCIAL STATEMENTS.

Fuel Purchase Commitments

The Company's estimated fuel purchase commitments for the next five years for system generation are as follows (millions): 1998 — $293; 1999 — $233; 2000 — $144; 2001 — $144; and 2002 — $127.

Sale of Power

The Company enters into agreements with other utilities and with other parties to purchase and sell capacity and energy. These agreements may cover current and future periods ("forward positions"). The volume of these transactions varies from day to day based on the market conditions, our current and anticipated load, and other factors. The combined amounts of sales and purchases range from 500 MW to 7,000 MW at various times during a given year. These operations are closely monitored from a risk management perspective.

Environmental Matters

The Company is subject to rising costs resulting from a steadily increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations of the Company. These costs have been historically recovered through the ratemaking process; however, should material costs be incurred and not recovered through rates, the Company's results of operations and financial condition could be adversely impacted.

Site Remediation

The EPA has identified the Company and several other entities as Potentially Responsible Parties (PRPs) at two Superfund sites located in Kentucky and Pennsylvania. The estimated future remediation costs for the sites are in the range of $61.5 million to $72.5 million. The Company's proportionate share of the cost is expected to be in the range of $1.7 million to $2.5 million, based upon allocation formulas and the volume of waste shipped to the sites. The Company has accrued a reserve of $1.7 million to meet its obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, the Company has determined that it is probable that the PRPs will fully pay the costs apportioned to them.

The Company and Dominion Resources have remedial action responsibilities remaining at two coal tar sites. The Company accrued a $2 million reserve to meet its estimated liability based on site studies and investigations performed at these sites. In addition, two civil actions have been instituted against the City of Norfolk and Virginia Power by property owners who allege that their property has been contaminated by toxic pollutants originating from one of the coal tar sites now owned by the City of Norfolk and formerly owned by the Company. The first civil action reached settlement without trial in September 1997. The remaining plaintiff is seeking compensatory damages of $2 million and punitive damages of $1 million. It is too early in this case for the Company to predict the outcome. The Company has filed answers denying liability. No trial date has been set.

The Company generally seeks to recover its costs associated with environmental remediation from third party insurers. At December 31, 1997, any pending or possible claims were not recognized as an asset or offset against recorded obligations of the Company.

R. Fair Value of Financial Instruments:

The Company used available market information and appropriate valuation methodologies to estimate the fair value of each class of financial instrument for which it is practicable to estimate fair value. These estimates are not necessarily indicative of the amounts the Company could realize in a market exchange. In addition, the use of different market assumptions may have a material effect on the estimated fair value amounts.

	December 31,			
	1997		1996	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Assets:				
Cash and cash equivalents	$ 36.0	$ 36.0	$ 47.9	$ 47.9
Nuclear decommissioning trust funds	569.1	569.1	443.3	443.3
Liabilities and capitalization:				
Short-term debt	226.2	226.2	312.4	312.4
Long-term debt:				
First and Refunding Mortgage Bonds	2,824.5	2,937.7	2,923.8	2,957.4
Medium-term notes	551.1	573.7	503.1	531.3
Money Market Municipal tax-exempt securities	488.6	488.6	488.6	488.6
Convertible interest rate tax-exempt bonds	10.0	10.4		
Preferred stock subject to mandatory redemption	180.0	186.6	180.0	185.8
Preferred securities of subsidiary trust	135.0	137.7	135.0	135.0

Cash and cash equivalents and short-term debt: The carrying amount of these items approximates fair value because of their short maturity.

Nuclear decommissioning trust funds: The fair value is based on available market information and generally is the average of bid and asked price.

First and Refunding Mortgage Bonds: Fair value is based on market quotations.

Medium-term notes: These notes were valued by discounting the remaining cash flows at a rate estimated for each issue. A yield curve rate was estimated to relate Treasury Bond rates for specific issues to the corresponding maturities.

Money Market Municipal tax-exempt securities: The interest rates for these notes vary so that fair value approximates carrying value.

Convertible interest rate tax-exempt bonds and preferred stock subject to mandatory redemption: The fair value is based on market quotations or is estimated by discounting the dividend and principal payments for a representative issue of each series over the average remaining life of the series.

Preferred securities of subsidiary trust: Fair value is based on market quotations.

S. Quarterly Financial Data (unaudited):

The following amounts reflect all adjustments, consisting of only normal recurring accruals (except as discussed below), necessary in the opinion of the management for a fair statement of the results for the interim periods.

Quarter	Revenues	Income from Operations	Net Income	Balance Available for Common Stock
		(Millions)		
1997				
1st	$1,174.8	$248.6	$110.3	$101.5
2nd	1,051.5	184.6	72.3	63.3
3rd	1,499.9	381.0	201.1	192.1
4th	1,352.8	205.1	85.4	76.5
1996				
1st	$1,169.7	$311.1	$152.8	$143.8
2nd	1,032.1	224.0	96.6	87.8
3rd	1,180.8	325.8	162.2	153.3
4th	1,038.3	149.1	45.7	36.9

Results for interim periods may fluctuate as a result of weather conditions, rate relief and other factors.

Certain accruals were recorded in 1997 and 1996 that are not ordinary, recurring adjustments, consisting of restructuring (see Note O to CONSOLIDATED FINANCIAL STATEMENTS) and accelerated cost recovery (see Note P to CONSOLIDATED FINANCIAL STATEMENTS).

Restructuring — The Company expensed $6.3 million, $1.4 million and $10.7 million during the second, third and fourth quarters of 1997, respectively, and $5.4 million, $19.3 million, $4.6 million and $35.6 million during the first, second, third and fourth quarters of 1996.

Accelerated cost recovery — Amounts reserved for accelerated cost recovery were $2.8 million, $28.3 million and $7.3 million during the second, third and fourth quarters of 1997, respectively, and $26.7 million during the fourth quarter of 1996.

Charges for restructuring and accelerated cost recovery reduced Balance Available for Common Stock by $5.8 million, $19.3 million, and $11.7 million for the second, third, and fourth quarters of 1997, respectively, and $3.5 million, $12.5 million, $3.0 million and $40.6 million for first, second, third and fourth quarters of 1996.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

On September 12, 1997, the Board of Directors elected Thos. E. Capps as Chairman, succeeding John B. Adams, Jr., who had held the position since 1994. Mr. Capps also is Chairman of the Board of Directors of Dominion Resources, Inc., the parent company of Virginia Power.

(a) Information concerning directors of Virginia Electric and Power Company is as follows:

Name and Age	Principal Occupation for Last 5 Years, Directorships in Public Corporations	Year First Elected a Director	Term Expires
Thos. E. Capps (62)	Chairman of the Board of Directors of Virginia Electric and Power Company from September 12, 1997 to date and Chairman, President and Chief Executive Officer of Dominion Resources from September 1, 1995 to date (from August 15, 1994 to September 1, 1995, Chairman and Chief Executive Officer; prior to August 15, 1994, Chairman, President and Chief Executive Officer). He is a Director of Bassett Furniture Industries, Inc. and NationsBank Corporation.	1986	2000
Norman Askew (55)	President and Chief Executive Officer of Virginia Electric and Power Company and Executive Vice President of Dominion Resources from August 1, 1997 to date; Executive Vice President of Dominion Resources and Chief Executive of East Midlands from February 21, 1997 to August 1, 1997; Chief Executive of East Midlands from April 1, 1994 to February 21, 1997; Managing Director prior to April 1, 1994.	1997	1998
John B. Adams, Jr. (53)	President and Chief Executive Officer of The Bowman Companies, Fredericksburg, Virginia, a manufacturer and bottler of alcohol beverages and he is a Director of Dominion Resources.	1987	1998
John B. Bernhardt (68)	Managing Director, Bernhardt/Gibson Financial Opportunities, financial services, Newport News, Virginia. He is a Director of Resource Bank and Dominion Resources.	1986	2000
James F. Betts (65)	Former Chairman of the Board and President, The Life Insurance Company of Virginia, Richmond, Virginia. He is a Director of Wachovia Corporation.	1978	2000
Jean E. Clary (53)	President and owner of Century 21 Clary and Associates, Inc., South Hill, Virginia.	1996	2000
John W. Harris (50)	President, The Harris Group, a real estate consulting firm, Charlotte, North Carolina. He is a Director of Piedmont Natural Gas Company, Inc. and US Airways Group, Inc.	1997	1998
Benjamin J. Lambert, III (61)	Optometrist, Richmond, Virginia. He is a Director of Consolidated Bank and Trust Company, Student Loan Marketing Association (SallieMae) and Dominion Resources.	1992	1998
Richard L. Leatherwood (58)	Retired, Baltimore, Maryland. Former President and Chief Executive Officer, CSX Equipment, an operating unit of CSX Transportation, Inc.). He is a Director of Dominion Resources and CACI International, Inc.	1994	1998
Harvey L. Lindsay, Jr. (68)	Chairman and Chief Executive Officer of Harvey Lindsay Commercial Real Estate, Norfolk, Virginia, a commercial real estate firm. He is a Director of Dominion Resources.	1986	1999
Kenneth A. Randall (70)	Corporate Director for various companies, Williamsburg, Virginia. He is a Director of Oppenheimer Funds, Inc., Kemper Insurance Companies and Prime Retail, Inc. He is a Director of Dominion Resources.	1971	1999

William T. Roos (69)	Retired, Hampton, Virginia (prior to December 31, 1993, President of Penn Luggage, Inc., retail specialty stores). He is a Director of Dominion Resources.	1975	1999
Frank S. Royal (58)	Physician, Richmond, Virginia. He is a Director of Columbia/HCA Healthcare Corporation, Crestar Financial Corporation, Chesapeake Corporation, CSX Corporation and Dominion Resources.	1997	1998
Judith B. Sack (49)	Senior Advisor, Morgan Stanley & Co., Inc., an investment banking firm, New York, New York, as of September 1, 1995 (prior to September 1, 1995, Advisor). She is a Director of Dominion Resources.	1997	1999
S. Dallas Simmons (58)	President of Virginia Union University, Richmond, Virginia. He is a Director of Dominion Resources.	1997	2000
Robert H. Spilman (70)	President, Spilman Properties, Basset, Virginia and Chairman of the Board and a Director of Jefferson-Pilot Corp., Greensboro, North Carolina. Retired Chairman and Chief Executive Officer of Bassett Furniture Industries, Inc. He is a Director of International Home Furnishing Center, The Pittston Company and Dominion Resources.	1994	2000
William G. Thomas (58)	President of Hazel & Thomas, Alexandria, Virginia, a law firm.	1987	1999
David A. Wollard (60)	Retired President, Bank One Colorado, N.A., Denver, Colorado.	1997	1999

The Directors are divided into three classes, with staggered terms. Each class consists, as nearly as possible, of one-third of the total number of Directors. Each Director holds office until the annual meeting for the year in which his class term expires, or until his successor is duly qualified and elected as provided in the Company's Articles of Incorporation.

Mr. Thomas has entered into a Consent Decree with the Office of Thrift Supervision in connection with the lending and credit granting activities of Perpetual Savings Bank, FSB, which Mr. Thomas formerly served as a director. The Consent Decree requires that Mr. Thomas obtain approval from the appropriate federal banking agency before accepting certain positions involving lending or credit activities with an insured depository institution.

(b) Information concerning the executive officers of Virginia Electric and Power Company is as follows:

Name and Age	Business Experience past Five Years
Norman Askew (55)	President and Chief Executive Officer of Virginia Electric and Power Company and Executive Vice President of Dominion Resources from August 1, 1997 to date; Executive Vice President of Dominion Resources and Chief Executive of East Midlands from February 21, 1997 to August 1, 1997; Chief Executive of East Midlands from April 1, 1994 to February 21, 1997; Managing Director prior to April 1, 1994.
Thomas F. Farrell, II (43)	Executive Vice President of Virginia Electric and Power Company and Senior Vice President-Corporate Affairs of Dominion Resources, September 1, 1997 to date; Senior Vice President-Corporate & General Counsel of Dominion Resources, January 1, 1997 to September 1, 1997; Vice President and General Counsel of Dominion Resources, July 1, 1995 to January 1, 1997; Partner in the law firm of McGuire, Woods, Battle, & Boothe LLP prior to July 1, 1995.
Robert E. Rigsby (48)	Executive Vice President, January 1, 1996 to date; Senior Vice President-Finance and Controller, January 1, 1995 to January 1, 1996; Vice President-Human Resources prior to January 1, 1995.
William R. Cartwright (55)	Senior Vice President-Fossil and Hydro, July 1, 1995 to date; Vice President Fossil and Hydro prior to July 1, 1995.
Lawrence E. De Simone (50)	Senior Vice President-Energy Services, July 15, 1996 to date; vice president-strategic planning for Central & South West Corp., a Dallas-based electric utility holding company, prior to July 15, 1996.
Larry M. Girvin (54)	Senior Vice President-Commercial Operations, January 1, 1996 to date; Vice President-Human Resources, January 1, 1995 to January 1, 1996; Vice President-Nuclear Services prior to January 1, 1995.
James P. O'Hanlon (54)	Senior Vice President-Nuclear, June 1, 1994 to date; Vice President-Nuclear Operations prior to June 1, 1994.

John A. Shaw (49)	Senior Vice President-Finance, March 16, 1998 to date; Vice President Financial Service for ARCO Chemical Company, Philadelphia, Pennsylvania, prior to March 16, 1998. During the past 5 years, he has also served as Treasurer and Controller of ARCO Chemical.
Eva S. Teig (53)	Senior Vice President-External Affairs & Corporate Communications, September 1, 1997 to date; Vice President-External Affairs & Corporate Communications, June 1, 1997 to September 1, 1997; Vice President-Public Affairs prior to June 1, 1997.
Said Ziai (44)	Senior Vice President-Corporate Strategy, October 1,1997 to date; Corporate Planning Director, East Midlands Electricity plc, Nottingham, England prior to October 1, 1997.
Thomas L. Caviness, Jr. (52)	Vice President-Retail Energy Services, July 1, 1995 to date;Vice President-Eastern Division prior to July 1, 1995.
David A. Christian (43)	Site Vice President-Surry, March 1, 1998 to date; Station Manager-Surry Power Station, September 1, 1994 to March 1, 1998; Assistant Station Manager-Surry, prior to September 1, 1994.
J. Kennerly Davis, Jr. (52)	Vice President-Finance and Administrative Services, Treasurer and Corporate Secretary, January 1, 1996 to date; Vice President, Treasurer and Corporate Secretary, October 1, 1994 to January 1, 1996; Vice President and Corporate Secretary of Dominion Resources prior to October 1, 1994.
James T. Earwood, Jr. (54)	Vice President-Bulk Power Delivery, January 1, 1997 to date;Vice President-Energy Efficiency and Division Services, January 1, 1996 to January 1, 1997; Vice President-Division Services prior to January 1, 1996.
E. Paul Hilton (54)	Vice President-Regulation, October 1, 1997 to date; Manager, Rates and Regulation, February 20, 1996 to October 1, 1997; Manager, Rates prior to February 20, 1996.
Thomas A. Hyman, Jr. (46)	Vice President-Distribution Operations and North Carolina Power, June 1, 1997 to date;Vice President-Eastern Division and North Carolina Power, July 1, 1995 to June 1, 1997; Vice President-Southern Division, June 1, 1994 to July 1, 1995; Station Manager-Bremo Power Station prior to June 1, 1994.
Michael R. Kansler (43)	Vice President-Nuclear Operations, January 1, 1997 to date;Vice President-Nuclear Engineering and Services, October 1, 1995 to January 1, 1997; Vice President-Nuclear Services, January 1, 1995 to October 1, 1995 ; Manager-Nuclear Operations Support, September 1, 1994 to January 1, 1995; Station Manager-Surry Nuclear Power Station prior to September 1, 1994.
William R. Matthews (51)	Site Vice President-North Anna, March 1, 1998 to date; Station Manager-North Anna Power Station, May 1, 1996 to March 1, 1998; Assistant Station Manager-North Anna Power Station, December 1, 1993 to May 1, 1996; Superintendent-Maintenance, prior to December 1, 1993.
Mark F. McGettrick (40)	Vice President-Customer Service, January 1, 1997 to date; Corporate Restructuring Project Manager, February 1, 1995 to January 1, 1997; Assistant Controller prior to February 1, 1995.
William S. Mistr (50)	Vice President-Information Technology, January 1, 1996 to date and Vice President of Dominion Resources, February 20, 1997 to date; Vice President and Treasurer, Dominion Energy, Inc., October 1, 1994 to January 1, 1996; Assistant Treasurer, Dominion Resources prior to October 1, 1994.
Thomas J. O'Neil (55)	Vice President-Human Resources, January 1, 1996 to date; Vice President-Energy Efficiency prior to January 1, 1996.
Edward J. Rivas (53)	Vice President-Fossil & Hydro Operations, January 1, 1998 to date; Manager-Clover Power Station, March 16, 1994 to January 1, 1998; Manager-Fossil & Hydro Training prior to March 16, 1994.
Robert F. Saunders (54)	Vice President-Nuclear Engineering and Services, January 1, 1997 to date; Vice President-Nuclear Operations, June 1, 1994 to January 1, 1997; Assistant Vice President-Nuclear Operations, prior to June 1, 1994.
Johnny V. Shenal (52)	Vice President-Distribution Construction, June 1, 1997 to date;Vice President-Northern and Western Divisions, June 1, 1994 to June 1, 1997; Vice President-Western Division, prior to June 1, 1994.
Richard T. Thatcher (48)	Vice President-Wholesale Power Group, September 1, 1997 to date; Managing Director, Wholesale Power, April 10, 1997 to September 1, 1997; Manager, Wholesale Power Group, July 1, 1995 to April 10, 1997; Project Manager, January 1, 1995 to July 1, 1995; Director-Generation and Interconnection Planning prior to January 1, 1995.

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

Section 16(a) Beneficial Ownership Reporting Compliance

Our Directors and Executive Officers report their ownership of our preferred stock pursuant to Section 16(a) of the Exchange Act. Through administrative oversight, the following individuals failed to file their initial statements of beneficial ownership on Form 3 on a timely basis: Thos. E. Capps, Norman Askew, John B. Bernhardt, John W. Harris, Kenneth A. Randall, Frank S. Royal, Judith B. Sack, S. Dallas Simmons, David A. Wollard, Thomas F. Farrell, II, Said Ziai, E. Paul Hilton, Richard T. Thatcher, David A. Christian and William R. Matthews.

None of the individuals owned any of our preferred stock at the time their initial reports should have been filed nor have they or any other Director or Executive Officer have any reportable transactions in the preferred stock which have not been reported. The required filings have now been made.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Table

The Summary Table below includes compensation paid by the Company for services rendered in 1997, 1996 and 1995 for the Chief Executive Officer and the four other most highly compensated executive officers (as of December 31, 1997) as determined by total salary and incentive payments for 1997.

Summary Compensation Table

		Annual Compensation			Long Term Compensation Awards		Payouts	
Name & Principal Position	Year	Salary	Incentive(1)	Other Annual Compensation(2)	Restricted Stock Awards	Securities Underlying Options/ SAR Grants	LTIP Pay out	All Other Compensation(3)
James T. Rhodes	1997	$244,800	$159,250(4)	$ 0	$ 0	$0	$803,429(5)	$7,977,039(6)
President and CEO	1996	$410,575	$247,606	$ 0	$ 0	$0	$ 75,684	$ 4,500
(retired August 1, 1997)	1995	$406,075	$273,000	$ 0	$ 0	$0	$ 77,970	$ 4,500
Norman Askew President and CEO (effective August 1, 1997)	1997	$177,084	$ 85,833	$14,560	$ 0(7)	$0	$ 18,791(8)	$ 120,000(9)
Robert E. Rigsby	1997	$254,850	$129,920	$ 0	$ 0(10)	$0	$ 83,171(11)	$ 4,800
Executive Vice President	1996	$226,469	$143,892	$ 0	$ 0	$0	$ 43,157	$ 4,500
	1995	$171,456	$105,000	$ 0	$ 0	$0	$ 34,569	$ 4,500
James P. O'Hanlon	1997	$270,250	$110,240	$ 0	$ 0(12)	$0	$ 80,140(13)	$ 4,800
Senior Vice President —	1996	$220,815	$128,511	$ 0	$ 0	$0	$ 56,152	$ 4,500
Nuclear	1995	$207,555	$136,400	$ 0	$ 0	$0	$ 45,109	$ 4,500
Lawrence E. DeSimone	1997	$212,751	$ 85,520	$ 0	$ 0(14)	$0	$ 0	$ 3,180
Senior Vice President — Energy Services	1996	$ 94,419	$ 50,441	$ 0	$ 0	$0	$ 0	$ 0
Larry M. Girvin	1997	$187,050	$ 85,520	$ 0	$ 0(15)	$0	$ 52,935(16)	$ 4,800
Senior Vice President —	1996	$164,600	$ 89,200	$ 0	$ 0	$0	$ 30,717	$ 4,500
Commercial Operations	1995	$139,650	$ 66,606	$ 0	$ 0	$0	$ 24,685	$ 4,500

(1) The Company does not maintain "bonus" plans which are used by some companies to supplement salaries based on the success of the company without regard to individual performance. However, the Company has in place various incentive plans that compensate officers and employees for achieving specified performance goals.

(2) Unless noted, none of the executive officers above received perquisites or other personal benefits in excess of either $50,000 or 10% of total salary and incentive payment.

(3) Employer matching contribution of $4,800 on Employee Savings Plan contributions, unless otherwise noted.

(4) Amount represents a lump sum settlement of his rights under the 1997 Annual Incentive Plan.

(5) $158,025 was paid under the 1995-1997 Performance Achievement Plan. 7,326 shares of Dominion Resources, Inc. Common Stock (worth $269,231 @ $36.75 per share) were issued under the 1996-1998 Long Term Incentive Plan. 10,326 shares of Dominion Resources, Inc. Common Stock (worth $376,173 @ $36.75 per share) were issued under the 1997-1999 Long Term Incentive Plan.

(6) Upon his retirement, Dr. Rhodes received the following payments from the Company: $51,078 for unused vacation; $1,023,271 as provided by his employment contract; $4,184,220 lump sum settlement of pension benefits not payable from the qualified retirement plan; $2,715,926 as a lump sum settlement of his benefit under the Executive Supplemental Retirement Plan, and $2,544 in employer match on Employee Savings Plan contributions.

(7) Mr. Askew held no restricted stock as of 12/31/97.

(8) Amount represents incentive plan pay outs from Virginia Power, on a prorated basis, for performance cycles that ended in 1997: $7,550 in lieu of dividends on restricted stock for partial participation in the 1996-1998 and the 1997-1999 performance cycles; and $11,241 for the 1995-1997 performance cycle.

(9) A one time payment related to his international transfer from the UK to the US.

(10) Aggregate number of shares of restricted stock on December 31, 1997: 13,763 with an aggregate value of $585,788 (based on a closing price on December 31, 1997 of $42.5625 per share).

(11) 2,085 shares of stock, with 50% of the value awarded in cash ($41,133) and the remaining 1,042 shares being issued (valued at $42,038 or $40.3437 per share as of 2/20/98).

(12) Aggregate number of shares of restricted stock on December 31, 1997: 9,773 with aggregate value of $415,963 (closing price on December 31, 1997 of $42.5625 per share).

(13) 2,009 shares of stock, with 50% of the value awarded in cash ($39,635) and the remaining 1,004 shares being issued (valued at $40,505 or $40.3437 per share as of 2/20/98).

(14) Mr. DeSimone held no restricted stock as of 12/31/97.

(15) Aggregate number of shares of restricted stock on December 31, 1997: 7,528 with aggregate value of $320,411 (closing price on December 31, 1997 of $42.5625 per share).

(16) 1,327 shares of stock, with 50% of the value awarded in cash ($26,187) and the remaining 663 shares being issued (valued at $26,748 or $40.3437 per share as of 2/20/98).

Long-term Incentive Compensation

Long-term incentive awards made during 1997 are shown in the following table.

Long-term Incentive Plans — Awards in the Last Fiscal Year
1997-1999 Long-term Incentive Plan

Name	Number of Shares, Units or Other Rights(#)	Performance or Other Period until Maturation or Payout	Estimated Future Payouts under Non-stock Price Based Plans	
			Threshold ($ or #)	Target ($ or #)
J.T. Rhodes	$259,448	3 years	$129,724	$259,448
N. Askew	$261,250	3 years	$130,625	$261,250
J.P. O'Hanlon	$112,843	3 years	$ 56,422	$112,843
R.E. Rigsby	$163,714	3 years	$ 81,857	$163,714
L.E. DeSimone	$ 87,750	3 years	$ 43,875	$ 87,750
L.M. Girvin	$ 87,750	3 years	$ 43,875	$ 87,750

Retirement Plans

The table below sets forth the estimated annual straight life benefit that would be paid following retirement under the benefit formula of the Dominion Resources, Inc. Retirement Plan (the Retirement Plan).

Estimated Annual Benefits Payable upon Retirement

	Credited Years of Service			
Final Average Earnings	15	20	25	30
$185,000	$51,501	$68,668	$85,836	$103,003
200,000	56,069	74,758	93,448	112,138
225,000	63,681	84,908	106,136	127,363
250,000	71,294	95,058	118,823	142,588
300,000	86,519	115,358	144,198	173,038
350,000	101,744	135,658	169,573	203,488
400,000	116,969	155,958	194,948	233,938
450,000	132,194	176,258	220,323	264,388
500,000	147,419	196,558	245,698	294,838
550,000	162,644	216,858	271,073	325,288
600,000	177,869	237,158	296,448	355,738
650,000	193,094	257,458	321,823	386,188
750,000	223,544	298,058	372,573	447,088

Benefits under the Retirement Plan are based on (i) average base compensation over the consecutive 60-month period in which pay is highest, (ii) years of credited service, (iii) age at retirement, and (iv) the offset of Social Security Benefits.

Certain officers have entered into retirement agreements that give additional credited years of service for retirement and retirement life insurance purposes, and retirement medical benefit purposes contingent upon the officer reaching a specified age and remaining in the employ of the Company or an affiliate.

For purposes of the above table, based on 1997 compensation, credited years of service (including any additional years earned in connection with the retirement agreements) for each of the individuals named in the cash compensation table would be as follows:

James T. Rhodes: 30; Norman Askew: 0; Robert E. Rigsby: 26; James P. O'Hanlon: 8; Lawrence E. De Simone: 0; Larry M. Girvin: 31.

Virginia Power's executive compensation program has placed increased emphasis on incentive compensation opportunities linked to financial and operating performance. Base salaries have been held below the mean for comparable positions at comparable companies. The Retirement Plan benefit formula recognizes base salary, but not incentive compensation payments. Therefore, each year the Organization and Compensation Committee approves a market-based adjustment to executive base salaries for use in calculating the retirement benefit under the Dominion Resources, Inc. Benefit Restoration Plan (the Restoration Plan). In 1997, this adjustment was 11 percent. Also, the Internal Revenue Code limits the annual retirement benefit that may be paid from a qualified retirement plan and the amount of compensation that may be recognized by the Retirement Plan. To the extent that benefits determined under the Retirement Plan's benefit formula exceed the limitations imposed by the Internal Revenue Code, they will be paid under the Dominion Resources, Inc. Benefit Restoration Plan.

The Company also provides an Executive Supplemental Retirement Plan (the Supplemental Plan) to its elected officers designated to participate by the Board of Directors. The Supplemental Plan provides an annual retirement benefit equal to 25 percent of a participant's final compensation (base pay plus annual incentive plan payments). The normal form of benefit is monthly installments for 120 months to a participant with 60 months of service, who (i) retires at or after age 55 from the employ of the Company, (ii) has become permanently disabled, or (iii) dies. The accrued benefit vests proportionately between the time an officer is elected and when he or she reaches age 55 when the benefit is fully vested If a participant dies while employed, the normal form of benefit will be paid to a designated beneficiary. If a participant dies while retired, but before receiving all benefit payments, the remaining installments will be paid to a designated beneficiary. A lump sum payment is available under certain conditions.

Based on 1997 compensation, the estimated annual retirement benefit for each of the executive officers under the Supplemental Plan would be as follows: N. Askew: $167,406; R.E. Rigsby: $104,345; J.P. O'Hanlon: $113,228; L.E. De Simone: $79,139; L.M. Girvin: $73,764.

Retirement Benefit Funding Plan

The Company maintains a Retirement Benefit Funding Plan to provide a means to secure obligations under the Supplemental Plan, the Restoration Plan, and retirement agreements. The Retirement Benefit Funding Plan does not provide any additional benefits; it simply helps secure the funding for these benefit obligations. The amount payable by Virginia Power under the Supplemental Plan, the Restoration Plan and retirement agreements is reduced, on a dollar-for-dollar basis, by the funds available under the Retirement Benefit Funding Plan.

Employment Agreements

The Company has entered into employment continuity agreements (the Agreements) with its key management executives, including, Norman Askew, Robert E. Rigsby, James P. O'Hanlon, Lawrence E. De Simone, and Larry M. Girvin, which provide benefits in the event of a change in control. Each Agreement has a three-year term and thereafter is automatically extended on its anniversary date for an additional year unless notified that the Agreement will not be extended by the Company. If, following a change in control (as defined in the Agreements) of Dominion Resources or the Company, an executive's employment is terminated by the Company without cause, or voluntarily by the executive within sixty days after a material reduction in the executive's compensation, benefits or responsibilities, the Company will be obligated to pay to the executive continued compensation equaling the average base salary and cash incentive bonuses for the thirty-six full month period of employment preceding the change in control or employment termination. In addition, the terminated executive will continue to be entitled to any benefits due under any stock or benefit plans. The Agreements do not alter the compensation and benefits available to an executive whose employment with the Company continues for the full term of the executive's Agreement. The amount of benefits provided under each executive's Agreement will be reduced by any compensation earned by the executive from comparable employment by another employer during the thirty-six months following termination of employment with the Company. An executive shall not be entitled to the above benefits in the event termination is for cause.

Compensation of Directors

The non-employee members of the Board receive an annual retainer of $19,000 and a fee of $900 for each Board or committee meeting attended. Committee chairmen receive an additional annual retainer of $3,000. Consistent with the Company's philosophy concerning equity-based compensation for officers, effective in 1998 non-employee directors will also receive an annual retainer in Dominion Resources common stock valued at $19,000. These Directors may elect to defer their annual retainer and/or their meeting fees under the Deferred Compensation Plan until they retire from the Board or otherwise direct. The deferred fees are credited, for bookkeeping purposes, with earnings and losses as if they were invested in either an interest bearing account or Dominion Resources Common Stock, depending on the Director's election.

Directors Charitable Contribution Program

Dominion Resources administers a Directors' Charitable Contribution Program (the Program) that covers Directors of the Company, as part of its overall program of charitable giving. Beginning at the death of a Director a donation in an aggregate amount of $50,000 per year for 10 years will be made to one or more qualifying charitable organizations recommended by the individual Director. Life insurance policies have been purchased on the lives of the Directors in connection with the Program. These policies are owned by Dominion Resources, which is also the beneficiary. The Directors derive no financial or tax benefits from the Program.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The table below sets forth as of February 20, 1998, except as noted, the number of shares of Common Stock of Dominion Resources owned by Directors and four other more highly compensated executive officers of Virginia Electric and Power Company.

Name	Shares of Common Stock Beneficially Owned	Director Plan Accounts(1)
John B. Adams, Jr.	3,891	9,091
John B. Bernhardt	1,500	9,091
James F. Betts	7,500	9,091
Thos. E. Capps	44,914(2)	
Jean E. Clary	116	9,162
John W. Harris	500	9,091
Benjamin J. Lambert, III	90	10,212
Richard L. Leatherwood	1,000	17,616
Harvey L. Lindsay	400	9,091
Kenneth A. Randall	3,027	9,091
William T. Roos	14,603(3)	9,091
Frank S. Royal		10,430
Judith B. Sack	1,000	14,575
S. Dallas Simmons	650	13,370
Robert H. Spilman	1,187	9,091
William G. Thomas	1,000	13,257
David A. Wollard		9,879
Norman Askew	1,290(2)	
Lawrence E. De Simone	92	
Larry M. Girvin	7,654	
James P. O'Hanlon	11,100	
Robert E. Rigsby	22,079	
All Directors and Executive Officers as a group — 41 persons (4)	397,599(2)(5)	

(1) Amounts in this column represent share equivalents accumulated under the non-employee director Stock Accumulation Plan. Balances of 9,091 shares are the amounts accumulated thus far under the plan. Because of the plan's vesting provisions, these amounts will not necessarily be distributed to a director. Any balance in excess of 9,091 is an amount of shares accumulated-at the director's election-under the Deferred Cash Compensation plan. That excess amount will be distributed in actual shares to the director.

(2) Amounts include restricted stock as follows: Mr. Capps — 23,984 shares; Mr. Askew — 1,290; and all directors and executive officers as a group — 89,859.

(3) Mr. Roos disclaims beneficial ownership of 4,387 shares that are held in trusts for family members.

(4) All current directors and executive officers as a group own less than one percent of the number of shares outstanding as of February 20, 1998.

(5) Beneficial ownership is disclaimed for a total of 4,786 shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Hazel & Thomas, a professional corporation, from time to time acts as counsel to the Company. Mr. Thomas, a Director of the Company, is a shareholder of Hazel & Thomas.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this Form 10-K:

1. Financial Statements

See Index on page 21.

2. Exhibits

3.1	—	Restated Articles of Incorporation, as amended, as in effect on September 12, 1994 (Exhibit 3(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference).
3.2	—	Bylaws, as amended, as in effect on October 17, 1997 (Exhibit 3(ii), Form 10-Q for the period ended September 30, 1997, File No. 1-2255, incorporated by reference).
4.1	—	See Exhibit 3 (i) above.
4.2	—	Indenture of Mortgage of the Company, dated November 1, 1935, as supplemented and modified by fifty-eight Supplemental Indentures (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255, incorporated by reference); Fifty-Ninth Supplemental Indenture (Exhibit 4(ii), Form 10-Q for the quarter ended March 31, 1986, File No. 1-2255, incorporated by reference); Sixtieth Supplemental Indenture (Exhibit 4(ii), Form 10-Q for the quarter ended September 30, 1986, File No. 1-2255, incorporated by reference); Sixty-First Supplemental Indenture (Exhibit 4(ii), Form 8-K, dated June 2, 1987, File No. 1-2255, incorporated by reference); Sixty-Second Supplemental Indenture (Exhibit 4(i), Form 8-K, dated November 3, 1987, File No. 1-2255, incorporated by reference); Sixty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 8, 1988, File No. 1-2255, incorporated by reference); Sixty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 8, 1989, File No. 1-2255, incorporated by reference); Sixty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 22, 1989, File No. 1-2255, incorporated by reference); Sixty-Sixth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 27, 1990, File No. 1-2255, incorporated by reference); Sixty-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 2, 1991, File No. 1-2255, incorporated by reference); Sixty-Eighth Supplemental Indenture (Exhibit 4(i)), Sixty-Ninth Supplemental Indenture (Exhibit 4(ii)) and Seventieth Supplemental Indenture (Exhibit 4(iii), Form 8-K, dated February 25, 1992, File No. 1-2255, incorporated by reference); Seventy-First Supplemental Indenture (Exhibit 4(i)) and Seventy-Second Supplemental Indenture (Exhibit 4(ii), Form 8-K, dated July 7, 1992, File No. 1-2255, incorporated by reference); Seventy-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 6, 1992, File No. 1-2255, incorporated by reference); Seventy-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 6, 1993, File No. 1-2255, incorporated by reference); Seventy-Sixth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated April 21, 1993, File No. 1-2255, incorporated by reference); Seventy-Seventh Supplemental Indenture (Exhibit 4(i), Form 8-K, dated June 8, 1993, File No. 1-2255, incorporated by reference); Seventy-Eighth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Seventy-Ninth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated August 10, 1993, File No. 1-2255, incorporated by reference); Eightieth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 12, 1993, File No. 1-2255, incorporated by reference); Eighty-First Supplemental Indenture (Exhibit 4(iii), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference); Eighty-Second Supplemental Indenture (Exhibit 4(i), Form 8-K, dated January 18, 1994, File No. 1-2255, incorporated by reference); Eighty-Third Supplemental Indenture (Exhibit 4(i), Form 8-K, dated October 19, 1994, File No. 1-2255, incorporated by reference); Eighty-Fourth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated March 22, 1995, File No. 1-2255, incorporated by reference; and Eighty-Fifth Supplemental Indenture (Exhibit 4(i), Form 8-K, dated February 20, 1997, File No. 1-2255, incorporated by reference).

4.3	—	Indenture, dated April 1, 1985, between Virginia Electric and Power Company and Crestar Bank (formerly United Virginia Bank) (Exhibit 4(iv), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.4	—	Indenture, dated as of June 1, 1986, between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank) (Exhibit 4(v), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.5	—	Indenture, dated April 1, 1988, between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank), as supplemented and modified by a First Supplemental Indenture, dated August 1, 1989, (Exhibit 4(vi), Form 10-K for the fiscal year ended December 31, 1993, File No. 1-2255, incorporated by reference).
4.6	—	Subordinated Note Indenture, dated as of August 1, 1995 between Virginia Electric and Power Company and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, as supplemented (Exhibit 4(a), Form S-3 Registration Statement File No. 333-20561 as filed on January 28, 1997, incorporated by reference).
4.7	—	Virginia Electric and Power Company agrees to furnish to the Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized thereunder does not exceed 10 percent of Virginia Electric and Power Company's total assets.
10.1	—	Operating Agreement, dated June 17, 1981, between Virginia Electric and Power Company and Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and Allegheny Generating Company (Exhibit 10(vi), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.2	—	Purchase, Construction and Ownership Agreement, dated as of December 28, 1982 but amended and restated on October 17, 1983, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(viii), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.3	—	Amended and Restated Interconnection and Operating Agreement, dated as of July 29, 1997 between Virginia Electric and Power Company and Old Dominion Electric Cooperative (filed herewith).
10.4	—	Nuclear Fuel Agreement, dated as of December 28, 1982 as amended and restated on October 17, 1983, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(x), Form 10-K for the fiscal year ended December 31, 1983, File No. 1-8489, incorporated by reference).
10.5	—	Credit Agreements dated June 7, 1996, between The Chase Manhattan Bank (formerly Chemical Bank) and Virginia Electric and Power Company (Exhibits 10(i) and 10(ii), Form 10-Q for the period ended June 30, 1996, File No. 1-2255, incorporated by reference).
10.6	—	Credit Agreement, dated December 1, 1985, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xix), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-8489, incorporated by reference).
10.7	—	Agreement for Northern Virginia Services, dated as of November 1, 1985, between Potomac Electric Power Company and Virginia Electric and Power Company (Exhibit 10(xxi), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-8489, incorporated by reference).
10.8	—	Purchase, Construction and Ownership Agreement, dated May 31, 1990, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xi), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.9	—	Operating Agreement, dated May 31, 1990, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.10	—	Coal-Fired Unit Turnkey Contract (Volume 1), dated April 6, 1989, and the Unit 2 Amendment (Volume 1), dated May 31, 1990 between Virginia Electric and Power Company and Old Dominion Electric Cooperative, Westinghouse, Black & Veatch, Combustion Engineering and H. B. Zachry (Volumes 2-11 contain technical specifications) (Exhibit 10(xiii), Form 10-K for the fiscal year ended December 31, 1990, File No. 1-2255, incorporated by reference).
10.11*	—	Description of arrangements with certain officers regarding additional credited years of service for retirement purposes (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1992, File No. 1-2255, incorporated by reference).

10.12*	—	Dominion Resources, Inc. Directors' Deferred Compensation Plan effective July 1, 1986, as amended and restated on January 1, 1996 (Exhibit 10(xii), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.13*	—	Dominion Resources, Inc. Performance Achievement Plan, effective January 1, 1986, as amended and restated effective February 19, 1988 (Exhibit 10(xxiii), Form 10-K for the fiscal year ended December 31, 1994, File No. 1-2255, incorporated by reference).
10.14*	—	Dominion Resources, Inc. Executive Supplemental Retirement Plan, effective January 1, 1981 as amended and restated September 1, 1996 with first amendment dated June 20, 1997 and second amendment dated March 3, 1998 (filed herewith).
10.15*	—	Dominion Resources, Inc.'s Cash Incentive Plan as adopted December 20, 1991 (Exhibit 10(xxv), Form 10-K for the fiscal year ended December 31, 1994, File No. 1-2255, incorporated by reference).
10.16*	—	Dominion Resources, Inc. Retirement Benefit Funding Plan, effective June 29, 1990 as amended and restated September 1, 1996 (filed herewith).
10.17*	—	Dominion Resources, Inc. Retirement Benefit Restoration Plan as adopted effective January 1, 1991 as amended and restated September 1, 1996 (filed herewith).
10.18*	—	Dominion Resources, Inc. Executives' Deferred Compensation Plan, effective January 1, 1994, as amended and restated on January 1, 1997 (Exhibit 10(xix), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.19*	—	Form of an Employment Agreement dated June 23, 1994 between Virginia Power and certain executive officers (Exhibit 10(xxi), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.20*	—	Employment Agreement dated September 15, 1995 between Virginia Power and Robert E. Rigsby (Exhibit 10(xxii), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.21*	—	Employment Agreement dated February 21, 1997 between Dominion Resources and Norman Askew (filed herewith).
10.22*	—	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, effective April 23, 1996 (Exhibit 10(xxiv), Form 10-K for the fiscal year ended December 31, 1996, File No. 1-2255, incorporated by reference).
10.23*	—	Dominion Resources, Inc. Incentive Compensation Plan, effective April 22, 1997 (filed herewith)
23.1	—	Consent of Hunton & Williams (filed herewith).
23.2	—	Consent of Jackson & Kelly (filed herewith).
23.3	—	Consent of Deloitte & Touche LLP (filed herewith).
27	—	Financial Data Schedule (filed herewith).

* Indicates management contract or compensatory plan or arrangement

(b) Reports on Form 8-K

None

SIGNATURES

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

VIRGINIA ELECTRIC AND POWER COMPANY

Date: March 20, 1998

By THOS. E. CAPPS
(Thos. E. Capps., Chairman of the Board of Directors)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 20, 1998.

Signature	Title
THOS E. CAPPS **Thos E. Capps**	Chairman of the Board of Directors and Director
JOHN B. ADAMS, JR. **John B. Adams, Jr.**	Director
NORMAN ASKEW **Norman Askew**	President (Chief Executive Officer) and Director
JOHN B. BERNHARDT **John B. Bernhardt**	Director
JAMES F. BETTS **James F. Betts**	Director
JEAN E. CLARY **Jean E. Clary**	Director
JOHN W. HARRIS **John W. Harris**	Director
BENJAMIN J. LAMBERT, III **Benjamin J. Lambert, III**	Director
RICHARD L. LEATHERWOOD **Richard L. Leatherwood**	Director
HARVEY L. LINDSAY, JR. **Harvey L. Lindsay, Jr.**	Director

Signature	Title
Kenneth A. Randall	Director
WILLIAM T. ROOS William T. Roos	Director
FRANK S. ROYAL Frank S. Royal	Director
JUDITH B. SACK Judith B. Sack	Director
S. DALLAS SIMMONS S. Dallas Simmons	Director
ROBERT H. SPILMAN Robert H. Spilman	Director
WILLIAM G. THOMAS William G. Thomas	Director
David A. Wollard	Director
M. S. BOLTON, JR. M. S. Bolton, Jr.	Controller (Principal Accounting Officer)