HELD GERALD
Form 4
June 21, 2010

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL
OMB Number: 3235-0287
Expires: January 31, 2005
Estimated average burden hours per response... 0.5

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
HELD GERALD
(Last) (First) (Middle)
18700 VISTA DE ALMADEN
(Street)
SAN JOSE, CA 95134
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
INFORMATICA CORP [INFA]

3. Date of Earliest Transaction (Month/Day/Year)
06/15/2010

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
__X__ Director
_____ 10% Owner
_____ Officer (give title below)
_____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	06/15/2010		A		1,667 (1) (2)	A	$ 0	1,667	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amou Underlying Securi (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amo or Num of S
Non-qualified stock option (right to buy)	$ 26.82	06/15/2010		A		15,000		06/15/2011	06/15/2017	Common Stock	15,

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
HELD GERALD 18700 VISTA DE ALMADEN SAN JOSE, CA 95134	X			

Signatures

/s/Peter McGoff Attorney-in-fact for Gerald Held	06/21/2010
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The shares subject to these restricted stock units shall become fully vested as of the first anniversary of the Grant Date, assuming continued service with the Company on the first anniversary of the Grant Date. For the purposes of the restricted stock unit grants, the Grant Date is 6/15/2010.

(2) These securities are restricted stock units. Each unit represents the Reporting Person's right to receive one share of Common Stock, subject to the applicable vesting schedule.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. #000000"> **680** 810

Total investments

3,501 3,168 **Property, Plant and Equipment**

Property, plant and equipment

42,063 38,663

Accumulated depreciation, depletion and amortization

(13,123) (11,947)

Total property, plant and equipment, net

28,940 26,716 **Deferred Charges and Other Assets**

Goodwill

4,298 4,298

Prepaid pension cost

1,915 1,947

Derivative assets

1,915 705

Regulatory assets

758 788

Other

1,204 702

Total deferred charges and other assets

10,090 8,440

Total assets

$52,660 $45,418

4

At December 31, (millions)	**2005**	2004
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Securities due within one year	**$ 2,330**	$ 1,368
Short-term debt	**1,618**	573
Accounts payable	**2,756**	1,956
Accrued interest, payroll and taxes	**694**	578
Derivative liabilities	**6,087**	2,858
Other	**995**	695
Total current liabilities	**14,480**	8,028
Long-Term Debt		
Long-term debt	**13,237**	14,078
Junior subordinated notes payable to affiliated trusts	**1,416**	1,429
Total long-term debt	**14,653**	15,507
Deferred Credits and Other Liabilities		
Deferred income taxes	**4,926**	5,424
Deferred investment tax credits	**58**	75
Asset retirement obligations	**2,249**	1,705
Derivative liabilities	**3,971**	1,583
Regulatory liabilities	**607**	610
Other	**1,062**	803
Total deferred credits and other liabilities	**12,873**	10,200
Total liabilities	**42,006**	33,735
Commitments and Contingencies (see Note 23)		
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	**257**	257
Common Shareholders Equity		
Common stock no par(1)	**11,286**	10,888
Other paid-in capital	**125**	92
Retained earnings	**1,550**	1,442
Accumulated other comprehensive loss	**(2,564)**	(996)
Total common shareholders equity	**10,397**	11,426
Total liabilities and shareholders equity	**$ 52,660**	$ 45,418

(1) 500 million shares authorized; 347 million shares and 340 million shares outstanding at December 31, 2005 and December 31, 2004, respectively.

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

Consolidated Statements of Common Shareholders   Equity and Comprehensive Income

(millions)	Common Stock Shares	Common Stock Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2002	308	$ 9,051	$ 47	$ 1,561	$ (446)	$ 10,213
Comprehensive income:						
Net income				318		318
Net deferred derivative losses hedging activities, net of $479 tax benefit					(791)	(791)
Unrealized gains on investment securities, net of $78 tax expense					112	112
Foreign currency translation adjustments					68	68
Amounts reclassified to net income:						
Net realized losses on investment securities, net of $29 tax benefit					49	49
Net derivative losses hedging activities, net of $225 tax benefit					379	379
Total comprehensive income				318	(183)	135
Issuance of stock public offering	11	683				683
Issuance of stock employee and direct stock purchase plans	3	206				206
Stock awards and stock options exercised (net of change in unearned compensation)	3	112				112
Tax benefit from stock awards and stock options exercised			14			14
Dividends				(825)		(825)
Balance at December 31, 2003	325	10,052	61	1,054	(629)	10,538
Comprehensive income:						
Net income				1,249		1,249
Net deferred derivative losses hedging activities, net of $632 tax benefit					(1,118)	(1,118)
Unrealized gains on investment securities, net of $18 tax expense					37	37
Foreign currency translation adjustments					30	30
Amounts reclassified to net income:						
Net realized losses on investment securities, net of $12 tax benefit					23	23
Net derivative losses hedging activities, net of $407 tax benefit					705	705
Foreign currency translation adjustments					(44)	(44)
Total comprehensive income				1,249	(367)	882
Issuance of stock equity-linked securities	7	413				413
Issuance of stock employee and direct stock purchase plans	3	206				206
Stock awards and stock options exercised (net of change in unearned compensation)	5	223				223
Cash settlement forward equity transaction		(6)				(6)
Tax benefit from stock awards and stock options exercised			31			31
Dividends				(861)		(861)
Balance at December 31, 2004	340	$ 10,888	$ 92	$ 1,442	$ (996)	$ 11,426
Comprehensive income:						
Net income				**1,033**		**1,033**
Net deferred derivative losses hedging activities, net of $1,648 tax benefit					**(2,846)**	**(2,846)**
Unrealized gains on investment securities, net of $19 tax expense					**27**	**27**
Minimum pension liability adjustment, net of $3 tax expense					**4**	**4**
Foreign currency translation adjustments					**10**	**10**

Amounts reclassified to net income:						
Net realized gains on investment securities, net of $8 tax expense					(11)	(11)
Net derivative losses hedging activities, net of $723 tax benefit					1,250	1,250
Foreign currency translation adjustments					(2)	(2)
Total comprehensive income				1,033	(1,568)	(535)
Issuance of stock employee and direct stock purchase plans		9				9
Stock awards and stock options exercised (net of change in unearned compensation)	6	363				363
Issuance of stock forward equity transaction	5	319				319
Stock repurchase and retirement	(4)	(276)				(276)
Cash settlement forward equity transaction		(17)				(17)
Tax benefit from stock awards and stock options exercised			31			31
Dividends and other adjustments			2	(925)		(923)
Balance at December 31, 2005	347	$ 11,286	$ 125	$ 1,550	$ (2,564)	$ 10,397

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

6

Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2005	2004	2003
Operating Activities			
Net income	**$ 1,033**	$ 1,249	$ 318
Adjustments to reconcile net income to net cash from operating activities:			
Impairment of telecommunications assets			566
Dominion Capital Inc. impairment losses	**35**	72	85
Impairment (recovery) of CNG International assets		(18)	84
Net realized and unrealized derivative (gains)/losses	**335**	(63)	50
Depreciation, depletion and amortization	**1,538**	1,433	1,334
Deferred income taxes and investment tax credits, net	**64**	554	452
Gain on sale of emissions allowances	**(139)**	(35)	(5)
Other adjustments to net income	**180**	9	22
Changes in:			
Accounts receivable	**(791)**	(288)	(507)
Inventories	**(220)**	(30)	(234)
Deferred fuel and purchased gas costs, net	**(57)**	89	(244)
Prepaid pension cost	**31**	(8)	(229)
Accounts payable	**686**	27	372
Accrued interest, payroll and taxes	**147**	(9)	42
Deferred revenue	**(323)**	(223)	(43)
Margin deposit assets and liabilities	**124**	(6)	(18)
Other operating assets and liabilities	**(20)**	17	305
Net cash provided by operating activities	**2,623**	2,770	2,350
Investing Activities			
Plant construction and other property additions	**(1,683)**	(1,451)	(2,138)
Additions to gas and oil properties, including acquisitions	**(1,675)**	(1,299)	(1,300)
Proceeds from sales of gas and oil properties	**595**	729	305
Acquisition of businesses	**(877)**		
Proceeds from sales of loans and securities	**754**	466	912
Purchases of securities	**(854)**	(490)	(777)
Proceeds from sale of emissions allowances	**234**	41	5
Escrow release for debt refunding			500
Purchase of Dominion Fiber Ventures senior notes			(633)
Advances to lessor for project under construction		(132)	(385)
Reimbursement from lessor for project under construction		806	
Other	**146**	115	143
Net cash used in investing activities	**(3,360)**	(1,215)	(3,368)
Financing Activities			
Issuance (repayment) of short-term debt, net	**1,045**	(879)	259
Issuance of long-term debt	**2,300**	877	3,393
Repayment of long-term debt	**(2,237)**	(1,283)	(2,922)
Issuance of common stock	**664**	839	990
Repurchase of common stock	**(276)**		
Common dividend payments	**(923)**	(861)	(825)
Other	**(51)**	(13)	(42)
Net cash provided by (used in) financing activities	**522**	(1,320)	853
Increase (decrease) in cash and cash equivalents	**(215)**	235	(165)
Cash and cash equivalents at beginning of year	**361**	126	291
Cash and cash equivalents at end of year	**$ 146**	$ 361	$ 126
Supplemental Cash Flow Information:			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 1,007**	$ 926	$ 941
Income taxes	**399**	(8)	(32)
Noncash investing and financing activities:			
Assumption of debt related to acquisitions of nonutility generating facilities	**62**	213	

Proceeds held in escrow from sale of gas and oil properties		156	
Dominion Capital Inc. exchange of notes	**258**		
Exchange of debt securities		325	500

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

Notes to Consolidated Financial Statements

Note 1. Nature of Operations

Dominion Resources, Inc. (Dominion) is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Our principal subsidiaries are Virginia Electric and Power Company (Virginia Power), Consolidated Natural Gas Company (CNG), Dominion Energy, Inc. (DEI) and Virginia Power Energy Marketing, Inc. (VPEM).

Virginia Power is a regulated public utility that generates, transmits and distributes electricity within an area of approximately 30,000 square miles in Virginia and northeastern North Carolina. Virginia Power serves approximately 2.3 million retail customer accounts, including governmental agencies and wholesale customers such as rural electric cooperatives and municipalities. On May 1, 2005, Virginia Power became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO). As a result, Virginia Power transferred functional control of its electric transmission facilities to PJM and integrated its control area into the PJM energy markets.

CNG operates in all phases of the natural gas business, explores for and produces natural gas and oil and provides a variety of energy marketing services. Its regulated gas distribution subsidiaries serve approximately 1.7 million residential, commercial and industrial gas sales and transportation customer accounts in Ohio, Pennsylvania and West Virginia and its nonregulated retail energy marketing businesses serve approximately 1.2 million residential, industrial and commercial customer accounts in the Northeast, Mid-Atlantic and Midwest. CNG also operates an interstate gas transmission pipeline and underground natural gas storage system in the Northeast, Mid-Atlantic and Midwest and a liquefied natural gas (LNG) import and storage facility in Maryland. Its producer services operations involve the aggregation of natural gas supply and related wholesale activities. CNG s exploration and production operations are located in several major gas and oil producing basins in the United States, both onshore and offshore.

DEI is involved in merchant generation, energy marketing and risk management activities and natural gas and oil exploration and production.

VPEM provides fuel and risk management services to Virginia Power and other Dominion affiliates and engages in energy trading activities. VPEM was formerly an indirect wholly-owned subsidiary of Virginia Power, however on December 31, 2005, Virginia Power transferred VPEM to Dominion through a series of dividend distributions.

We have substantially exited the core operating businesses of Dominion Capital, Inc. (DCI), whose primary business was financial services, including loan administration, commercial lending and residential mortgage lending.

We manage our daily operations through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production (E&P). In addition, we report a Corporate segment that includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management and optimization services, DCI, the net impact of our discontinued telecommunications operations that were sold in May 2004 and specific items attributable to our operating segments that are excluded from the profit measures evaluated by management in assessing segment performance or allocating resources among the segments. Our assets remain wholly owned by our legal subsidiaries.

The terms Dominion, Company, we, our and us are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Dominion Resources, Inc., one of Dominion Resources, Inc. s consolidated subsidiaries or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries.

Note 2. Significant Accounting Policies

General

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

Our Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Dominion and all majority-owned subsidiaries, and those variable interest entities (VIEs) where Dominion has been determined to be the primary beneficiary.

Certain amounts in the 2004 and 2003 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2005 presentation.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer accounts receivable at December 31, 2005 and 2004 included $396 million and $384 million, respectively, of accrued unbilled revenue based on estimated amounts of electric energy or natural gas delivered but not yet billed to our utility customers. We estimate unbilled utility revenue based on historical usage, applicable customer rates, weather factors and, for electric customers, total daily electric generation supplied after adjusting for estimated losses of energy during transmission.

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

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, federally-regulated wholesale electric sales and electric transmission services subject to cost-of-service rate regulation;
- **Nonregulated electric sales** consist primarily of sales of electricity from merchant generation facilities at market-based rates, sales of electricity to residential and commercial customers at contracted fixed prices and market-based rates and electric trading revenue;
- **Regulated gas sales** consist primarily of state-regulated retail natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas at market-based rates and contracted fixed prices, sales of gas purchased from third parties and gas trading and marketing revenue;

8

Notes to Consolidated Financial Statements, Continued

- **Other energy-related commodity sales** consist primarily of sales of coal, emissions allowances held for resale and extracted products and sales activity related to agreements used to facilitate the marketing of oil production (buy/sell arrangements) described in Note 4;
- **Gas transportation and storage** consists primarily of regulated sales of gathering, transmission, distribution and storage services. Also included are regulated gas distribution charges to retail distribution service customers opting for alternate suppliers;
- **Gas and oil production** consists primarily of sales of natural gas, oil and condensate produced by us including the recognition of revenue previously deferred in connection with the volumetric production payment (VPP) transactions described in Note 12. Gas and oil production revenue is reported net of royalties; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations; gas and oil processing and handling revenue; and business interruption insurance revenue associated with delayed gas and oil production caused by Hurricane Ivan.

See *Derivative Instruments* for a discussion of accounting changes we adopted October 1, 2003 that impacted the recognition and classification of changes in fair value, including settlements, of contracts held for energy trading and other purposes.

Electric Fuel, Purchased Energy and Purchased Gas Deferred Costs

Where permitted by regulatory authorities, the differences between actual electric fuel, purchased energy and purchased gas expenses and the levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while the recovery of fuel rate revenue in excess of current period expenses is recognized as a regulatory liability.

As for electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers are locked in until the earlier of July 1, 2007 or the termination of capped rates, with a one-time adjustment of the fuel factor, effective July 1, 2007 through December 31, 2010, with no deferred fuel accounting. As a result, approximately 12% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is subject to deferral accounting. Prior to the amendments to the Virginia Electric Utility Restructuring Act (Virginia Restructuring Act) and the Virginia fuel factor statute in 2004, approximately 93% of the cost of fuel used in electric generation and energy purchases used to serve utility customers had been subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as regulatory assets, and are subject to recovery through future rates.

Income Taxes

We file a consolidated federal income tax return for Dominion and its subsidiaries. Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*, requires an asset and liability approach to accounting for income taxes. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Where permitted by regulatory authorities, the treatment of temporary differences may differ from the requirements of SFAS No. 109. Accordingly, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities. We establish a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Deferred investment tax credits are amortized over the service lives of the properties giving rise to the credits.

Stock-based Compensation

We measure compensation expense for stock-based awards issued to our employees using the intrinsic value method prescribed by Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under this method, compensation expense for restricted stock awards equals the fair value of our common stock on the date of grant. Stock option awards generally do not result in compensation expense since their exercise price is typically equal to the market price of our common stock on the date of grant. Compensation expense, if any, for both types of awards is recognized on a straight-line basis over the stated vesting period of the award.

The following table illustrates the pro forma effect on net income and earnings per share (EPS) if we had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee compensation:

Year Ended December 31, (millions, except per share amounts)	**2005**	2004	2003
Net income as reported	**$ 1,033**	$ 1,249	$ 318
Add: actual stock-based compensation expense, net of tax(1)	**15**	10	10
Deduct: pro forma stock-based compensation expense, net of tax	**(16)**	(20)	(36)
Net income pro forma	**$ 1,032**	$ 1,239	$ 292
Basic EPS as reported	**$ 3.02**	$ 3.80	$ 1.00
Basic EPS pro forma	**3.02**	3.77	0.92
Diluted EPS as reported	**3.00**	3.78	1.00
Diluted EPS pro forma	**3.00**	3.75	0.92

(1) Actual stock-based compensation expense primarily relates to restricted stock.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until actually presented for payment. At December 31, 2005 and 2004, accounts payable includes $150 million and $129 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a remaining maturity of three months or less.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory used in local gas distribution operations is valued using the last-in-first-out (LIFO) method. Under the LIFO method, those inventories were valued at $128 million at December 31, 2005 and $59 million at December 31, 2004. Based on the

Notes to Consolidated Financial Statements, Continued

average price of gas purchased during 2005, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately $392 million. Stored gas inventory held by certain nonregulated gas operations is valued using the weighted-average cost method.

Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered from or received by a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. We value these imbalances due to or from shippers and operators at an appropriate index price, subject to the terms of our tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due from others are reported in other current assets and imbalances owed to others are reported in other current liabilities on our Consolidated Balance Sheets.

Derivative Instruments

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

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

As part of our overall strategy to market energy and manage related risks, we manage a portfolio of commodity-based derivative instruments held for trading purposes. We use established policies and procedures to manage the risks associated with the price fluctuations in these energy commodities and use various derivative instruments to reduce risk by creating offsetting market positions.

We also hold certain derivative instruments that are not held for trading purposes and are not designated as hedges for accounting purposes. However, to the extent we do not hold offsetting positions for such derivatives, we believe these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Statement of Income Presentation:

- *Derivatives Held for Trading Purposes:* All changes in fair value, including amounts realized upon settlement, are presented in revenue on a net basis as nonregulated electric sales, nonregulated gas sales and other energy-related commodity sales.
- *Financially-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* All unrealized changes in fair value and settlements are presented in other operations and maintenance expense on a net basis.
- *Physically-Settled Derivatives Not Held for Trading Purposes and Not Designated as Hedging Instruments:* Effective October 1, 2003, all unrealized changes in fair value and settlements for physical derivative sales contracts are presented in revenue, while all unrealized changes in fair value and settlements for physical derivative purchase contracts are reported in expenses. For periods prior to October 1, 2003, unrealized changes in fair value for physically settled derivative contracts are presented in other operations and maintenance expense on a net basis.

We recognize revenue or expense from all non-derivative energy-related contracts on a gross basis at the time of contract performance, settlement or termination.

Derivative Instruments Designated as Hedging Instruments

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

Cash Flow Hedges A significant portion of our hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas and oil. We also use foreign currency forward contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are reported in accumulated other comprehensive income (loss) (AOCI), to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. For cash flow hedge transactions, we discontinue hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. We reclassify any derivative gains or losses reported in AOCI to earnings when the forecasted item is included in earnings, if it should occur, or earlier, if it becomes probable that the forecasted transaction will not occur.

Fair Value Hedges We also use fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and natural gas inventory. In addition, we have designated interest rate swaps as fair value hedges to manage our interest rate exposure on certain fixed rate long-term debt. For fair value hedge transactions, changes in the fair value of the

Notes to Consolidated Financial Statements, Continued

derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value.

Statement of Income Presentation Gains and losses on derivatives designated as hedges, when recognized, are included in operating revenue, operating expenses or interest and related charges in our Consolidated Statements of Income. Specific line item classification is determined based on the nature of the risk underlying individual hedge strategies. The portion of gains or losses on hedging instruments determined to be ineffective and the portion of gains or losses on hedging instruments excluded from the measurement of the hedging relationship s effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, are included in other operations and maintenance expense.

Valuation Methods

Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, we must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis.

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

Investment Securities

We account for and classify investments in marketable equity and debt securities in two categories. Debt and equity securities purchased and held with the intent of selling them in the near-term are classified as trading securities. Trading securities are reported at fair value with net realized and unrealized gains and losses included in earnings. All other debt and equity securities, including all investments held by our nuclear decommissioning trusts, are classified as available-for-sale securities.

Available-for-sale securities are reported at fair value with realized gains and losses and any other-than-temporary declines in fair value included in earnings and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale to determine whether a decline in fair value should be considered other-than-temporary. Retained interests from securitizations of financial assets are evaluated in accordance with Emerging Issues Task Force (EITF) Issue No. 99-20, *Recognition of Interest Income and Impairments of Purchased and Retained Beneficial Interests in Securitized Financial Assets*. For other securities, we use several criteria to evaluate other-than-temporary declines, including length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its average cost and the expected fair value of the security. If the market value of the security has been less than cost for more than eight months and the decline in value is greater than 50% of its average cost, the security is written down to fair value at the end of the reporting period. If only one of the above criteria is met, a further analysis is performed to evaluate the expected recovery value based on third-party price targets. If the third-party price targets are below the security s average cost and one of the other criteria has been met, the decline is considered other-than-temporary and the security is written down to fair value at the end of the reporting period.

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as incurred. In 2005, 2004 and 2003, we capitalized interest costs of $99 million, $70 million and $96 million, respectively.

For electric distribution and transmission property and natural gas property subject to cost-of-service rate regulation, the depreciable cost of such property, less salvage value, is charged to accumulated depreciation at retirement. Cost of removal collections from utility customers and expenditures not representing asset retirement obligations (AROs) are recorded as regulatory liabilities or regulatory assets.

For generation-related and nonutility property, cost of removal not associated with AROs is charged to expense as incurred. We record gains and losses upon retirement of generation-related and nonutility property based upon the difference between proceeds received, if any, and the property s undepreciated basis at the retirement date.

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

	2005	2004	2003
(percent)			
Generation	**2.04**	1.97	1.83
Transmission	**2.25**	2.21	2.22
Distribution	**3.19**	3.19	3.18
Storage	**3.15**	3.04	2.81
Gas gathering and processing	**2.21**	2.31	2.39
General and other	**5.80**	6.03	5.73

Our nonutility property, plant and equipment, excluding exploration and production properties, is depreciated using the straight-line method over the following estimated useful lives:

Asset	**Estimated Useful Lives**
Merchant generation nuclear	29 44 years
Merchant generation other	6 65 years
General and other	3 25 years

11

Notes to Consolidated Financial Statements, Continued

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis.

We follow the full cost method of accounting for gas and oil exploration and production activities prescribed by the Securities and Exchange Commission (SEC). Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. These capitalized costs are subject to a quarterly ceiling test. Under the ceiling test, amounts capitalized are limited to the present value of estimated future net revenues to be derived from the anticipated production of proved gas and oil reserves, assuming period-end pricing adjusted for cash flow hedges in place. If net capitalized costs exceed the ceiling test at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period. The ceiling test is performed separately for each cost center, with cost centers established on a country-by-country basis. Approximately 10% of our anticipated production is hedged by qualifying cash flow hedges, for which hedge-adjusted prices were used to calculate estimated future net revenue. Whether period-end market prices or hedge-adjusted prices were used for the portion of production that is hedged, there was no ceiling test impairment as of December 31, 2005. Future cash flows associated with settling AROs that have been accrued on our Consolidated Balance Sheets pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations*, are excluded from our calculations under the full cost ceiling test.

Depreciation of gas and oil producing properties is computed using the units-of-production method. Under the full cost method, the depreciable base of costs subject to amortization also includes estimated future costs to be incurred in developing proved gas and oil reserves, as well as capitalized asset retirement costs, net of projected salvage values. The costs of investments in unproved properties are initially excluded from the depreciable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depreciable base, determined on a property by property basis, over terms of underlying leases. Once a property has been evaluated, any remaining capitalized costs are then transferred to the depreciable base. In addition, gains or losses on the sale or other disposition of gas and oil properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil attributable to a country.

Emissions Allowances

Emissions allowances are issued by the Environmental Protection Agency (EPA) and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (NO_x). Allowances may be transacted with third parties or consumed as these emissions are generated. Allowances allocated to or acquired by our generation and LNG operations are held primarily for consumption. Allowances acquired by our trading and risk management operations are held primarily for the purpose of resale to third parties.

Allowances Held for Consumption

Allowances held for consumption are classified as intangible assets which are included in other assets on our Consolidated Balance Sheets. Carrying amounts are based upon our cost to acquire the allowances, or in the case of a business combination, the fair values assigned to them in our allocation of the purchase price of the acquired business. Allowances issued directly to us by the EPA are carried at zero cost.

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

Allowances Held for Resale

Allowances held for resale are classified as materials and supplies inventory on our Consolidated Balance Sheets. Carrying amounts are based upon our cost to acquire the allowances.

These allowances are not consumed and therefore are not subject to amortization. We report purchases and sales of these allowances as operating activities on our Consolidated Statements of Cash Flows. Sales of these allowances are reported in operating revenue and purchases of allowances are reported in other energy-related commodity purchases expense on our Consolidated Statements of Income.

Goodwill and Intangible Assets

We evaluate goodwill for impairment annually, as of April 1st, and whenever an event occurs or circumstances change in the interim that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Intangible assets with finite lives are amortized over their estimated useful lives or as consumed.

Impairment of Long-Lived and Intangible Assets

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

Regulatory Assets and Liabilities

For utility operations subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates and when revenue is collected from customers for expenditures that are not yet incurred. Regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the recovery period authorized by the regulator.

Asset Retirement Obligations

We recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of the retirement activities to be performed. These amounts are capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, we estimate fair value using discounted cash flow analyses. We report the accretion of the AROs due to the passage of time in other operations and maintenance expense.

Notes to Consolidated Financial Statements, Continued

Amortization of Debt Issuance Costs

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

Note 3. Newly Adopted Accounting Standards

2005

SFAS No. 153

On July 1, 2005, we adopted SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29*, which requires that all commercially substantive exchange transactions, for which the fair value of the assets exchanged are reliably determinable, be recorded at fair value, whether or not they are exchanges of similar productive assets. This amends the exception from fair value measurements in APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, for nonmonetary exchanges of similar productive assets and replaces it with an exception for only those exchanges that do not have commercial substance. There was no impact on our results of operations or financial condition related to our adoption of SFAS No. 153 and we do not expect the ongoing application of SFAS No. 153 to have a material impact on our results of operations or financial condition.

FIN 47

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on December 31, 2005. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when the obligation is incurred generally upon acquisition, construction, or development and/or through the normal operation of the asset, if the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Uncertainty about the timing and/or method of settlement is required to be factored into the measurement of the liability when sufficient information exists. Our adoption of FIN 47 resulted in the recognition of an after-tax charge of $6 million, representing the cumulative effect of the change in accounting principle.

Presented below are our pro forma net income and earnings per share as if we had applied the provisions of FIN 47 as of January 1, 2003.

Year Ended December 31, (millions, except per share amounts)	**2005**	2004	2003
Net income as reported	**$ 1,033**	$ 1,249	$ 318
Net income pro forma	**1,038**	1,248	317
Basic EPS as reported	**3.02**	3.80	1.00
Basic EPS pro forma	**3.03**	3.79	1.00
Diluted EPS as reported	**3.00**	3.78	1.00
Diluted EPS pro forma	**3.02**	3.78	1.00

If we had applied the provisions of FIN 47 as of January 1, 2003, our asset retirement obligations would have increased by $124 million, $131 million and $140 million, as of January 1, 2003, December 31, 2003 and December 31, 2004, respectively.

2004

FIN 46R

We adopted FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), for our interests in VIEs that are not considered special purpose entities on March 31, 2004. FIN 46R addresses the identification and consolidation of VIEs, which are entities that are not controllable through voting interests or in which the VIEs equity investors do not bear the residual economic risks and rewards in proportion to voting rights. There was no impact on our results of operations or financial position related to this adoption. See Note 16.

EITF 04-8

On December 31, 2004, we adopted EITF Issue No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*, which requires the shares issuable under contingently convertible instruments to be included in the diluted EPS calculation regardless of whether the market price trigger (or other contingent feature) has been met. Prior to adoption, we exchanged $219 million of outstanding contingent convertible senior notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The new notes outstanding on December 31, 2004 were included in the diluted EPS calculation retroactive to the date of issuance using the method described in EITF 04-8. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This did not result in an increase to the average shares outstanding used in the 2004 calculation of our diluted EPS since the conversion price included in the notes was greater than the average market price. In 2005, we exchanged an additional $1 million of outstanding contingent convertible senior notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash.

2003

SFAS No. 143

Effective January 1, 2003, we adopted SFAS No. 143, which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The effect of adopting SFAS No. 143 for 2003, as compared to an estimate of net income reflecting the continuation of former accounting policies, was to increase net income by $201 million. The increase is comprised of a $180 million after-tax benefit, representing the cumulative effect of a change in accounting principle and an increase in income before the cumulative effect of a change in accounting principle of $21 million.

EITF 02-3

On January 1, 2003, we adopted EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, that rescinded EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk*

Notes to Consolidated Financial Statements, Continued

Management Activities. Adopting EITF 02-3 resulted in the discontinuance of fair value accounting for non-derivative contracts held for trading purposes. Those contracts are recognized as revenue or expense at the time of contract performance, settlement or termination. The EITF 98-10 rescission was effective for non-derivative energy trading contracts initiated after October 25, 2002. For all non-derivative energy trading contracts initiated prior to October 25, 2002, we recognized a charge of $67 million ($43 million after-tax) as the cumulative effect of this change in accounting principle on January 1, 2003.

EITF 03-11

We adopted EITF Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3*, on October 1, 2003. EITF 03-11 addresses classification of income statement related amounts for derivative contracts. Income statement amounts related to periods prior to October 1, 2003 are presented as originally reported. See Note 2.

Statement 133 Implementation Issue No. C20

In connection with a request to reconsider an interpretation of SFAS No. 133, the FASB issued Statement 133 Implementation Issue No. C20, *Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature*. Issue C20 establishes criteria for determining whether a contract s pricing terms that contain broad market indices (e.g., the consumer price index) could qualify as a normal purchase or sale and, therefore, not be subject to fair value accounting. We had several contracts that qualified as normal purchase and sales contracts under the Issue C20 guidance. However, the adoption of Issue C20 required those contracts to be initially recorded at fair value as of October 1, 2003, resulting in the recognition of an after-tax charge of $75 million, representing the cumulative effect of the change in accounting principle. As normal purchase and sales contracts, no further changes in fair value were recognized.

FIN 46R

On December 31, 2003, we adopted FIN 46R for our interests in special purpose entities, resulting in the consolidation of several special purpose lessor entities through which we had constructed, financed and leased several new power generation projects, as well as our corporate headquarters and aircraft. As a result, our Consolidated Balance Sheet as of December 31, 2003 reflected an additional $644 million in net property, plant and equipment and deferred charges and $688 million of related debt. This resulted in additional depreciation expense of approximately $20 million in both 2005 and 2004. The cumulative effect in 2003 of adopting FIN 46R for our interests in special purpose entities was an after-tax charge of $27 million, representing depreciation expense and amortization associated with the consolidated assets.

From 1997 through 2002, we established five capital trusts that sold trust preferred securities to third-party investors. We received the proceeds from the sale of the trust preferred securities in exchange for various junior subordinated notes issued to be held by the trusts. Upon adoption of FIN 46R, we began reporting as long-term debt our junior subordinated notes held by the trusts rather than the trust preferred securities. As a result, in 2005 and 2004, we reported interest expense on the junior subordinated notes rather than preferred distribution expense on the trust preferred securities.

Note 4. Recently Issued Accounting Standards

SFAS No. 123R

SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), requires that compensation cost relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans. In addition, SFAS No. 123R clarifies the timing of expense recognition for share-based awards with terms that accelerate vesting upon retirement.

Our restricted stock awards contain terms that accelerate vesting upon retirement. Under current practice, compensation cost for these awards is recognized over the stated vesting term unless vesting is actually accelerated by retirement. Upon adoption of SFAS No. 123R, we will continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but will be required to recognize compensation cost over the shorter of the stated vesting term or period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards. At December 31, 2005, unrecognized compensation cost for restricted stock awards held by retirement eligible employees totaled $9 million.

SFAS No. 123R also requires the benefits of tax deductions in excess of recognized share-based compensation expense to be classified as a financing cash flow, rather than as an operating cash flow. This requirement will reduce net operating cash flow and increase net financing cash flow in periods after adoption.

We adopted SFAS No. 123R and related guidance on January 1, 2006, using the modified prospective transition method. Under this transition method, compensation cost will be recognized (a) based on the requirements of SFAS No. 123R for all share-based awards granted subsequent to January 1, 2006 and (b) based on the original provisions of SFAS No. 123 for all awards granted prior to January 1, 2006, but not vested as of this date. Results for prior periods will not be restated. The ongoing application of SFAS No. 123R is not expected to have a material impact on our results of operations or financial condition.

SFAS No. 154

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods financial statements of a voluntary change in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. We will apply the provisions of SFAS No. 154 to voluntary accounting changes on or after January 1, 2006.

14

Notes to Consolidated Financial Statements, Continued

EITF 04-5

In June 2005, the FASB ratified the consensus reached by the EITF on Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*. EITF 04-5 provides guidance in assessing when a general partner should consolidate its investment in a limited partnership or similar entity. The provisions of EITF 04-5 were required to be applied beginning June 30, 2005 by general partners of all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements are modified and is effective for general partners in all other limited partnerships beginning January 1, 2006. There was no impact on our results of operations or financial condition related to our adoption of EITF 04-5.

EITF 04-13

We enter into buy/sell and related agreements primarily as a means to reposition our offshore Gulf of Mexico crude oil production to more liquid marketing locations onshore. We typically enter into either a single or a series of buy/sell transactions in which we sell our crude oil production at the offshore field delivery point and buy similar quantities at Cushing, Oklahoma for sale to third parties. We are able to enhance profitability by selling to a wide array of refiners and/or trading companies at Cushing, one of the largest crude oil markets in the world, versus restricting sales to a limited number of refinery purchasers in the Gulf of Mexico.

Under the primary guidance of EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent,* we present the sales and purchases related to our crude oil buy/sell arrangements on a gross basis in our Consolidated Statements of Income. These transactions require physical delivery of the crude oil and the risks and rewards of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling and counterparty nonperformance risk. Sale activity included in operating revenue was $377 million, $290 million and $181 million in 2005, 2004 and 2003, respectively. Purchase activity included in other energy-related commodity purchases expense was $362 million, $271 million and $163 million in 2005, 2004 and 2003, respectively.

In September 2005, the FASB ratified the EITF s consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, that will require buy/sell and related agreements to be presented on a net basis in the Consolidated Statements of Income if they are entered into in contemplation of one another. This new guidance is required to be applied to all new arrangements entered into, and modifications or renewals of existing arrangements, beginning April 1, 2006. We are currently assessing the impact that this new guidance may have on our income statement presentation of these transactions; however, there will be no impact on our results of operations or cash flows.

Note 5. Acquisitions

USGen Power Plants

In January 2005, we completed the acquisition of three fossil fired generation facilities from USGen New England, Inc. for $642 million in cash. The plants, collectively referred to as Dominion New England, include the 1,560-megawatt Brayton Point Station in Somerset, Massachusetts; the 754-megawatt Salem Harbor Station in Salem, Massachusetts; and the 432-megawatt Manchester Street Station in Providence, Rhode Island. The operations of Dominion New England are included in the Dominion Generation operating segment.

Kewaunee Power Station

In July 2005, we completed the acquisition of the 556-megawatt Kewaunee nuclear power station (Kewaunee), located in northeastern Wisconsin, from Wisconsin Public Service Corporation, a subsidiary of WPS Resources Corporation (WPS), and Wisconsin Power and Light Company (WP&L), a subsidiary of Alliant Energy Corporation for approximately $192 million in cash. We sell 100% of the facility s output to WPS (59%) and WP&L (41%) under two power purchase agreements that will expire in 2013. The operations of Kewaunee are included in the Dominion Generation operating segment.

The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the date of the acquisition. We may make adjustments to the initial purchase price allocation to reflect the receipt of additional information.

Note 6. Operating Revenue

Our operating revenue consists of the following:

Year Ended December 31, (millions)	**2005**	2004	2003
Electric sales:			
Regulated	**$ 5,543**	$ 5,180	$ 4,876
Nonregulated	**3,113**	1,249	1,130
Gas sales:			
Regulated	**1,763**	1,422	1,258
Nonregulated	**2,945**	2,082	1,718
Other energy-related commodity sales	**1,672**	1,272	588
Gas transportation and storage	**900**	802	740
Gas and oil production	**1,704**	1,636	1,503
Other	**401**	348	282
Total operating revenue	**$ 18,041**	$ 13,991	$ 12,095

15

Notes to Consolidated Financial Statements, Continued

Note 7. Income Taxes

Income from continuing operations before provision for income taxes (pre-tax income), classified by source of income, and the details of income tax expense for continuing operations were as follows:

Year Ended December 31, (millions)	**2005**	2004	2003
Income from continuing operations before income tax expense:			
U.S.	**$ 1,587**	$ 1,938	$ 1,506
Non-U.S.	**29**	26	40
Total	**1,616**	1,964	1,546
Income tax expense:			
Current			
Federal	**410**	62	121
State	**104**	82	22
Non-U.S.		(3)	1
Total current	**514**	141	144
Deferred			
Federal	**88**	580	433
State	**(18)**	(16)	32
Non-U.S.	**15**	12	6
Total deferred	**85**	576	471
Amortization of deferred investment tax credits net	**(17)**	(17)	(18)
Total income tax expense	**$ 582**	$ 700	$ 597

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

Year Ended December 31,	**2005**	2004	2003
U.S. statutory rate	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:			
Valuation allowance	**1.2**	(0.3)	4.0
State income taxes, net of federal benefit	**3.4**	2.2	2.2
Utility plant differences		0.1	(0.4)
Preferred dividends	**0.3**	0.3	0.4
Amortization of investment tax credits	**(0.8)**	(0.7)	(0.9)
Other benefits and taxes / foreign operations	**(0.4)**		(0.5)
Employee pension and other benefits	**(1.2)**	(0.5)	(0.7)
Employee stock ownership plan and restricted stock dividends	**(0.8)**	(0.5)	(0.7)
Other, net	**(0.7)**		0.2
Effective tax rate	**36.0%**	35.6%	38.6%

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

At December 31, (millions)	**2005**	2004
Deferred income tax assets:		
Other comprehensive income	**$ 1,505**	$ 594
Other	**644**	520
Loss and credit carryforwards	**893**	798
Valuation allowance	**(339)**	(328)
Total deferred income tax assets	**2,703**	1,584

Deferred income tax liabilities:		
Depreciation method and plant basis differences	**2,798**	2,959
Partnership basis differences	**181**	167
Pension benefits	**677**	754
Gas and oil exploration and production related differences	**1,956**	1,607
Deferred state income taxes	**465**	471
Other	**624**	456
Total deferred income tax liabilities	**6,701**	6,414
Total net deferred income tax liabilities	**$ 3,998**	$ 4,830

At December 31, 2005, we had the following loss and credit carryforwards:

- Federal loss carryforwards of $1.3 billion that expire if unutilized during the period 2007 through 2024. A valuation allowance on $783 million in carryforwards has been established due to the uncertainty of realizing these future deductions;
- State loss carryforwards of $1.9 billion that expire if unutilized during the period 2006 through 2025. A valuation allowance on $844 million has been established for these carryforwards; and
- Federal and state minimum tax credits of $316 million that do not expire and other federal and state income tax credits of $74 million that will expire if unutilized during the period 2006 through 2011.

Other

We have not provided for U.S. deferred income taxes or foreign withholding taxes on remaining undistributed earnings of $146 million from our non-U.S. subsidiaries since we do not intend to repatriate those earnings.

We are routinely audited by federal and state tax authorities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret them differently. We establish liabilities for tax-related contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*, and review them in light of changing facts and circumstances. Ultimate resolution of income tax matters may result in favorable or unfavorable adjustments that could be material. Our estimated income tax payments for 2005 were reduced by deducting a calendar year 2003 net operating loss, a substantial portion of which resulted from a write-off related to our discontinued telecommunications business, Dominion Fiber Ventures, LLC (DFV). The DFV deduction reduced our 2005 income tax payments by approximately $116 million. We have not yet recognized in net income any tax benefits related to the deduction. If our tax deduction is challenged and ultimately not sustained, we will have to pay $116 million

Notes to Consolidated Financial Statements, Continued

plus accrued interest. At December 31, 2005 and December 31, 2004, our Consolidated Balance Sheets reflect $144 million and $52 million, respectively, of income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Jobs Act)

The Jobs Act has several provisions for energy companies, including a deduction related to taxable income derived from qualified production activities. Our electric generation and oil and gas extraction activities qualify as production activities under the Jobs Act. The Jobs Act limits the deduction to the lesser of taxable income derived from qualified production activities or our consolidated federal taxable income. Our qualified production activities deduction for 2005 is limited to a minimal amount.

Also, under the Jobs Act, United States companies could have repatriated foreign earnings at a substantially reduced tax rate until December 2005. We did not repatriate any funds under this provision.

Note 8. Hedge Accounting Activities

We are exposed to the impact of market fluctuations in the price of natural gas, electricity and other energy-related products marketed and purchased as well as currency exchange and interest rate risks of our business operations. We use derivative instruments to manage our exposure to these risks and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes as allowed by SFAS No. 133. Selected information about our hedge accounting activities follows:

Year Ended December 31, (millions)	**2005**	2004	2003
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:			
Fair value hedges	**$ 18**	$ (2)	$ (3)
Cash flow hedges (1)	**(79)**	10	7
Net ineffectiveness	**$ (61)**	$ 8	$ 4
Portion of gains (losses) on hedging instruments excluded from measurement of effectiveness and included in net income:			
Fair value hedges (2)	**$ 4**	$ 3	$ 1
Cash flow hedges (3)	**(2)**	101	7
Total	**$ 2**	$ 104	$ 8

(1) Represents an increase in hedge ineffectiveness expense primarily due to an increase in the fair value differential between the delivery location and commodity specifications of derivative contracts held by our exploration and production operations and the delivery location and commodity specifications of our forecasted gas and oil sales.
(2) Amounts relate to changes in the difference between spot prices and forward prices for 2005 and 2004 and to changes in options time value for 2003.
(3) Amounts relate to changes in options time value.

The following table presents selected information related to cash flow hedges included in AOCI in the Consolidated Balance Sheet at December 31, 2005:

	AOCI After Tax	**Portion Expected to be Reclassified to Earnings during the Next**	**Maximum Term**

(millions)		12 Months After Tax	
Commodities:			
Gas	$ (1,495)	$ (821)	60 months
Oil	(548)	(313)	36 months
Electricity	(743)	(413)	36 months
Interest rate	(15)	8	246 months
Foreign currency	24	11	23 months
Total	$ (2,777)	$ (1,528)	

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

Due to interruptions in the Gulf of Mexico oil production caused by Hurricane Ivan, we discontinued hedge accounting for certain cash flow hedges in September 2004 since it became probable that the forecasted sales of oil would not occur. In connection with the discontinuance of hedge accounting for these contracts we reclassified $71 million of pre-tax losses from AOCI to earnings in September 2004.

As a result of a delay in reaching anticipated production levels in the Gulf of Mexico, we discontinued hedge accounting for certain cash flow hedges in March 2005 since it became probable that the forecasted sales of oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we reclassified $30 million ($19 million after-tax) of losses from AOCI to earnings in March 2005. Through December 31, 2005, we have recognized additional losses of $29 million ($19 million after-tax) due to subsequent changes in the fair value of these contracts.

Additionally, due to interruptions in Gulf of Mexico and southern Louisiana gas and oil production caused by Hurricanes Katrina and Rita, we discontinued hedge accounting for certain cash flow hedges in August and September 2005 since it became probable that the forecasted sales of gas and oil would not occur. In connection with the discontinuance of hedge accounting for these contracts, we reclassified $423 million ($272 million after-tax) of losses from AOCI to earnings in the third quarter of 2005. Through December 31, 2005, we have recognized additional losses of $12 million ($8 million after-tax) due to subsequent changes in the fair value of these contracts. Losses related to the discontinuance of hedge accounting are reported in other operations and maintenance expense in our Consolidated Statements of Income.

Notes to Consolidated Financial Statements, Continued

Note 9. Discontinued Operations Telecommunications Operations

DFV was a joint venture originally formed by Dominion and a third-party investor trust (Investor Trust) to fund the development of its principal subsidiary, Dominion Telecom, Inc. (Dominion Telecom). Dominion Telecom was a facilities-based interchange and emerging local carrier, providing broadband solutions to wholesale customers throughout the eastern United States. Due to a weak pricing environment resulting from excess capacity in the telecommunications industry and the markets for these services not growing at rates originally contemplated, we approved a strategy to sell our interest in the telecommunications business and began reporting Dominion Telecom as a discontinued operation in the fourth quarter of 2003.

In connection with its formation, DFV issued $665 million of 7.05% senior secured notes due March 2005 that were secured in part by Dominion convertible preferred stock held in trust. We were the beneficial owner of the trust and thus did not present the convertible preferred stock in our Consolidated Balance Sheets. During 2004, as a result of the retirement of DFV s senior notes, the trust was dissolved and the convertible preferred stock was retired.

2005 and 2004 Sale of Dominion Telecom

In May 2004, we completed the sale of our discontinued telecommunication operations to Elantic Telecom, Inc. (ETI), realizing a loss of $11 million ($7 million after-tax, $0.02 per share) related to the sale. The results of telecommunications operations, including revenue of $8 million and a loss before income taxes of $19 million, are presented as discontinued operations, on a net basis, in our Consolidated Statement of Income for 2004. In July 2004, ETI filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code, which was subsequently approved by the U.S. Bankruptcy Court. ETI s plan of reorganization became effective in May 2005, and ETI emerged from bankruptcy. In September 2005, ETI, its parent and various Dominion entities reached a comprehensive settlement of various issues that was subsequently approved by the U.S. Bankruptcy Court. We recognized a benefit of $8 million ($5 million after-tax) in 2005, from the revaluation of an outstanding guarantee associated with the sale transaction. In addition to this $8 million outstanding guarantee, we have several potential indemnification obligations related to our discontinued telecommunications operations.

2003 Asset Impairments

The change in strategy in 2003 included a review of Dominion Telecom s network assets and related inventories for impairment. As a result, we recognized a $566 million impairment of network assets and related inventories, reflecting the excess of the assets carrying amount over their estimated fair values. This amount included the allocation of $16 million to the Investor Trust, representing the minority interest s share of these charges. We determined the estimated fair values with the assistance of an independent appraiser and subsequently updated the fair values based on preliminary bids received in connection with the sale of Dominion Telecom.

Since realization of tax benefits related to the impairment charges will be dependent upon our expected future tax profile, we established a valuation allowance that completely offsets the deferred tax benefits. In addition, we increased the valuation allowance on deferred tax assets previously recognized, resulting in a $48 million increase in deferred income tax expense.

2003 Additional Investments in DFV

The DFV senior notes contained certain stock price and credit downgrade triggers that could have resulted in the issuance of the convertible preferred stock held in trust. In the first quarter of 2003, we purchased $633 million of DFV senior notes to reduce the likelihood that the remarketing of the Dominion convertible preferred stock held in trust would ever occur and, in connection with the purchase, obtained consent to remove the triggers from the indenture. We paid a total of $664 million for the notes acquired and recognized a pre-tax charge of $57 million, reported in other expenses on our Consolidated Statement of Income. The charge consisted of the premium paid to acquire the notes, the consent fee paid to the note holders and the recognition of previously unamortized debt costs. After the transaction, we owned a total of $644 million of DFV senior notes with the remaining $21 million of outstanding notes held by third parties.

We began consolidating the results of DFV in our Consolidated Financial Statements in February 2003, as a result of acquiring substantially all of DFV s outstanding senior notes. Prior to this acquisition, we accounted for DFV as an equity-method investment, due to the Investor Trust s equity investment and veto rights.

In the fourth quarter of 2003, we purchased the Investor Trust s interest in DFV for $62 million, including $2 million for accrued dividends. This transaction was accounted for as a purchase of a minority interest and $60 million was recognized as goodwill and impaired. The purchase enabled us to proceed with our strategy to sell Dominion Telecom and, accordingly, classify the business as discontinued operations as of December 31, 2003. The results of telecommunications operations, including revenue of $18 million and a loss before income taxes of $627 million, were presented as discontinued operations, on a net basis, on the Consolidated Statement of Income for 2003.

2003 Other

Also early in 2003, we recognized a $27 million charge for the reallocation of DFV s equity losses between the Investor Trust and Dominion. Based on updated projections of DFV s expected net losses, Dominion and the Investor Trust revised the allocation of equity losses, using cash allocations and liquidation provisions of the underlying limited liability company agreement rather than voting interests.

18

Notes to Consolidated Financial Statements, Continued

Note 10. Earnings Per Share

The following table presents the calculation of our basic and diluted EPS:

Year Ended December 31, (millions, except per share amounts)	**2005**	2004	2003
Income from continuing operations before cumulative effect of changes in accounting principles	**$ 1,034**	$ 1,264	$ 949
Income (loss) from discontinued operations	**5**	(15)	(642)
Cumulative effect of changes in accounting principles	**(6)**		11
Net income	**$ 1,033**	$ 1,249	$ 318
Basic EPS			
Average shares of common stock outstanding basic	**342.3**	329.1	317.5
Income from continuing operations before cumulative effect of changes in accounting principles	**$ 3.02**	$ 3.84	$ 2.99
Income (loss) from discontinued operations	**0.02**	(0.04)	(2.02)
Cumulative effect of changes in accounting principles	**(0.02)**		0.03
Net income	**$ 3.02**	$ 3.80	$ 1.00
Diluted EPS			
Average shares of common stock outstanding	**342.3**	329.1	317.5
Net effect of potentially dilutive securities[1]	**2.1**	1.4	1.3
Average shares of common stock outstanding diluted	**344.4**	330.5	318.8
Income from continuing operations before cumulative effect of changes in accounting principles	**$ 3.00**	$ 3.82	$ 2.98
Income (loss) from discontinued operations	**0.02**	(0.04)	(2.01)
Cumulative effect of changes in accounting principles	**(0.02)**		0.03
Net income	**$ 3.00**	$ 3.78	$ 1.00

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities, contingently convertible senior notes and shares that were issuable under a forward equity sale agreement.

Potentially dilutive securities with the right to purchase approximately 3 million, 5 million and 10 million common shares for the years ended 2005, 2004 and 2003, respectively, were not included in the respective period s calculation of diluted EPS because the exercise or purchase prices included in those instruments were greater than the average market price of the common shares.

Note 11. Investment Securities

We hold marketable debt and equity securities in nuclear decommissioning trust funds, retained interests from prior securitizations of financial assets and subordinated notes related to certain collateralized debt obligations, all of which are classified as available-for-sale. In addition, we hold marketable debt and equity securities, which are classified as trading, in rabbi trusts associated with certain deferred compensation plans.

Available-for-sale securities as of December 31, 2005 and 2004 are summarized below:

(millions)	**Fair Value**	**Total Unrealized Gains Included in AOCI**	**Total Unrealized Losses Included in AOCI**
2005			
Equity securities	**$ 1,598**	**$ 296**	**$ 25**

Debt securities	**1,157**	**11**	**8**
Total	**$ 2,755**	**$ 307**	**$ 33**
2004			
Equity securities	$ 1,229	$ 240	$ 12
Debt securities	1,044	20	1
Total	$ 2,273	$ 260	$ 13

The following table presents the fair value and gross unrealized losses of our available-for-sale securities, aggregated by investment category and the length of time the securities have been in a continuous loss position, at December 31, 2005:

	Equity Securities		Debt Securities	
(millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Less than 12 months	$ 168	$ 17	$ 430	$ 7
12 months or more	38	8	40	1
Total	$ 206	$ 25	$ 470	$ 8

Debt securities backed by mortgages and loans do not have stated contractual maturities as borrowers have the right to call or repay obligations with or without call or prepayment penalties. At December 31, 2005, these debt securities totaled $285 million. The fair value of all other debt securities at December 31, 2005 by contractual maturity are as follows:

(millions)	**Amount**
Due in one year or less	$ 40
Due after one year through five years	260
Due after five years through ten years	290
Due after ten years	282
Total	$ 872

Presented below is selected information regarding the sales of investment securities. In determining realized gains and losses, the cost of these securities was determined on a specific identification basis.

Year Ended December 31, (millions)	**2005**	2004	2003
Available-for-sale securities:			
Proceeds from sales	**$ 754**	$ 463	$ 832
Realized gains	**46**	57	62
Realized losses	**49**	90	102
Trading securities:			
Net unrealized gain	**6**	4	12

19

Notes to Consolidated Financial Statements, Continued

Note 12. Property, Plant and Equipment

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

At December 31, (millions)	2005	2004
Utility		
Generation	$ 10,243	$ 10,135
Transmission	3,570	3,464
Distribution	8,408	8,024
Storage	947	1,023
Nuclear fuel	870	795
Gas gathering and processing	433	418
General and other	736	774
Plant under construction	954	674
Total utility	26,161	25,307
Nonutility		
Exploration and production properties being amortized:		
Proved	9,929	8,246
Unproved	753	653
Unproved exploration and production properties not being amortized	1,022	970
Merchant generation nuclear	1,109	997
Merchant generation other	1,612	1,268
Nuclear fuel	361	271
Other including plant under construction	1,116	951
Total nonutility	15,902	13,356
Total property, plant and equipment	$ 42,063	$ 38,663

Costs of unproved properties capitalized under the full cost method of accounting that were excluded from amortization at December 31, 2005 and the years in which such excluded costs were incurred, are as follows:

(millions)	Total	2005	2004	2003	Years Prior
Property acquisition costs	$ 637	$ 89	$ 33	$ 22	$ 493
Exploration costs	221	93	67	20	41
Capitalized interest	164	44	39	45	36
Total	$ 1,022	$ 226	$ 139	$ 87	$ 570

There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 2005. As gas and oil reserves are proved through drilling or as properties are deemed to be impaired, excluded costs and any related reserves are transferred on an ongoing, well-by-well basis into the amortization calculation.

Amortization rates for capitalized costs under the full cost method of accounting for our United States and Canadian cost centers were as follows:

Year Ended December 31, (Per Mcf Equivalent)	2005	2004	2003
United States cost center	$ 1.41	$ 1.28	$ 1.20
Canadian cost center	1.82	1.18	1.00

Volumetric Production Payment Transactions

In 2005, we received $424 million in cash for the sale of a fixed-term overriding royalty interest in certain of our natural gas reserves for the period March 2005 through February 2009. The sale reduced our proved natural gas reserves by approximately 76 billion cubic feet (bcf). While we are obligated under the agreement to deliver to the purchaser its portion of future natural gas production from the properties, we retain control of the properties and rights to future development drilling. If production from the properties subject to the sale is inadequate to deliver the approximately 76 bcf of natural gas scheduled for delivery to the purchaser, we have no obligation to make up the shortfall. Cash proceeds received from this VPP transaction were recorded as deferred revenue. We will recognize revenue from the transaction as natural gas is produced and delivered to the purchaser. We previously entered into VPP transactions in 2004 and 2003 for approximately 83 bcf for the period May 2004 through April 2008 and 66 bcf for the period August 2003 through July 2007, respectively.

Sale of British Columbia Assets

In December 2004, we sold the majority of our natural gas and oil assets in British Columbia, Canada, for $476 million, which was credited to our Canadian full cost pool. We received cash proceeds of $320 million in December 2004 and $156 million in January 2005. The properties sold produced about 30 bcf equivalent net of natural gas annually. We recorded expenses of $10 million in other operations and maintenance expense related to the sale.

Jointly-Owned Utility Plants

Our proportionate share of jointly-owned utility plants at December 31, 2005 is as follows:

(millions, except percentages)	**Bath County Pumped Storage Station**	**North Anna Power Station**	**Clover Power Station**
Ownership interest	60.0%	88.4%	50.0%
Plant in service	$ 1,007	$ 2,075	$ 553
Accumulated depreciation	(395)	(930)	(122)
Nuclear fuel		393	
Accumulated amortization of nuclear fuel		(312)	
Plant under construction	34	59	1

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

Note 13. Goodwill and Intangible Assets

Goodwill

There was no impairment of or material change to the carrying amount or segment allocation of goodwill in 2005 or 2004.

In 2003, we recorded goodwill impairment charges of $18 million related to our DCI reporting unit. During 2003, a DCI subsidiary received an unfavorable arbitration ruling that resulted in lower margins for services provided. Another DCI subsidiary experienced delays in expanding marketing and stabilizing production efforts. As a result of these unfavorable developments, we performed goodwill impairment tests, using

20

Notes to Consolidated Financial Statements, Continued

discounted cash flow analyses, which indicated that the goodwill associated with those entities was impaired.

Also in 2003, as described in Note 9, we purchased the remaining equity interest in DFV for $62 million, including $2 million for accrued dividends. This transaction was accounted for as a purchase of a minority interest and $60 million was recognized as goodwill and immediately impaired. The purchase enabled us to proceed with our strategy to sell Dominion Telecom.

Other Intangible Assets

All of our intangible assets, other than goodwill, are subject to amortization. Amortization expense for intangible assets was $130 million, $62 million and $54 million for 2005, 2004 and 2003, respectively. The acquisition of Dominion New England included certain emissions allowances that are classified as intangible assets. Approximately $245 million of the purchase price was allocated to these allowances. There were no other material acquisitions of intangible assets in 2005. In 2005, we sold certain Dominion New England emissions allowances with a carrying amount of $92 million. The components of our intangible assets are as follows:

At December 31,		**2005**		2004
	Gross Carrying Amount	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	**$ 613**	**$ 308**	$ 579	$ 269
Emissions allowances	**169**	**50**	12	4
Other	**225**	**30**	106	26
Total	**$ 1,007**	**$ 388**	$ 697	$ 299

Annual amortization expense for intangible assets is estimated to be $104 million for 2006, $92 million for 2007, $73 million for 2008, $64 million for 2009 and $38 million for 2010.

Note 14. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

At December 31,	**2005**	2004
(millions)		
Regulatory assets:		
Unrecovered gas costs	**$ 179**	$ 52
Regulatory assets current[1]	**179**	52
Income taxes recoverable through future rates[2]	**260**	250
Deferred cost of fuel used in electric generation[3]	**171**	248
Other postretirement benefit costs[4]	**80**	96
Customer bad debts[5]	**70**	73
RTO start-up costs and administration fees[6]	**47**	41
Termination of certain power purchase agreements[7]	**24**	
Other	**106**	80
Regulatory assets non-current	**758**	788
Total regulatory assets	**$ 937**	$ 840
Regulatory liabilities:		
Provision for future cost of removal[8]	**567**	595
Other[9]	**48**	30
Total regulatory liabilities	**$ 615**	$ 625

(1) Reported in other current assets.
(2) Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.
(3) In connection with the settlement of the 2003 Virginia fuel rate proceeding, we agreed to recover previously incurred costs through June 30, 2007 without a return on a portion of the unrecovered balance. Remaining costs to be recovered totaled $139 million at December 31, 2005.
(4) Costs recognized in excess of amounts included in regulated rates charged by our regulated gas operations before rates were updated to reflect a new method of accounting and the cost related to the accrued benefit obligation recognized as part of accounting for our acquisition of CNG.
(5) Instead of recovering bad debt costs through our base rates, the Public Utilities Commission of Ohio (Ohio Commission) allows us to recover all eligible bad debt expenses through a bad debt tracker. Annually, we assess the need to adjust the tracker based on the preceding year s unrecovered deferred bad debt expense. The Ohio Commission also has authorized the collection of previously deferred costs associated with certain uncollectible customer accounts from 2001 over five years through the tracker rider. Remaining costs to be recovered totaled $35 million at December 31, 2005.
(6) The Federal Energy Regulatory Commission (FERC) has conditionally authorized our deferral of start-up costs incurred in connection with joining an RTO and ongoing administrative fees paid to PJM. We have deferred $41 million in start-up costs and administration fees and $6 million of associated carrying costs. We expect recovery from Virginia jurisdictional retail customers to commence at the end of the Virginia retail rate cap period, subject to regulatory approval.
(7) The North Carolina Utilities Commission has authorized the deferral of previously incurred costs associated with the termination of certain long-term power purchase agreements with nonutility generators. The related costs are being amortized over the original term of each agreement.
(8) Rates charged to customers by our regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.
(9) Includes $8 million and $15 million reported in other current liabilities in 2005 and 2004, respectively.

At December 31, 2005, approximately $471 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of unrecovered gas costs, RTO start-up costs and administration fees, customer bad debts and a portion of deferred fuel costs. Unrecovered gas costs, the ongoing portion of bad debts and deferred fuel are recovered within two years. The previously deferred bad debts will be recovered over a 3-year period.

Note 15. Asset Retirement Obligations

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities and dismantlement and removal of gas and oil wells and platforms. However, in 2005 we recognized additional AROs due to the adoption of FIN 47, which clarified when sufficient information is available to reasonably estimate the fair value of conditional AROs. These additional AROs totaled $161 million and relate to interim retirements of natural gas gathering, transmission, distribution and storage pipeline components; the retirement of certain nonutility off shore natural gas pipelines; and the future abatement of asbestos in our generation facilities. These obligations result from certain safety and environmental activities we are required to perform when any pipeline is abandoned or asbestos is disturbed.

We also have AROs related to the retirement of the approximately 2,300 gas storage wells in our underground natural gas storage network, certain electric transmission and distribution assets located on property that we do not own, hydroelectric generation facilities and LNG processing and storage facilities. We currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets. Thus, AROs for these assets will not be reflected in our Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. Generally, this will

Notes to Consolidated Financial Statements, Continued

occur when the expected retirement or abandonment dates are determined by our operational planning. The changes to our AROs during 2005 were as follows:

(millions)	Amount
Asset retirement obligations at December 31, 2004[1]	$ 1,707
Obligations incurred during the period[2]	**337**
Obligations settled during the period	**(15)**
Accretion expense	**102**
Revisions in estimated cash flows	**(29)**
Obligations recognized upon adoption of FIN 47	**161**
Other	**(8)**
Asset retirement obligations at December 31, 2005[1]	**$ 2,255**

(1) Includes $2 million and $6 million reported in other current liabilities in 2004 and 2005, respectively.
(2) Approximately $309 million of the obligations incurred relate to the acquisition of Kewaunee.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2005 and 2004 the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $2.5 billion and $2.0 billion, respectively.

Note 16. Variable Interest Entities

FIN 46R addresses the consolidation of VIEs. An entity is considered a VIE under FIN 46R if it does not have sufficient equity to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

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

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

Certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered potential variable interests in the counterparties. Six potential VIEs, with which we have existing power purchase agreements (signed prior to December 31, 2003), have not provided sufficient information for us to perform our FIN 46R evaluation.

We have since determined that our interest in two of the potential VIEs is not significant. In addition, in May 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551 megawatt combined cycle facility located in Batesville, Mississippi, which was considered to be a potential VIE. We decided to divest our interest in the long-term power tolling contract in connection with our reconsideration of the scope of certain trading activities, including those conducted on behalf of our business segments, and our ongoing strategy to focus on business activities within the energy intensive Northeast, Mid-Atlantic and Midwest regions of the United States.

As of December 31, 2005, no further information has been received from the three remaining potential VIEs. We will continue our efforts to obtain information and will complete an evaluation of our relationship with each of these potential VIEs if sufficient information is ultimately obtained. We have remaining purchase commitments with these three potential VIE supplier entities of $2.0 billion at December 31, 2005. We paid $196 million, $199 million and $199 million for electric generation capacity and $243 million, $149 million and $134 million for electric energy to these entities for the years ended December 31, 2005, 2004 and 2003, respectively.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts with two potential variable interest entities. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately

$44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings. Total debt held by the entities is approximately $320 million. After completing our FIN 46R analysis, we concluded that although our interest in the contracts, as a result of their pricing terms, represent variable interests in these potential variable interest entities, we are not the primary beneficiary.

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

In accordance with FIN 46R, we consolidate certain variable interest lessor entities through which we have financed and leased several power generation projects. Our Consolidated Balance Sheets as of December 31, 2005 and 2004 reflect net property, plant and equipment of $943 million and $963 million, respectively and $1.1 billion of debt related to these entities. The debt is nonrecourse to us and is secured by the entities property, plant and equipment.

22

Notes to Consolidated Financial Statements, Continued

Note 17. Short-Term Debt and Credit Agreements

Joint Credit Facility

We use short-term debt, primarily commercial paper, to fund working capital requirements, as a bridge to long-term debt financing and as bridge financing for acquisitions, if applicable. The level of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, we utilize cash and letters of credit to fund collateral requirements under our commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels and the credit quality of our companies and their counterparties. In May 2005, we entered into a $2.5 billion five-year revolving credit facility that replaced our $1.5 billion three-year facility dated May 2004 and our $750 million three-year facility dated May 2002. This credit facility can also be used to support up to $1.25 billion of letters of credit. In February 2006, this facility was replaced by a $3.0 billion five-year credit facility that terminates in February 2011.

At December 31, 2005, total outstanding commercial paper supported by the joint credit facility was $1.6 billion, with a weighted average interest rate of 4.47%. At December 31, 2004, total outstanding commercial paper supported by previous credit agreements was $573 million, with a weighted average interest rate of 2.39%.

At December 31, 2005 and 2004, total outstanding letters of credit supported by joint credit facilities were $892 million and $183 million, respectively.

In January 2006, Virginia Power issued $450 million of 5.4% senior notes that mature in 2016 and $550 million of 6.0% senior notes that mature in 2036. Virginia Power used the proceeds from the issuance to repay short-term debt.

CNG Credit Facilities

In August 2005, CNG entered into a $1.75 billion five-year revolving credit facility that replaced its $1.5 billion three-year facility dated August 2004. The credit facility supports CNG s issuance of commercial paper and letters of credit to provide collateral required by counterparties on derivative financial contracts used by CNG in its risk management strategies for its gas and oil production. In February 2006, the facility limit was reduced to $1.70 billion. At December 31, 2005 and 2004, outstanding letters of credit under the facilities totaled $1.2 billion and $555 million, respectively.

We have also entered into several bilateral credit facilities in addition to the facilities previously discussed in order to provide collateral required on derivative contracts used in our risk management strategies for merchant generation and gas and oil production operations, respectively. Collateral requirements have increased significantly in 2005 as a result of escalating commodity prices. At December 31, 2005, we had the following letter of credit facilities:

Company	Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
(millions)					
CNG	$ 100	$ 100	$	June 2004	June 2007
CNG	100	100		August 2004	August 2009
CNG(1)	550	550		October 2004	April 2006
CNG(2)	1,900	625	1,275	August 2005	February 2006
CNG(3)	200		200	December 2005	December 2010
Dominion Resources, Inc.	150	150		September 2005	March 2006
Dominion Resources, Inc.	200	200		August 2005	February 2006
Dominion Resources, Inc.(4)	290	290		October 2005	April 2006
	$3,490	$2,015	$1,475		

(1) In February 2006, the facility limit was reduced to $150 million.
(2) In February 2006, CNG replaced this facility with a $1.05 billion 364-day credit facility.
(3) This facility can also be used to support commercial paper borrowings.
(4) In February 2006, the facility limit was reduced to $215 million.

23

Explanation of Responses:

Notes to Consolidated Financial Statements, Continued

Note 18. Long-Term Debt

At December 31, (millions, except percentages)	**2005 Weighted Average Coupon(1)**	**2005**	2004
Dominion Resources, Inc.:			
Unsecured Senior and Medium-Term Notes:			
2.25% to 8.125%, due 2005 to 2010	**5.13%**	**$ 3,212**	$ 3,002
5.0% to 7.82%, due 2012 to 2035 (2)	**5.82%**	**3,880**	2,880
Unsecured Equity-Linked Senior Notes, 5.75%, due 2008		**330**	330
Unsecured Convertible Senior Notes, 2.125%, due 2023(3)		**220**	220
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts, 7.83% to 8.4%, due 2027 to 2041	**8.22%**	**825**	825
Consolidated Natural Gas Company:			
Unsecured Debentures and Senior Notes:			
5.375% to 7.375%, due 2005 to 2010	**5.96%**	**1,050**	1,200
5.0% to 6.875%, due 2011 to 2027(2)	**6.19%**	**2,150**	2,150
Secured Bank Debt, Variable Rate, due 2006(4)	**3.87%**	**234**	234
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.8%, due 2041		**206**	206
Virginia Electric and Power Company:			
Secured First and Refunding Mortgage Bonds:(5)			
7.625%, due 2007		**215**	215
7.0% to 8.625%, due 2024 to 2025			512
Secured Bank Debt, Variable Rate, due 2007(4)	**3.76%**	**370**	370
Unsecured Senior and Medium-Term Notes:			
4.50% to 5.75%, due 2006 to 2010	**5.42%**	**1,600**	1,600
4.75% to 8.625%, due 2013 to 2032	**5.51%**	**762**	706
Unsecured Callable and Puttable Enhanced Securities^{SM}, 4.10%, due 2038(6)		**225**	225
Tax-Exempt Financings:(7)			
Variable Rate, due 2008	**2.62%**	**60**	60
Variable Rates, due 2015 to 2027	**2.61%**	**137**	137
4.95% to 9.62%, due 2005 to 2010	**5.54%**	**237**	242
2.30% to 7.55%, due 2014 to 2031	**5.02%**	**263**	263
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		**412**	412
Dominion Energy, Inc.:			
Unsecured Medium-Term Notes, 4.92% to 6.1%, due 2005 to 2009(8)			453
Secured Senior Note, 7.33%, due 2020		**222**	231
Secured Bank Debt, Variable Rates, due 2006(4)	**3.87%**	**347**	347
Dominion Capital, Inc.:			
Notes, 12.5%, due 2006 to 2008		**6**	6
Dominion Resources Services, Inc., Secured Bank Debt, Variable Rate, due 2006(4)	**4.20%**	**107**	107
		17,070	16,933
Fair value hedge valuation(9)		**(52)**	11
Amounts due within one year	**4.69%**	**(2,330)**	(1,368)
Unamortized discount and premium, net		**(35)**	(69)
Total long-term debt		**$ 14,653**	$ 15,507

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2005.

(2) At the option of holders in October 2006 and August 2015, $150 million of CNG s 6.875% senior notes due 2026 and $510 million of Dominion s 5.25% senior notes due 2033, respectively, are subject to redemption at 100% of the principal amount plus accrued interest. In the event of an early redemption, we have the intent and ability to refinance CNG s 6.875% senior notes under our long-term credit facilities. Accordingly, CNG s 6.875% senior notes remain classified as long-term debt on our Consolidated Balance Sheets.

(3) Convertible into a combination of cash and shares of our common stock at any time after March 31, 2004 when the average closing price of our common stock reaches $88.32 per share for a specified period. At the option of holders on December 15, 2006, December 15, 2008, December 15, 2013, or December 15, 2018, these securities are subject to redemption at 100% of the principal amount plus accrued interest. In the event of an early redemption, we have the intent and ability to refinance this security under our long-term credit facilities. Accordingly, this security remains classified as long-term debt on our Consolidated Balance Sheets.

(4) Represents debt associated with certain special purpose lessor entities that are consolidated in accordance with FIN 46R. The debt is nonrecourse to us and is secured by the entities property, plant and equipment, which totaled $943 million and $963 million at December 31, 2005 and 2004, respectively.

(5) Substantially all of Virginia Power s property ($12.3 billion at December 31, 2005) is subject to the lien of the mortgage, securing its mortgage bonds. Due to the early redemption of $512 million of First and Refunding Mortgage Bonds in 2005, we incurred $25 million of prepayment penalties and related charges that were recognized in interest expense on our Consolidated Statement of Income.

(6) On December 15, 2008, $225 million of the 4.10% Callable and Puttable Enhanced Securities[SM] due 2038 are subject to redemption at par plus accrued interest, unless holders of related options exercise rights to purchase and remarket the notes.

(7) Certain pollution control equipment at Virginia Power s generating facilities has been pledged to support these financings. The variable rate tax-exempt financings are supported by a stand-alone $200 million three-year credit facility that terminates in May 2006. In February 2006 this facility was replaced with a five-year credit facility that terminates in February 2011.

(8) Aggregate principal amount of CAD$545 million of securities denominated in Canadian dollars and presented in US dollars, based on exchange rates as of year-end.

(9) Represents changes in fair value of certain fixed-rate long-term debt associated with fair value hedging relationships.

24

Notes to Consolidated Financial Statements, Continued

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2005 were as follows:

(millions, except percentages)	2006	2007	2008	2009	2010	Thereafter	Total
Secured First and Refunding Mortgage Bonds		$ 215					$ 215
Secured Senior Notes	$ 9	9	$ 10	$ 11	$ 12	$ 171	222
Unsecured Callable and Puttable Enhanced Securities[SM]						225	225
Tax-Exempt Financings	5	20	157	115	5	396	698
Secured Bank Debt	688	370					1,058
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts						1,443	1,443
Unsecured Senior Notes (including Medium-Term Notes)	1,626	1,863	1,013	313	1,444	6,944	13,203
Other	2		4				6
Total	$ 2,330	$ 2,477	$ 1,184	$ 439	$ 1,461	$ 9,179	$ 17,070
Weighted average coupon	4.69%	5.05%	5.18%	5.38%	6.56%	6.02%	

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2005, there were no events of default under these covenants.

Convertible Securities

As described in Note 3, we entered into an exchange transaction with respect to $219 million of our outstanding contingent convertible senior notes in contemplation of the transition method provided by EITF 04-8. We exchanged the outstanding notes for new notes with a conversion feature that requires that the principal amount of each note be repaid in cash. The notes are valued at a conversion rate of 13.5865 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $73.60. Amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases.

The new notes outstanding on December 31, 2004 were included in the diluted EPS calculation retroactive to the date of their issuance using the method described in EITF 04-8. Under this method, the number of shares included in the denominator of the diluted EPS calculation is calculated as the net shares issuable for the reporting period based upon the average market price for the period. This did not result in an increase to the average shares outstanding used in the calculation of our diluted EPS since the conversion price of $73.60 included in the notes was greater than the average market price of the shares.

The senior notes are convertible by holders into a combination of cash and shares of our common stock under any of the following circumstances:

(1) the price of our common stock reaches $88.32 per share for a specified period;
(2) the senior notes are called for redemption by us on or after December 20, 2006;
(3) the occurrence of specified corporate transactions; or
(4) the credit rating assigned to the senior notes by Moody s Investors Service is below Baa3 and by Standard & Poor s Rating Group, a division of the McGraw-Hill Companies, Inc., is below BBB- or the ratings are discontinued for any reason.

Since none of the conditions have been met, the senior notes are not yet subject to conversion. In 2007, we will also begin to pay contingent interest if the average trading price as defined in the indenture equals or exceeds 120% of the principal amount of the senior notes. Holders have the right to require us to purchase our senior notes for cash at 100% of the principal amount plus accrued interest in December 2006, 2008, 2013 or 2018, or if we undergo certain fundamental changes.

Equity Linked Securities

In 2002 and 2000, we issued equity-linked debt securities, consisting of stock purchase contracts and senior notes. The stock purchase contracts obligate the holders to purchase shares of our common stock from us by a settlement date, two years prior to the senior notes maturity date. The purchase price is $50 and the number of shares to be purchased will be determined under a formula based upon the average closing price of our common stock near the settlement date. The senior notes, or treasury securities in some instances, are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts. The holders may satisfy their obligations under the stock purchase contracts by allowing the senior notes to be remarketed with the proceeds being paid to us as consideration for the purchase of stock. Alternatively, holders may choose to continue holding the senior notes and use other resources as consideration for the purchase of stock under the stock purchase contracts.

We make quarterly interest payments on the senior notes and quarterly payments on the stock purchase contracts at the rates presented in the following table. We have recorded the present value of the stock purchase contract payments as a liability, offset by a charge to common stock in shareholders equity. Interest payments on the senior notes are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as interest expense. In calculating diluted EPS, we apply the treasury stock method to the equity-linked debt securities. These securities did not have a significant effect on diluted EPS for 2005, 2004 or 2003.

Under the terms of the stock purchase contracts, we issued 6.7 million shares of our common stock in November 2004 and

Notes to Consolidated Financial Statements, Continued

will issue between 4.1 million and 5.5 million shares of our common stock in May 2006. Sufficient shares of our common stock have been reserved for issuance in connection with the May 2006 stock purchase contracts.

Selected information about our equity-linked debt securities is presented below:

Date of Issuance	Units Issued	Total Net Proceeds	Total Long-term Debt	Senior Notes Annual Interest Rate	Stock Purchase Contract Annual Rate	Total Equity Charge	Stock Purchase Settlement Date	Maturity of Senior Notes
(millions, except percentages)								
2000	8.3	$ 400.1	$ 412.5	3.66%[1]	%[2]	$ 20.7	11/04	11/06
2002	6.6	$ 320.1	$ 330.0	5.75%	3.00%	$ 36.3	5/06	5/08

(1) Prior to their remarketing in November 2004, the senior notes carried an annual interest rate of 8.05%.
(2) The stock purchase contracts carried an annual interest rate of 1.45% prior to their settlement in November 2004.

Junior Subordinated Notes Payable to Affiliated Trusts

From 1997 through 2002, we established five subsidiary capital trusts, each as a finance subsidiary of the respective parent company, which holds 100% of the voting interests. The capital trusts sold trust preferred securities representing preferred beneficial interests and 97% beneficial ownership in the assets held by the capital trusts. In exchange for the funds realized from the sale of the trust preferred securities and common securities that represent the remaining 3% beneficial ownership interest in the assets held by the capital trusts, we issued various junior subordinated notes. The junior subordinated notes constitute 100% of each capital trust s assets. Each trust must redeem its trust preferred securities when their respective junior subordinated notes are repaid at maturity or if redeemed prior to maturity.

Under previous accounting guidance, we consolidated the trusts in the preparation of our Consolidated Financial Statements. In accordance with FIN 46R, we ceased to consolidate the trusts as of December 31, 2003 and instead report as long-term debt on our Consolidated Balance Sheet the junior subordinated notes issued by us and held by the trusts.

The following table provides summary information about the trust preferred securities and junior subordinated notes outstanding as of December 31, 2005:

Date Established	Capital Trusts	Units	Rate	Trust Preferred Securities Amount	Common Securities Amount
		(thousands)			(millions)
December 1997	Dominion Resources Capital Trust I[1]	250	7.83%	$ 250	$ 8
January 2001	Dominion Resources Capital Trust II[2]	12,000	8.4%	300	9
January 2001	Dominion Resources Capital Trust III[3]	250	8.4%	250	8
October 2001	Dominion CNG Capital Trust I[4]	8,000	7.8%	200	6
August 2002	Virginia Power Capital Trust II[5]	16,000	7.375%	400	12

Junior subordinated notes/debentures held as assets by each capital trust were as follows:

(1) $258 million Dominion Resources, Inc. 7.83% Debentures due 12/1/2027.
(2) $309 million Dominion Resources, Inc. 8.4% Debentures due 1/30/2041.
(3) $258 million Dominion Resources, Inc. 8.4% Debentures due 1/15/2031.
(4) $206 million CNG 7.8% Debentures due 10/31/2041.

(5) $412 million Virginia Power 7.375% Debentures due 7/30/2042.

Distribution payments on the trust preferred securities are considered to be fully and unconditionally guaranteed by the respective parent company that issued the debt instruments held by each trust, when all of the related agreements are taken into consideration. Each guarantee agreement only provides for the guarantee of distribution payments on the relevant trust preferred securities to the extent that the trust has funds legally and immediately available to make distributions. The trust s ability to pay amounts when they are due on the trust preferred securities is solely dependent upon the payment of amounts by Dominion, Virginia Power or CNG when they are due on the junior subordinated debt instruments. If the payment on the junior subordinated notes is deferred, the company that issued them may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, the company that issued them may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the junior subordinated notes.

26

Notes to Consolidated Financial Statements, Continued

Note 19. Subsidiary Preferred Stock

Dominion is authorized to issue up to 20 million shares of preferred stock. At December 31, 2005 and 2004, none were issued and outstanding.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. At December 31, 2005 and 2004, Virginia Power had 2.59 million preferred shares issued and outstanding. Upon involuntary liquidation, dissolution or winding-up of Virginia Power, each share would be entitled to receive $100 plus accrued dividends. Dividends are cumulative.

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

Presented below are the series of Virginia Power preferred stock not subject to mandatory redemption that were outstanding as of December 31, 2005:

Dividend	Issued and Outstanding Shares (thousands)	Entitled Per Share Upon Liquidation
$5.00	107	$ 112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.82(1)
6.98	600	102.80(2)
Flex MMP 12/02, Series A	1,250	100.00(3)
Total	2,590	

(1) Through 7/31/06; $102.47 commencing 8/1/06; amounts decline in steps thereafter to $100.00 by 8/1/13.
(2) Through 8/31/06; $102.45 commencing 9/1/06; amounts decline in steps thereafter to $100.00 by 9/1/13.
(3) Dividend rate is 5.50% through 12/20/07; after which the rate will be determined according to periodic auctions for periods established by Virginia Power at the time of the auction process. This series is not callable prior to 12/20/07.

Note 20. Shareholders Equity

Issuance of Common Stock

In 2005, we received proceeds of $345 million for 5.8 million shares issued through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. In February 2005, Dominion Direct® and the Dominion employee savings plans began purchasing our common stock on the open market with the proceeds received through these programs, rather than having additional new common shares issued.

Repurchases of Common Stock

In February 2005, we were authorized by our Board of Directors to repurchase up to the lesser of 25 million shares, or $2.0 billion of our outstanding common stock. As of December 31, 2005, we had repurchased approximately 3.7 million shares for approximately $276 million.

Forward Equity Transaction

In September 2004, we entered into a forward equity sale agreement (forward agreement) with Merrill Lynch International (MLI), as forward purchaser, relating to 10 million shares of our common stock. The forward agreement provided for the sale of two tranches of our common stock, each with stated maturity dates and settlement prices. In connection with the forward agreement, MLI borrowed an equal number of shares of our common stock from stock lenders and, at our request, sold the borrowed shares to J.P. Morgan Securities Inc. (JPM) under a purchase agreement among Dominion, MLI and JPM. JPM subsequently offered the borrowed shares to the public. We accounted for the forward agreement as equity at its initial fair value but did not receive any proceeds from the sale of the borrowed shares.

The use of a forward agreement allowed us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds were needed. Except in specified circumstances or events that would have required physical share settlement, we were able to elect to settle the forward agreement by means of a physical share, cash or net share settlement and were also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under either a physical share or net share settlement, the maximum number of shares that were deliverable under the terms of the forward agreement was limited to the 10 million shares specified in the two tranches. Assuming gross share settlement of all shares under the forward agreement, we would have received aggregate proceeds of approximately $644 million, based on maturity forward prices of $64.62 per share for the 2 million shares included in the first tranche and $64.34 per share for the 8 million shares included in the second tranche.

We elected to cash settle the first tranche in December 2004 and paid MLI $5.8 million, representing the difference between our share price and the applicable forward sale price, multiplied by the 2 million shares. Additionally, we elected to cash settle 3 million shares of the second tranche in February 2005 and paid MLI $17.4 million. We recorded the settlement payments as a reduction to common stock in our Consolidated Balance Sheets.

In April 2005, we entered into an agreement with MLI that extended the settlement date for the remaining 5 million shares of the second tranche to August 2005. In August 2005, we delivered 5 million newly issued shares of our common stock to MLI, and received proceeds of $319.7 million as final settlement of the forward agreement.

Shares Reserved for Issuance

At December 31, 2005, we had a total of 37 million shares reserved and available for issuance for the following: Dominion Direct®, employee stock awards, employee savings plans, director stock compensation plans, and stock purchase contracts associated with equity-linked debt securities.

Notes to Consolidated Financial Statements, Continued

Accumulated Other Comprehensive Income (Loss)

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

At December 31, (millions)	**2005**	2004
Net unrealized losses on derivatives hedging activities	**$ (2,777)**	$ (1,181)
Net unrealized gains on investment securities	**165**	149
Minimum pension liability adjustment	**(10)**	(14)
Foreign currency translation adjustments	**58**	50
Total accumulated other comprehensive loss	**$ (2,564)**	$ (996)

Stock-Based Awards

In April 2005, shareholders approved the 2005 Incentive Compensation Plan (2005 Incentive Plan) for employees and the Non-Employee Directors Compensation Plan (Non-Employee Directors Plan). Both plans permit stock-based awards that include restricted stock, goal-based stock, stock options and stock appreciation rights under the 2005 Incentive Plan and restricted stock and stock options under the Non-Employee Directors Plan. Under provisions of both plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms would be set at the discretion of either the Organization, Compensation and Nominating Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At December 31, 2005, approximately 15.3 million shares were available for future grants under these plans. Prior to April 2005, we had an incentive compensation plan that provided stock options and restricted stock awards to directors, executives and other key employees with vesting periods from one to five years. Stock options generally had contractual terms from six and one half to ten years.

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2005, 2004 and 2003. No options were granted under any plan in 2005, 2004 or 2003.

	Stock Options (thousands)	**Weighted-average Exercise Price**
Outstanding at December 31, 2002	21,057	$ 55.49
Exercisable at December 31, 2002	8,586	$ 47.95
Exercised, cancelled and forfeited	(2,513)	$ 44.39
Outstanding at December 31, 2003	18,544	$ 56.97
Exercisable at December 31, 2003	11,604	$ 54.44
Exercised, cancelled and forfeited	(4,736)	$ 47.67
Outstanding at December 31, 2004	13,808	$ 60.17
Exercisable at December 31, 2004	10,768	$ 60.01
Exercised, cancelled and forfeited	**(5,594)**	**$ 59.79**
Outstanding at December 31, 2005	**8,214**	**$ 60.43**
Exercisable at December 31, 2005	**8,214**	**$ 60.43**

The following table provides certain information about stock options outstanding as of December 31, 2005:

		Options Outstanding		Options Exercisable	
Exercise Price	**Shares Outstanding**	**Weighted-average Remaining Contractual**	**Weighted-average Exercise Price**	**Shares Exercisable**	**Weighted-average Exercise Price**

	(thousands)	Life (years)		(thousands)	
$ 0-$19.99	1	3.0	$ 19.10	1	$ 19.10
$20-$30.99	17	3.1	$ 24.62	17	$ 24.62
$31-$40.99	30	4.0	$ 39.25	30	$ 39.25
$41-$50.99	770	4.9	$ 46.20	770	$ 46.20
$51-$60.99	4,483	3.4	$ 59.93	4,483	$ 59.93
$61-$69	2,913	5.3	$ 65.38	2,913	$ 65.38
Total	8,214	4.2	$ 60.43	8,214	$ 60.43

During 2005, 2004 and 2003, respectively, we granted approximately 249,000 shares, 582,000 shares, and 402,000 shares of restricted stock with weighted-average fair values of $74.51, $63.29 and $56.08.

Note 21. Dividend Restrictions

The Public Utility Holding Company Act of 1935 (1935 Act) and related regulations issued by the SEC impose restrictions on the transfer and receipt of funds by a registered holding company from its subsidiaries, including a general prohibition against loans or advances being made by the subsidiaries to benefit the registered holding company. Under the 1935 Act, registered holding companies and their subsidiaries may pay dividends only from retained earnings, unless the SEC specifically authorizes payments from other capital accounts. We received dividends from our subsidiaries of $1.2 billion, $1.2 billion and $1.1 billion in 2005, 2004 and 2003, respectively.

At December 31, 2005, our consolidated subsidiaries had approximately $10.5 billion in capital accounts other than retained earnings, representing capital stock, other paid-in capital and AOCI. Dominion Resources, Inc. had approximately $8.8 billion in capital accounts other than retained earnings at December 31, 2005. Generally, such amounts are not available for the payment of dividends by affected subsidiaries, or by Dominion itself, without specific authorization by the SEC.

In response to a Dominion request, the SEC granted relief in 2000; authorizing payment of dividends by CNG from other capital accounts to Dominion in amounts of up to $1.6 billion, representing CNG s retained earnings prior to our acquisition of CNG. The SEC granted further relief in 2004, authorizing our nonutility subsidiaries to pay dividends out of capital or unearned surplus in situations where such subsidiary has received excess cash from an asset sale, engaged in a restructuring, or is returning capital to an associate company. Our ability to pay dividends on our common stock at declared rates was not impacted by the restrictions previously discussed during 2005, 2004 and 2003. We are not bound by the foregoing restrictions on dividends imposed by the 1935 Act as of February 8, 2006, the effective date on which the 1935 Act was repealed under the Energy Policy Act of 2005.

28

Notes to Consolidated Financial Statements, Continued

The Virginia State Corporation Commission (Virginia Commission) may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate, if found not to be in the public interest. At December 31, 2005, the Virginia Commission had not restricted the payment of dividends by Virginia Power.

Certain agreements associated with our credit facilities contain restrictions on the ratio of our debt to total capitalization. These limitations did not restrict our ability to pay dividends or receive dividends from our subsidiaries at December 31, 2005.

See Note 18 for a description of potential restrictions on dividend payments by us and certain of our subsidiaries in connection with the deferral of distribution payments on trust preferred securities.

Note 22. Employee Benefit Plans

We provide certain benefits to eligible active employees, retirees and qualifying dependents. Under the terms of our benefit plans, we reserve 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.

We maintain qualified noncontributory defined benefit pension plans covering virtually all employees. Retirement benefits are based primarily on years of service, age and compensation. Our funding policy is to generally contribute annually an amount that is in accordance with the provisions of the Employment Retirement Income Security Act of 1974. The pension program also provides benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. Certain of these nonqualified plans are funded through contributions to a grantor trust.

We provide retiree health care and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service. In 2004, we amended our non-union retiree health care and life insurance plans. In connection with the amendment, eligible employees under age fifty-five share more of the costs of benefits with us, and certain retiree medical benefits were enhanced. We re-measured our accumulated postretirement benefit obligation (APBO) during the third quarter of 2004 and as a result reduced the liability by $59 million. The impact of re-measurement on our 2004 postretirement net periodic benefits cost was not material. We will amortize the unrecognized actuarial gains associated with the plan amendment over the average remaining service period of plan participants in accordance with SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act) was signed into law. The Medicare Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Based on an analysis performed by a third-party actuary, we have determined that the prescription drug benefit offered under our other postretirement benefit plans is at least actuarially equivalent to Medicare Part D and therefore we expect to receive the federal subsidy offered under the Medicare Act.

We expect to receive subsidies of approximately $4 million, $5 million, $5 million, $6 million and $7 million for the years 2006, 2007, 2008, 2009 and 2010 respectively, and expect to receive approximately $50 million during the period 2011 through 2015. We considered the passage of the Medicare Act a significant event requiring remeasurement of our APBO on December 8, 2003. We will amortize the unrecognized actuarial gains associated with the benefits of the subsidy over the average remaining service period of plan participants in accordance with SFAS No. 106.

We use December 31 as the measurement date for virtually all of our employee benefit plans. We use the market-related value of pension plan assets to determine the expected return on pension plan assets, a component of net periodic pension cost. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses.

Notes to Consolidated Financial Statements, Continued

The following table summarizes the changes in our pension and other postretirement benefit plan obligations and plan assets and includes a statement of the plans funded status:

Year Ended December 31, (millions)	Pension Benefits **2005**	Pension Benefits 2004	Other Postretirement Benefits **2005**	Other Postretirement Benefits 2004
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 3,410**	$ 3,110	**$ 1,381**	$ 1,351
Acquisitions	**15**		**44**	
Service cost	**110**	97	**64**	63
Interest cost	**201**	190	**83**	83
Benefits paid	**(142)**	(143)	**(67)**	(68)
Actuarial loss during the year	**231**	143	**143**	11
Plan amendments	**9**	13	**(26)**	(59)
Benefit obligation at end of year	**3,834**	3,410	**1,622**	1,381
Change in plan assets:				
Fair value of plan assets at beginning of year	**4,049**	3,734	**697**	587
Acquisitions	**15**		**10**	
Actual return on plan assets	**433**	453	**51**	60
Contributions	**5**	5	**72**	85
Benefits paid from plan assets	**(142)**	(143)	**(36)**	(35)
Fair value of plan assets at end of year	**4,360**	4,049	**794**	697
Funded status	**526**	639	**(828)**	(684)
Unrecognized net actuarial loss	**1,288**	1,225	**491**	366
Unrecognized prior service cost (credit)	**34**	28	**(32)**	(7)
Unrecognized net transition obligation			**23**	27
Prepaid (accrued) benefit cost	**$ 1,848**	$ 1,892	**$ (346)**	$ (298)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid pension cost	**$ 1,915**	$ 1,947		
Accrued benefit liability	**(115)**	(94)	**$ (346)**	$ (298)
Intangible asset	**31**	15		
Accumulated other comprehensive loss	**17**	24		
Net amount recognized	**$ 1,848**	$ 1,892	**$ (346)**	$ (298)

The accumulated benefit obligation for all of our defined benefit pension plans was $3.3 billion and $3.0 billion at December 31, 2005 and 2004, respectively. Under our funding policies, we evaluate plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from our actuary. Based on the funded status of each plan and other factors, we determine the amount of contributions for the current year, if any, at that time.

Included above are nonqualified and supplemental pension plans that do not have plan assets as defined by generally accepted accounting principles. The total projected benefit obligation for these plans was $134 million and $112 million at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for these plans was $118 million and $97 million at December 31, 2005 and 2004, respectively. Because the accumulated benefit obligation relating to these plans is in excess of the fair value of plan assets, we recognized an additional minimum liability of $48 million and $39 million at December 31, 2005 and 2004, respectively.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(millions)	Pension Benefits	Other Postretirement Benefits
2006	$ 188	$ 74

2007	161	80
2008	161	86
2009	167	91
2010	196	97
2011-2015	1,176	580

30

Notes to Consolidated Financial Statements, Continued

Our overall objective for investing our pension and other postretirement plan assets is to achieve the best possible long-term rates of return commensurate with prudent levels of risk. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocation for our pension fund is 45% U.S. equity securities; 8% non-U.S. equity securities; 22% debt securities; and 25% other, such as real estate and private equity investments. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities. The asset allocations for our pension plans and other postretirement plans follow:

			Pension Plans				Other Postretirement Plans	
Year Ended December 31,		**2005**		2004		**2005**		2004
	Fair Value	**% of Total**	Fair Value	% of Total	**Fair Value**	**% of Total**	Fair Value	% of Total
(millions)								
Equity securities:								
U.S.	**$ 1,750**	**40**	$ 1,761	44	**$ 330**	**42**	$ 308	44
International	**607**	**14**	522	13	**90**	**11**	74	11
Debt securities	**990**	**23**	947	23	**289**	**36**	250	36
Real estate	**340**	**8**	298	7	**21**	**3**	17	2
Other	**673**	**15**	521	13	**64**	**8**	48	7
Total	**$ 4,360**	**100**	$ 4,049	100	**$ 794**	**100**	$ 697	100

The components of the provision for net periodic benefit cost were as follows:

		Pension Benefits			Other Postretirement Benefits	
Year Ended December 31,	**2005**	2004	2003	**2005**	2004	2003
(millions)						
Service cost	**$ 110**	$ 97	$ 86	**$ 64**	$ 63	$ 55
Interest cost	**201**	190	182	**83**	83	79
Expected return on plan assets	**(341)**	(336)	(332)	**(51)**	(44)	(33)
Amortization of prior service cost (credit)	**3**	2	2	**(1)**		
Amortization of transition obligation (asset)			(2)	**3**	7	9
Amortization of net loss	**77**	56	20	**19**	21	20
Net periodic benefit cost (credit)	**$ 50**	$ 9	$ (44)	**$ 117**	$ 130	$ 130

Significant assumptions used in determining the net periodic cost recognized in our Consolidated Statements of Income were as follows, on a weighted-average basis:

		Pension Benefits			Other Postretirement Benefits	
Year Ended December 31,	**2005**	2004	2003	**2005**	2004	2003
Discount rate	**6.00%**	6.25%	6.75%	**6.00%**	6.25%	6.75%
Expected return on plan assets	**8.75%**	8.75%	8.75%	**8.00%**	7.79%	7.78%
Rate of increase for compensation	**4.70%**	4.70%	4.70%	**4.70%**	4.70%	4.70%
Medical cost trend rate(1)				**9.00%**	9.00%	9.00%

(1) Decreasing to 5.00% in 2009 and years thereafter.

Significant assumptions used in determining the projected pension benefit and postretirement benefit obligations recognized in our Consolidated Balance Sheets were as follows, on a weighted-average basis:

	Pension Benefits	Other

			Postretirement Benefits	
At December 31,	**2005**	2004	**2005**	2004
Discount rate	**5.60%**	6.00%	**5.50%**	6.00%
Rate of increase for compensation	**4.70%**	4.70%	**4.70%**	4.70%

We determine the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Historical return analysis to determine expected future risk premiums;
- Forward-looking return expectations derived from the yield on long-term bonds and the price earnings ratios of major stock market indices;
- Expected inflation and risk-free interest rate assumptions; and
- The types of investments expected to be held by the plans.

Assisted by an independent actuary, management develops assumptions, which are then compared to the forecasts of other independent investment advisors to ensure reasonableness. An internal committee selects the final assumptions.

Discount rates are determined from analyses performed by a third-party actuarial firm of AA/Aa rated bonds with cash flows matching the expected payments to be made under our plans.

Notes to Consolidated Financial Statements, Continued

Assumed health care cost trend rates have a significant effect on the amounts reported for our retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have had the following effects:

	Other Postretirement Benefits One percentage point increase		Other Postretirement Benefits One percentage point decrease	
(millions)				
Effect on total service and interest cost components for 2005	$	26	$	(20)
Effect on postretirement benefit obligation at December 31, 2005	$	220	$	(179)

In addition, we sponsor defined contribution thrift-type savings plans. During 2005, 2004 and 2003, we recognized $33 million, $29 million and $27 million, respectively, as contributions to these plans.

Certain regulatory authorities have held that amounts recovered in utility customers rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of our subsidiaries fund postretirement benefit costs through Voluntary Employees Beneficiary Associations. Our remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented.

Note 23. Commitments and Contingencies

As the result of issues generated in the ordinary course of business, we are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings will not have a material effect on our financial position, liquidity or results of operations.

Long-Term Purchase Agreements

At December 31, 2005, we had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

	2006	2007	2008	2009	2010	Thereafter		Total
(millions)								
Purchased electric capacity[(1)]	$ 441	$ 418	$ 387	$ 366	$ 352	$	2,536	$ 4,500
Production handling for gas and oil production operations[(2)]	54	51	36	22	14		13	190

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2023. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2005, the present value of our total commitment for capacity payments is $2.8 billion. Capacity payments totaled $472 million, $570 million and $611 million, and energy payments totaled $378 million, $293 million and $289 million for 2005, 2004, and 2003, respectively.

(2) Payments under this contract, which ends in 2012, totaled $52 million, $22 million and $10 million in 2005, 2004 and 2003, respectively.

In the first quarter of 2005, we paid $42 million in cash and assumed $62 million of debt in connection with the termination of a long-term power purchase agreement and the acquisition of the related generating facility used by Panda-Rosemary LP, a nonutility generator, to provide electricity to us. The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as of the date of acquisition. In connection with the termination of the agreement, we recorded an after-tax charge of $47 million.

In the second quarter of 2005, we paid $215 million to divest our interest in a long-term power tolling contract with a 551-megawatt combined cycle facility located in Batesville, Mississippi. We recorded after-tax charges of $8 million and $112 million in 2005 and 2004, respectively, related to the divestiture of the contract.

In October 2005, we reached an agreement in principle to restructure three long-term power purchase contracts. The restructured contracts expire between 2015 and 2017 and are expected to reduce capacity and energy payments by approximately $44 million and $6 million, respectively, over the remaining term of the contracts. The transaction became effective in February 2006 and did not result in a cash outlay or charge to earnings.

Lease Commitments

We lease various facilities, onshore and offshore drilling rigs, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2005 are as follows:

2006	2007	2008	2009	2010	Thereafter	Total
(millions)						
$131	$ 142	$ 142	$ 132	$ 106	$ 345	$ 998

Rental expense totaled $160 million, $123 million and $105 million for 2005, 2004 and 2003, respectively, the majority of which is reflected in other operations and maintenance expense.

We have an agreement with a voting interest entity (lessor) to lease the Fairless Energy power station in Pennsylvania (Fairless), which began commercial operations in June 2004. During construction, we acted as the construction agent for the lessor, controlled the design and construction of the facility and have since been reimbursed for all project costs ($898 million) advanced to the lessor. We make annual lease payments of $53 million, that are reflected in the lease commitments table. The lease expires in 2013 and at that time, we may renew the lease at negotiated amounts based on original project costs and current market conditions, subject to lessor approval; purchase Fairless at its original construction cost; or sell Fairless, on behalf of the lessor, to an independent third party. If Fairless is sold and the proceeds from the sale are less than its original construction cost, we would be required to make a payment to the lessor in an amount up to 70.75% of the original project costs adjusted for certain other costs as specified in the lease. The lease agreement does not contain any provisions that involve credit rating or stock price trigger events.

Notes to Consolidated Financial Statements, Continued

Environmental Matters

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

Historically, we recovered such costs arising from regulated electric operations through utility rates. However, to the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2010, in excess of the level currently included in Virginia jurisdictional rates, our results of operations will decrease. After that date, we may seek recovery through rates of only those environmental costs related to our transmission and distribution operations.

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

In 1987, we and a number of other entities were identified by the EPA as PRPs at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Remediation design is complete for the Pennsylvania site, and total remediation costs are expected to be in the range of $13 million to $25 million. Based on allocation formulas and the volume of waste shipped to the site, we have accrued a reserve of $2 million to meet our obligations at these two sites. Based on a financial assessment of the PRPs involved at these sites, we have determined that it is probable that the PRPs will fully pay their share of the costs. We generally seek to recover our costs associated with environmental remediation from third-party insurers. At December 31, 2005, any pending or possible insurance claims were not recognized as an asset or offset against obligations.

Other Before being acquired by us in 2001, Louis Dreyfus Natural Gas Corp. (Louis Dreyfus) was one of numerous defendants in a lawsuit consolidated and pending in the 93rd Judicial District Court in Hidalgo County, Texas. The lawsuit alleges that gas wells and related pipeline facilities operated by Louis Dreyfus and facilities operated by other defendants caused an underground hydrocarbon plume in McAllen, Texas. The plaintiffs claim that they have suffered damages, including property damage and lost profits, as a result of the alleged plume. Although the results of litigation are inherently unpredictable, we do not expect the ultimate outcome of the case to have a material adverse impact on our results of operations, cash flows or financial position.

We have determined that we are associated with 21 former manufactured gas plant sites. Studies conducted by other utilities at their former manufactured gas plants have indicated that their sites contain coal tar and other potentially harmful materials. None of the 21 former sites with which we are associated is under investigation by any state or federal environmental agency, and no investigation or action is currently anticipated. One of the former sites is conducting a state approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Regarding the other sites, it is not known to what degree these sites may contain environmental contamination. We are not able to estimate the cost, if any, that may be required for the possible remediation of these other sites.

Nuclear Operations

Nuclear Decommissioning Minimum Financial Assurance The Nuclear Regulatory Commission (NRC) requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Our 2005 NRC minimum financial assurance amount, aggregated for our nuclear units, was $2.9 billion and has been satisfied by a combination of the funds being collected and deposited in the trusts and the real annual rate of return growth of the funds allowed by the NRC. In June 2005, we gave notice to the NRC that we were canceling our previous guarantee related to the nuclear units at Virginia Power and two nuclear units at Millstone. These guarantees were cancelled because, based on our calculations, the trusts now contain sufficient funds to meet NRC requirements without further assurances.

Nuclear Insurance The Price-Anderson Act provides the public up to $10.8 billion of protection per nuclear incident via obligations required of owners of nuclear power plants. The Price-Anderson Act Amendment of 1988 allows for an inflationary provision adjustment every five years. We have purchased $300 million of coverage from the commercial insurance pools with the remainder provided through a mandatory industry risk-sharing program. With the acquisition of Kewaunee in July 2005, we have seven licensed reactors. In the event of a nuclear incident at any licensed nuclear reactor in the United States, we could be assessed up to $100.6 million for each of our seven licensed reactors not to exceed $15 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. The Price-Anderson Act was first enacted in 1957 and was renewed again in 2005.

Our current level of property insurance coverage ($2.55 billion for North Anna, $2.55 billion for Surry, $2.75 for Millstone, and $1.8 billion for Kewaunee) exceeds the NRC s minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site and includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first to return the reactor to and maintain it in a safe and stable condition and second to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Our nuclear property insurance is provided by the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. The maximum assessment for the current policy period is $99

33

Notes to Consolidated Financial Statements, Continued

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

We purchase insurance from NEIL to cover the cost of replacement power during the prolonged outage of a nuclear unit due to direct physical damage of the unit. Under this program, we are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. The current policy period s maximum assessment is $35 million.

Old Dominion Electric Cooperative, a part owner of North Anna Power Station, and Massachusetts Municipal Wholesale Electric Company and Central Vermont Public Service Corporation, part owners of Millstone s Unit 3, are responsible for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

Spent Nuclear Fuel Under provisions of the Nuclear Waste Policy Act of 1982, we have entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by our contracts with the DOE. In January 2004, we and certain of our direct and indirect subsidiaries filed a lawsuit in the United States Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. We will continue to safely manage our spent fuel until it is accepted by the DOE.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2005, we had issued $37 million of guarantees to support third parties, equity method investees and employees affected by Hurricane Katrina. In addition, in 2005, we, along with two other gas and oil exploration and production companies, entered into a four-year drilling contract related to a new, ultra-deepwater drilling rig that is expected to be delivered in mid-2008. The contract has a four-year primary term, plus four one-year extension options. Our minimum commitment under the agreement, which is reflected in the lease commitments table, is for approximately $99 million over the four-year term; however, we are jointly and severally liable for up to $394 million to the contractor if the other parties fail to pay the contractor for their obligations under the primary term of the agreement, which we view as highly unlikely. We have not recognized any significant liabilities related to any of these guarantee arrangements.

We also enter into guarantee arrangements on behalf of our consolidated subsidiaries primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of our consolidated subsidiaries, that liability is included in our Consolidated Financial Statements. We are not required to recognize liabilities for guarantees issued on behalf of our subsidiaries unless it becomes probable that we will have to perform under the guarantees. No such liabilities have been recognized as of December 31, 2005. We believe it is unlikely that we would be required to perform or otherwise incur any losses associated with guarantees of our subsidiaries obligations. At December 31, 2005, we had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[1]
Subsidiary debt[2]	$ 1,268	$ 1,268
Commodity transactions[3]	3,823	1,539
Lease obligation for power generation facility[4]	898	898
Nuclear obligations[5]	355	303
Offshore drilling commitments	300	300
Other	594	413
Total	$ 7,238	$ 4,721

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of December 31, 2005 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by our subsidiaries, the value includes the recorded amount.

(2) Guarantees of $1.1 billion of debt reflected on our December 31, 2005 balance sheet related to variable interest lessor entities through which we have financed and leased several power generation projects. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

(3) Guarantees related to energy marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of CNG and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline

capacity, transportation and related commodities and services. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, we would be obligated to satisfy such obligation. We and our subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.

(4) Guarantee of a DEI subsidiary s leasing obligation for the Fairless Energy power station.

(5) Guarantees related to Virginia Power s and certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and includes guarantees for Virginia Power s commitment to buy nuclear fuel. Also, as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of the Millstone Power Station, we have also agreed to provide up to $150 million to a DEI subsidiary, if requested by such subsidiary, to pay Millstone s operating expenses.

Additionally, as of December 31, 2005 we had purchased $70 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $4.2 billion to facilitate commercial transactions by our subsidiaries with third parties.

Indemnifications

As part of commercial contract negotiations in the normal course of business, we may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. We are unable to develop an estimate of the maximum potential amount of future payments under these contracts because events that would obligate us have not yet occurred or, if any such event has occurred, we have not been notified of its occurrence. However, at December 31, 2005, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

Stranded Costs

In 1999, Virginia enacted the Virginia Restructuring Act that established a detailed plan to restructure Virginia s electric utility industry. Under the Virginia Restructuring Act, the generation portion of our Virginia jurisdictional operations is no longer

Notes to Consolidated Financial Statements, Continued

subject to cost-based regulation. The legislation s deregulation of generation was an event that required us to discontinue the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* to the Virginia jurisdictional portion of our generation operations in 1999. In 2004, amendments to the Virginia Restructuring Act and the Virginia fuel factor statute were adopted. The amendments extend capped base rates by three and one-half years, to December 31, 2010, unless modified or terminated earlier under the Virginia Restructuring Act. In addition to extending capped rates, the amendments:

- Lock in our fuel factor provisions until the earlier of July 1, 2007 or the termination of capped rates under the Virginia Restructuring Act, with no adjustment for previously incurred over-recovery or under-recovery of fuel costs, thus eliminating deferred fuel accounting for the Virginia jurisdiction;
- Provide for a one-time adjustment of our fuel factor, effective July 1, 2007 through December 31, 2010 (unless capped rates are terminated earlier under the Virginia Restructuring Act), with no adjustment for previously incurred over-recovery or under-recovery of fuel costs; and
- End wires charges on the earlier of July 1, 2007 or the termination of capped rates.

Wires charges are permitted to be collected by utilities until July 1, 2007, under the Virginia Restructuring Act. Our wires charges are set at zero in 2006 for all rate classes, and as such, Virginia customers will not pay a fee if they switch from us to a different competitive service provider.

We believe capped electric retail rates and, where applicable, wires charges provided under the Virginia Restructuring Act provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Stranded costs are those generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market.

Recovery of our potential stranded costs remains subject to numerous risks even in the capped-rate environment. These include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items. At December 31, 2005, our exposure to potential stranded costs included: long-term power purchase agreements that could ultimately be determined to be above market; generating plants that could possibly become uneconomic in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits not yet recognized in the financial statements.

Note 24. Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Fair values have been determined using available market information and valuation methodologies considered appropriate by management. The financial instruments carrying amounts and fair values are as follows:

At December 31,		**2005**		2004
		Estimated		Estimated
	Carrying	**Fair**	Carrying	Fair
(millions)	**Amount**	**Value(1)**	Amount	Value(1)
Long-term debt(2)	**$ 15,567**	**$ 15,928**	$ 15,446	$ 16,499
Junior subordinated notes payable to affiliated trusts	**1,416**	**1,537**	1,429	1,595

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

Note 25. Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction. Amounts reported as margin deposit liabilities represent funds held by us that resulted from various trading counterparties exceeding agreed-upon credit limits established by us. Amounts reported as margin deposit assets represent funds held on deposit by various trading counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. As of December 31, 2005 and 2004, we had margin deposit assets (reported in other current assets) of $160 million and $179 million, respectively, and margin deposit liabilities (reported in other current liabilities) of $133 million and $28 million, respectively.

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our December 31, 2005 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact with major companies in the energy industry and with commercial and residential energy consumers. Except for gas and oil exploration and production business activities, these transactions principally occur in the Northeast, Mid-Atlantic and Midwest regions of the United States. We do not believe that this geographic concentration contributes significantly to our overall exposure to credit risk. In addition, as a result of our large and diverse customer

Notes to Consolidated Financial Statements, Continued

base, we are not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations, including transmission services and retail energy sales.

Our exposure to credit risk is concentrated primarily within our sales of gas and oil production and energy marketing and risk management activities, including our hedging activities, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and risk management activities include trading of energy-related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. At December 31, 2005, gross credit exposure related to these transactions totaled $1.34 billion, reflecting the unrealized gains for contracts carried at fair value plus any outstanding receivables (net of payables, where netting agreements exist), prior to the application of collateral. After the application of collateral, our credit exposure is reduced to $1.20 billion. Of this amount, investment grade counterparties represent 69% and no single counterparty exceeded 10%.

Note 26. Equity Method Investments and Affiliated Transactions

At December 31, 2005 and 2004, our equity method investments totaled $331 million and $387 million, respectively, and equity earnings on these investments totaled $43 million in 2005, $34 million in 2004 and $25 million in 2003. We received dividends from these investments of $28 million, $37 million and $28 million in 2005, 2004 and 2003, respectively. Our equity method investments are reported on our Consolidated Balance Sheets in other investments. Equity earnings on these investments are reported on our Consolidated Statements of Income in other income (loss).

International Investments

CNG International (CNGI) was engaged in energy-related activities outside of the United States, primarily through equity investments in Australia and Argentina. After completing the CNG acquisition, we committed to a plan to dispose of the entire CNGI operation consistent with our strategy to focus on our core businesses.

During 2003, we recognized impairment losses totaling $84 million ($69 million after-tax) related primarily to investments in a pipeline business located in Australia and a small generation facility in Kauai, Hawaii that was sold in December 2003 for cash proceeds of $42 million. In 2004, we received cash proceeds of $52 million and recognized a benefit in other income of $27 million related to the sale of a portion of the Australian pipeline business.

At December 31, 2005, our remaining CNGI investment is accounted for at its fair value of $4 million. We continue to market this investment for sale.

Note 27. Dominion Capital, Inc.

We have substantially exited the core DCI financial services, commercial lending and residential mortgage lending businesses.

Our Consolidated Balance Sheets reflect the following DCI assets:

At December 31, (millions)	**2005**	2004
Current assets	**$ 108**	$ 26
Available-for-sale securities	**286**	335
Other investments	**89**	102
Property, plant and equipment, net	**10**	15
Deferred charges and other assets	**87**	121
Total	**$ 580**	$ 599

Securitizations of Financial Assets

At December 31, 2005 and 2004, DCI held $286 million and $335 million, respectively, of retained interests from the securitization of financial assets, which are classified as available-for-sale securities. The retained interests resulted from prior year securitizations of commercial loans receivable in collateralized loan obligation (CLO), collateralized debt obligation (CDO) and collateralized mortgage obligation (CMO) transactions.

In connection with ongoing efforts to divest our remaining financial services investments, we executed certain agreements in the fourth quarter of 2003 that resulted in the sale of commercial finance receivables, a note receivable, an undivided interest in a lease and equity investments to a new CDO structure. In exchange for the sale of these assets with an aggregate carrying amount of $123 million, we received $113 million cash and a $7 million 3% subordinated secured note in the new CDO structure and recorded an impairment charge of $3 million. The equity interests in the new CDO structure, a voting interest entity, are held by an entity that is not affiliated with us.

Simultaneous with the above transaction, the new CDO structure acquired all of the loans held by two special purpose trusts that were established in 2001 and 2000 to facilitate DCI s securitization of certain loan receivables. DCI s original transfers of the loans to the CLO trusts qualified as sales under SFAS No. 125, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. Only after receiving consents from non-affiliated third parties, the CLO trusts governing agreements were amended to permit the sale of their financial assets into the new CDO structure in 2003. In consideration for the sale of loans to the new CDO structure, the trusts received $243 million of subordinated secured 3% notes in the new CDO structure and $119 million in cash, which was used by the CLO trusts to redeem all of their outstanding senior debt securities. As of December 31, 2003, we still held residual interests in the CLO trusts, the value of which depended solely on the subordinated 3% notes issued by the new CDO. In connection with a review of the remaining assets in the CLO trusts, DCI recorded impairments totaling $23 million in 2003. We received our distribution of the new CDO notes in the first quarter of 2004 upon liquidation of the trusts.

In February 2005 the CDO structure was recapitalized to allow for additional assets. The recapitalization allows the collateral manager a twelve month ramp-up period to invest in additional eligible securities of a higher quality than previously held by the

Notes to Consolidated Financial Statements, Continued

CDO structure. The additional assets will improve the credit quality and diversity of the portfolio thereby reducing the overall risk of the portfolio.

At the closing date of the transaction in February 2005, DCI exchanged its original $258 million Class B Notes, 3% paid-in-kind (PIK) interest for $100 million Class B-1 Notes, 7.5% current pay interest and $158 million Class B-2 Notes, 3% PIK interest. DCI also has a commitment to fund up to $15 million of liquidity.

There were no mortgage securitizations in 2004 or 2005. Activity for the subordinated notes related to the new CDO structure, retained interests from securitizations of CMOs and the CLO and CDO retained interests is summarized as follows:

	Retained Interests	
(millions)	**CMO**	**CLO/CDO**
Balance at January 1, 2004	$ 141	$ 272
Liquidation of retained interest in CLO trusts		(231)
Distributions of new CDO notes to Dominion		235
Interest income		9
Amortization	(1)	
Cash received	(27)	(4)
Fair value adjustment	(46)	(13)
Balance at December 31, 2004	$ 67	$ 268
Interest income		**4**
Proceeds from the sale of CDOs		**(16)**
Other cash received	**(1)**	**(8)**
Fair value adjustment	**(28)**	
Balance at December 31, 2005	**$ 38**	**$ 248**

Key Economic Assumptions and Sensitivity Analysis

Retained interests in CLOs and CDOs are subject to credit loss and interest rate risk. Retained interests in CMOs are subject to credit loss, prepayment and interest rate risk. Given the declining residual balances and the lower weighted-average lives due to the passage of time, adverse changes of up to 20% in assumed prepayment speeds, credit losses and interest rates are estimated in each case to have less than a $3 million pre-tax impact on future results of operations.

Impairment Losses

The table below presents a summary of asset impairment losses associated with DCI operations.

Year Ended December 31, (millions)	**2005**	2004	2003
Retained interests from CMO securitizations(1)	**$ 25**	$ 46	$ 36
Retained interests from CLO/CDO securitizations(1)		13	15
2003 CDO transactions			23
Venture capital and other equity investments(2)	**10**	26	16
Deferred tax assets(3)			26
Goodwill impairment(4)			18
Total	**$ 35**	$ 85	$ 134

(1) As a result of economic conditions and historically low interest rates and the resulting impact on credit losses and prepayment speeds, we recorded impairments of our retained interests from CMO, CDO and CLO securitizations in 2005, 2004 and 2003. We updated our credit loss and prepayment assumptions to reflect our recent experience.

(2) Other impairments were recorded primarily due to asset dispositions.
(3) Represents an increase in the valuation allowance related to federal tax loss carryforwards not expected to be utilized.
(4) See Note 13 for discussion of goodwill impairments.

Note 28. Operating Segments

During the fourth quarter of 2004, we performed an evaluation of our Dominion Clearinghouse (Clearinghouse) trading and marketing operations, which resulted in a decision to exit certain energy trading activities and instead focus on the optimization of company assets. The financial impact of the Clearinghouse s optimization of company assets is now reported as part of the results of the business segments operating the related assets, in order to better reflect the performance of the underlying assets. As such, activities such as fuel management, hedging, selling the output of, contracting and optimizing the Dominion Generation assets are reported in the Dominion Generation segment. Activities related to corporate-wide enterprise commodity risk management and optimization services that are not focused on any particular business segment are reported in the Corporate segment. Aggregation of gas supply and associated gas trading and marketing activities, as well as the prior year results of certain energy trading activities exited in connection with the reorganization continue to be reported in the Dominion Energy segment.

Additionally, in January 2005 in connection with the reorganization, commodity derivative contracts held by the Clearinghouse were assessed to determine if they contribute to the optimization of our assets. As a result of this review, certain commodity derivative contracts previously designated as held for trading purposes are now held for non-trading purposes. Under our derivative income statement classification policy described in Note 2, all changes in fair value, including amounts realized upon settlement, related to the reclassified contracts were previously presented in operating revenue on a net basis. Upon reclassification as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are now reported in other operations and maintenance expense. The statement of income related amounts for those reclassified derivative sales contracts that are physically settled are now presented in operating revenue, while the statement of income related amounts for physically settled purchase contracts are reported in operating expenses.

Our company is organized primarily on the basis of products and services sold in the United States. We manage our operations through the following segments:

Dominion Delivery includes our regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations.

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and an LNG facility. It also includes certain natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage and associated gas trading and the prior year s results of certain energy trading activities exited in December 2004.

Dominion Generation includes the generation operations of our electric utility and merchant fleet as well as energy marketing and risk management activities associated with the optimization of generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. Operations are located in several major producing basins in the lower 48 states, including the outer continental shelf and deepwater areas of the Gulf of Mexico, and Western Canada.

Notes to Consolidated Financial Statements, Continued

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide enterprise commodity risk management and optimization services, the remaining assets of DCI and the net impact of our discontinued telecommunications operations that were sold in May 2004. In addition, the contribution to net income by our primary operating segments is determined based on a measure of profit that executive management believes represents the segments core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management in assessing the segment s performance or allocating resources among the segments and are instead reported in the Corporate segment. In 2005, we reported net expenses of $505 million in the Corporate segment attributable to our operating segments. The net expenses in 2005 primarily related to the impact of the following:

- A $556 million loss ($357 million after-tax) related to the discontinuance of hedge accounting in August and September 2005 for certain gas and oil hedges resulting from an interruption of gas and oil production in the Gulf of Mexico caused by Hurricanes Katrina and Rita and subsequent changes in the fair value of those hedges during the third quarter, attributable to Dominion E&P;
- A $77 million charge ($47 million after-tax) resulting from the termination of a long-term power purchase agreement, attributable to Dominion Generation; and
- A $51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation, attributable to Dominion Generation. We have not recognized any deferred tax benefits related to the charge, since realization of tax benefits is not anticipated at this time based on our expected future tax profile.

In 2004, we reported net expenses of $224 million in the Corporate segment attributable to our operating segments. The net expenses in 2004 primarily related to the impact of the following:

- A $184 million charge ($112 million after-tax) related to our interest in a long-term power tolling contract that was divested in 2005, attributable to Dominion Generation;
- A $96 million loss ($61 million after-tax) related to the discontinuance of hedge accounting in September 2004 for certain oil hedges resulting from an interruption of oil production in the Gulf of Mexico caused by Hurricane Ivan and subsequent changes in the fair value of those hedges during the third quarter, attributable to Dominion E&P; and
- A $71 million charge ($43 million after-tax) resulting from the termination of three long-term power purchase agreements, attributable to Dominion Generation.

In 2003, we reported net expenses of $220 million in the Corporate segment attributable to our operating segments. The net expenses in 2003 primarily related to the impact of the following:

- $21 million net after-tax benefit representing the cumulative effect of adopting new accounting principles, as described in Note 3 to our Consolidated Financial Statements, including:
  - SFAS No. 143: a $180 million after-tax benefit attributable to: Dominion Generation ($188 million after-tax benefit); Dominion E&P ($7 million after-tax charge); and Dominion Delivery ($1 million after-tax charge);
  - EITF 02-3: a $67 million after-tax charge attributable to Dominion Energy;
  - Statement 133 Implementation Issue No. C20: a $75 million after-tax charge attributable to Dominion Generation; and
  - FIN 46R: a $17 million after-tax charge attributable to Dominion Generation;
- $197 million ($122 million after-tax) of incremental restoration expenses associated with Hurricane Isabel, attributable primarily to Dominion Delivery;
- A $105 million charge ($65 million after-tax) for the termination of long-term power purchase agreements attributable to Dominion Generation;
- A $64 million charge ($39 million after-tax) for the restructuring and termination of certain electric sales agreements attributable to Dominion Generation; and
- $26 million of severance costs ($15 million after-tax) for workforce reductions during the first quarter of 2003, attributable to:
  - Dominion Generation ($8 million after-tax);
  - Dominion Energy ($2 million after-tax);
  - Dominion Delivery ($4 million after-tax); and
  - Dominion Exploration & Production ($1 million after-tax).

Intersegment sales and transfers are based on underlying contractual arrangements and agreements and may result in intersegment profit or loss.

Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to our operations:

Year Ended December 31, (millions)	Dominion Delivery	Dominion Energy	Dominion Generation	Dominion E&P	Corporate	Adjustments & Eliminations	Consolidated Total
2005							
Total revenue from external customers	**$ 4,298**	**$ 1,673**	**$ 8,068**	**$ 2,644**	**$ 29**	**$ 1,329**	**$ 18,041**
Intersegment revenue	**39**	**1,407**	**203**	**246**	**588**	**(2,483)**	
Total operating revenue	**4,337**	**3,080**	**8,271**	**2,890**	**617**	**(1,154)**	**18,041**
Depreciation, depletion and amortization	**329**	**121**	**366**	**563**	**35**	**(2)**	**1,412**
Equity in earnings of equity method investees	**1**	**13**	**21**	**3**	**5**		**43**
Interest income	**11**	**12**	**61**	**15**	**247**	**(251)**	**95**
Interest and related charges	**191**	**84**	**289**	**140**	**538**	**(251)**	**991**
Income tax expense (benefit)	**253**	**212**	**218**	**324**	**(425)**		**582**
Income from discontinued operations, net of tax					**5**		**5**
Cumulative effect of change in accounting principle, net of tax					**(6)**		**(6)**
Net income (loss)	**448**	**319**	**402**	**565**	**(701)**		**1,033**
Investment in equity method investees	**5**	**97**	**112**	**42**	**75**		**331**
Capital expenditures	**532**	**399**	**724**	**1,690**	**13**		**3,358**
Total assets (billions)	**10.4**	**6.6**	**17.6**	**15.4**	**16.0**	**(13.3)**	**52.7**
2004							
Total revenue from external customers	$ 3,757	$ 2,047	$ 4,925	$ 2,291	$ 69	$ 902	$ 13,991
Intersegment revenue	77	384	793	157	509	(1,920)	
Total operating revenue	3,834	2,431	5,718	2,448	578	(1,018)	13,991
Depreciation, depletion and amortization	316	116	282	558	35	(2)	1,305
Equity in earnings of equity method investees	1	12	11	(1)	11		34
Interest income	8	14	52	2	269	(244)	101
Interest and related charges	151	62	254	94	622	(244)	939
Income tax expense (benefit)	256	119	321	314	(310)		700
Loss from discontinued operations, net of tax					(15)		(15)
Net income (loss)	466	190	525	595	(527)		1,249
Investment in equity method investees	5	94	162	40	86		387
Capital expenditures	441	354	623	1,311	21		2,750
Total assets (billions)	9.2	7.2	14.5	11.3	14.3	(11.1)	45.4
2003							
Total revenue from external customers	$ 3,287	$ 1,863	$ 4,482	$ 1,858	$ 149	$ 456	$ 12,095
Intersegment revenue	61	493	293	150	591	(1,588)	
Total operating revenue	3,348	2,356	4,775	2,008	740	(1,132)	12,095
Depreciation, depletion and amortization	302	104	229	532	49		1,216
Equity in earnings of equity method investees		12	13	6	(6)		25
Interest income	14	8	52	1	271	(237)	109
Interest and related charges	171	64	239	82	656	(237)	975
Income tax expense (benefit)	236	223	312	220	(394)		597
Loss from discontinued operations, net of tax					(642)		(642)
Cumulative effect of changes in accounting principles, net of tax					11		11
Net income (loss)	453	346	512	415	(1,408)		318

As of December 31, 2005 and 2004, approximately 2% of our total long-lived assets were associated with international operations. For the years ended December 31, 2005, 2004 and 2003, approximately 1%, 2% and 2%, respectively, of operating revenues were associated with international operations.

Notes to Consolidated Financial Statements, Continued

Note 29. Gas and Oil Producing Activities (unaudited)

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization follow:

At December 31,	**2005**	2004
(millions)		
Capitalized costs:		
Proved properties	**$ 9,929**	$ 8,246
Unproved properties	**1,775**	1,623
	11,704	9,869
Accumulated depletion:		
Proved properties	**2,513**	1,921
Unproved properties	**109**	109
	2,622	2,030
Net capitalized costs	**$ 9,082**	$ 7,839

Total Costs Incurred

The following costs were incurred in gas and oil producing activities:

Year Ended December 31,		**2005**			2004			2003	
	Total	**United States**	**Canada**	Total	United States	Canada	Total	United States	Canada
(millions)									
Property acquisition costs:									
Proved properties	**$ 118**	**$ 118**		$ 20	$ 20		$ 181	$ 181	
Unproved properties	**151**	**137**	**$ 14**	116	102	$ 14	133	125	$ 8
	269	**255**	**14**	136	122	14	314	306	8
Exploration costs	**235**	**230**	**5**	213	199	14	291	266	25
Development costs(1)	**1,207**	**1,128**	**79**	915	841	74	667	604	63
Total	**$ 1,711**	**$ 1,613**	**$ 98**	$ 1,264	$ 1,162	$ 102	$ 1,272	$ 1,176	$ 96

(1) Development costs incurred for proved undeveloped reserves were $284 million, $172 million and $182 million for 2005, 2004 and 2003, respectively.

Results of Operations

We caution that the following standardized disclosures required by the FASB do not represent our results of operations based on our historical financial statements. In addition to requiring different determinations of revenue and costs, the disclosures exclude the impact of interest expense and corporate overhead.

Year Ended December 31,		**2005**			2004			2003	
	Total	**United States**	**Canada**	Total	United States	Canada	Total	United States	Canada
(millions)									
Revenue (net of royalties) from:									

Sales to nonaffiliated companies	**$ 1,499**	**$ 1,369**	**$ 130**	$ 1,526	$ 1,297	$ 229	$ 1,736	$ 1,552	$ 184
Transfers to other operations	**268**	**268**		195	195		185	185	
Total	**1,767**	**1,637**	**130**	1,721	1,492	229	1,921	1,737	184
Less:									
Production (lifting) costs	**443**	**406**	**37**	394	309	85	357	294	63
Depreciation, depletion and amortization	**564**	**525**	**39**	560	497	63	526	470	56
Income tax expense	**283**	**264**	**19**	295	266	29	356	350	6
Results of operations	**$ 477**	**$ 442**	**$ 35**	$ 472	$ 420	$ 52	$ 682	$ 623	$ 59

40

Notes to Consolidated Financial Statements, Continued

Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the United States and Canada at December 31, 2005, 2004 and 2003, and changes in the reserves during those years, are shown in the two schedules that follow:

	2005			2004			2003		
	Total	**United States**	**Canada**	Total	United States	Canada	Total	United States	Canada
(billion cubic feet)									
Proved developed and undeveloped reserves Gas									
At January 1	**4,910**	**4,814**	**96**	5,161	4,718	443	4,885	4,387	498
Changes in reserves:									
Extensions, discoveries and other additions	**299**	**276**	**23**	387	342	45	810	767	43
Revisions of previous estimates(1)	**73**	**71**	**2**	2	141	(139)	(152)	(94)	(58)
Production	**(290)**	**(275)**	**(15)**	(348)	(312)	(36)	(375)	(335)	(40)
Purchases of gas in place	**55**	**55**		10	10		133	133	
Sales of gas in place	**(85)**	**(85)**		(302)	(85)	(217)	(140)	(140)	
At December 31	**4,962**	**4,856**	**106**	4,910	4,814	96	5,161	4,718	443
Proved developed reserves Gas									
At January 1	**3,685**	**3,591**	**94**	3,834	3,474	360	3,865	3,479	386
At December 31	**3,706**	**3,605**	**101**	3,685	3,591	94	3,834	3,474	360
Proved developed and undeveloped reserves Oil									
(thousands of barrels)									
At January 1	**164,062**	**144,007**	**20,055**	204,509	149,707	54,802	204,650	150,577	54,073
Changes in reserves:									
Extensions, discoveries and other additions	**6,681**	**5,399**	**1,282**	11,615	7,699	3,916	15,114	7,887	7,227
Revisions of previous estimates(2)	**63,884**	**65,264**	**(1,380)**	(22,925)	(1,989)	(20,936)	1,489	5,348	(3,859)
Production	**(15,575)**	**(14,714)**	**(861)**	(13,783)	(11,258)	(2,525)	(12,251)	(9,612)	(2,639)
Purchases of oil in place	**69**	**69**		666	666		380	380	
Sales of oil in place	**(1,423)**	**(1,423)**		(16,020)	(818)	(15,202)	(4,873)	(4,873)	
At December 31	**217,698**	**198,602**	**19,096**	164,062	144,007	20,055	204,509	149,707	54,802
Proved developed reserves Oil									
At January 1	**113,992**	**102,152**	**11,840**	88,379	55,530	32,849	94,205	59,484	34,721
At December 31	**152,889**	**145,735**	**7,154**	113,992	102,152	11,840	88,379	55,530	32,849

(1) Approximately 135 bcf of the 2004 Canadian reserve revisions pertained to properties sold in 2004 and resulted from performance-based reserve reclassifications from proved undeveloped to unproved.

(2) The 2005 U.S. revision is primarily due to an increase in plant liquids that resulted from a contractual change for a portion of our gas processed by third parties. We now take title to and market the natural gas liquids extracted from this gas. Approximately 17 million barrels of the 2004 Canadian reserve revisions pertained to properties sold in 2004 and resulted from performance-based reserve re-determinations on two British Columbia enhanced oil recovery projects.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following tabulation has been prepared in accordance with the FASB s rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities that we own:

2005			2004			2003		
Total	**United States**	**Canada**	Total	United States	Canada	Total	United States	Canada

(millions)									
Future cash inflows(1)	**$ 63,004**	**$ 61,112**	**$ 1,892**	$ 36,819	$ 35,735	$ 1,084	$ 36,486	$ 32,922	$ 3,564
Less:									
Future development costs(2)	**1,979**	**1,877**	**102**	1,527	1,488	39	1,505	1,391	114
Future production costs	**8,127**	**7,718**	**409**	5,609	5,302	307	5,582	4,765	817
Future income tax expense	**19,019**	**18,527**	**492**	10,152	9,909	243	9,457	8,715	742
Future cash flows	**33,879**	**32,990**	**889**	19,531	19,036	495	19,942	18,051	1,891
Less annual discount (10% a year)	**18,916**	**18,560**	**356**	10,505	10,275	230	10,709	9,745	964
Standardized measure of discounted future net cash flows	**$ 14,963**	**$ 14,430**	**$ 533**	$ 9,026	$ 8,761	$ 265	$ 9,233	$ 8,306	$ 927

(1) Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year-end.

(2) Estimated future development costs, excluding abandonment, for proved undeveloped reserves are estimated to be $594 million, $330 million and $176 million for 2006, 2007 and 2008, respectively.

41

Notes to Consolidated Financial Statements, Continued

In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pretax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB s standardized measure of discounted future net cash flows represent the fair market value of our proved reserves. We caution that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year:

(millions)	**2005**	2004	2003
Standardized measure of discounted future net cash flows at January 1	**$ 9,026**	$ 9,233	$ 7,805
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	**(2,502)**	(2,004)	(1,997)
Prices and production and development costs related to future production	**8,929**	1,656	480
Extensions, discoveries and other additions, less production and development costs	**1,396**	1,118	1,920
Previously estimated development costs incurred during the year	**284**	172	182
Revisions of previous quantity estimates	**27**	(734)	(918)
Accretion of discount	**1,367**	1,359	1,149
Income taxes	**(3,659)**	(291)	(679)
Other purchases and sales of proved reserves in place	**140**	(878)	84
Other (principally timing of production)	**(45)**	(605)	1,207
Standardized measure of discounted future net cash flows at December 31	**$ 14,963**	$ 9,026	$ 9,233

42

Notes to Consolidated Financial Statements, Continued

Note 30. Quarterly Financial and Common Stock Data (unaudited)

A summary of our quarterly results of operations for the years ended December 31, 2005 and 2004 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
2005					
Operating revenue	**$ 4,736**	**$ 3,646**	**$ 4,564**	**$ 5,095**	**$ 18,041**
Income from operations	**873**	**705**	**185**	**676**	**2,439**
Income from continuing operations before cumulative effect of change in accounting principle	**429**	**332**	**10**	**263**	**1,034**
Net income	**429**	**332**	**15**	**257**	**1,033**
Basic EPS:					
Income from continuing operations before cumulative effect of change in accounting principle	**1.26**	**0.98**	**0.03**	**0.76**	**3.02**
Net income	**1.26**	**0.98**	**0.04**	**0.74**	**3.02**
Diluted EPS:					
Income from continuing operations before cumulative effect of change in accounting principle	**1.25**	**0.97**	**0.03**	**0.76**	**3.00**
Net income	**1.25**	**0.97**	**0.04**	**0.74**	**3.00**
Dividends paid per share	**0.67**	**0.67**	**0.67**	**0.67**	**2.68**
Common stock prices (high-low)	**$ 76.01-66.51**	**$ 76.87-67.75**	**$ 86.87-72.15**	**$ 86.97-73.50**	**$ 86.97-66.51**
2004					
Operating revenue	$ 3,884	$ 3,045	$ 3,296	$ 3,766	$ 13,991
Income from operations	893	586	755	502	2,736
Income from continuing operations	445	258	337	224	1,264
Net income	437	251	337	224	1,249
Basic EPS:					
Income from continuing operations	1.37	0.79	1.02	0.67	3.84
Net income	1.35	0.76	1.02	0.67	3.80
Diluted EPS:					
Income from continuing operations	1.36	0.79	1.02	0.67	3.82
Net income	1.34	0.76	1.02	0.67	3.78
Dividends paid per share	0.645	0.645	0.645	0.665	2.60
Common stock prices (high-low)	$ 65.85-61.20	$ 64.75-60.78	$ 65.87-62.07	$ 68.85-62.97	$ 68.85-60.78

Our 2005 results include the impact of the following significant items:

- First quarter results include a $47 million after-tax charge resulting from the termination of a long-term power purchase agreement, $31 million of after-tax losses related to the discontinuance of hedge accounting for certain oil hedges, resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges and a $28 million after-tax benefit due to the recognition of business interruption insurance revenue associated with the recovery of delayed gas and oil production due to Hurricane Ivan.
- Second quarter results include an $86 million after-tax benefit due to the final settlement of business interruption insurance claims associated with Hurricane Ivan.
- Third quarter results include a $357 million after-tax loss related to the discontinuance of hedge accounting for certain gas and oil hedges, resulting from an interruption of gas and oil production in the Gulf of Mexico caused by Hurricanes Katrina and Rita, and subsequent changes in the fair value of those hedges.
-

Fourth quarter results include a $51 million after-tax charge to establish an allowance related to credit exposure associated with the bankruptcy of Calpine Corporation and a $77 million after-tax benefit reflecting the impact of a decrease in gas and oil prices on hedges that were de-designated following Hurricanes Katrina and Rita.

Our 2004 results include the impact of the following significant items:

- Third quarter results include a $61 million after-tax loss related to the discontinuance of hedge accounting for certain oil hedges, resulting from an interruption of oil production in the Gulf of Mexico caused by Hurricane Ivan, and subsequent changes in the fair value of those hedges.
- Fourth quarter results include a $112 million after-tax charge related to the sale of our interest in a long-term power tolling contract that was divested in 2005, a $64 million after-tax charge resulting from the termination of two long-term power purchase agreements, and a $61 million after-tax benefit due to the recognition of business interruption insurance revenue associated with delayed gas and oil production due to Hurricane Ivan.

43

Notes to Consolidated Financial Statements, Continued

Note 31. Subsequent Event

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, The Peoples Natural Gas Company and Hope Gas, Inc, for $969.6 million plus adjustments to reflect capital expenditures and changes in working capital. The transaction is expected to close by the first quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia as well as approval under the federal Hart-Scott-Rodino Act. The carrying amounts of the major classes of assets and liabilities to be disposed of are as follows:

At December 31,	**2005**	2004
(millions)		
Assets		
Current assets	**$ 438**	$ 291
Property, plant and equipment, net	**694**	662
Deferred charges and other assets	**107**	89
Total assets	**$ 1,239**	$ 1,042
Liabilities		
Current liabilities	**$ 323**	$ 200
Deferred credits and other liabilities	**209**	194
Total liabilities	**$ 532**	$ 394

Item 15. Exhibits and Financial Statement Schedules

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

45

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.

DOMINION RESOURCES, INC.

By: /s/ Steven A. Rogers

(Steven A. Rogers, Vice President, Controller and Principal Accounting Officer)

Date: March 6, 2006

46