

ANNUAL
REPORT

'06



Dominion®
It all starts here.®

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In business, an old saying goes, the only constant is change. This year's report to shareholders explains how and why your company is making changes in its business plan to deliver the highest value to shareholders in changing markets.

Longtime shareholders know that, at Dominion, we have a successful history of tailoring business planning to market conditions. We will continue to work to stay abreast of and ahead of market trends. Flexibility is part of our character.

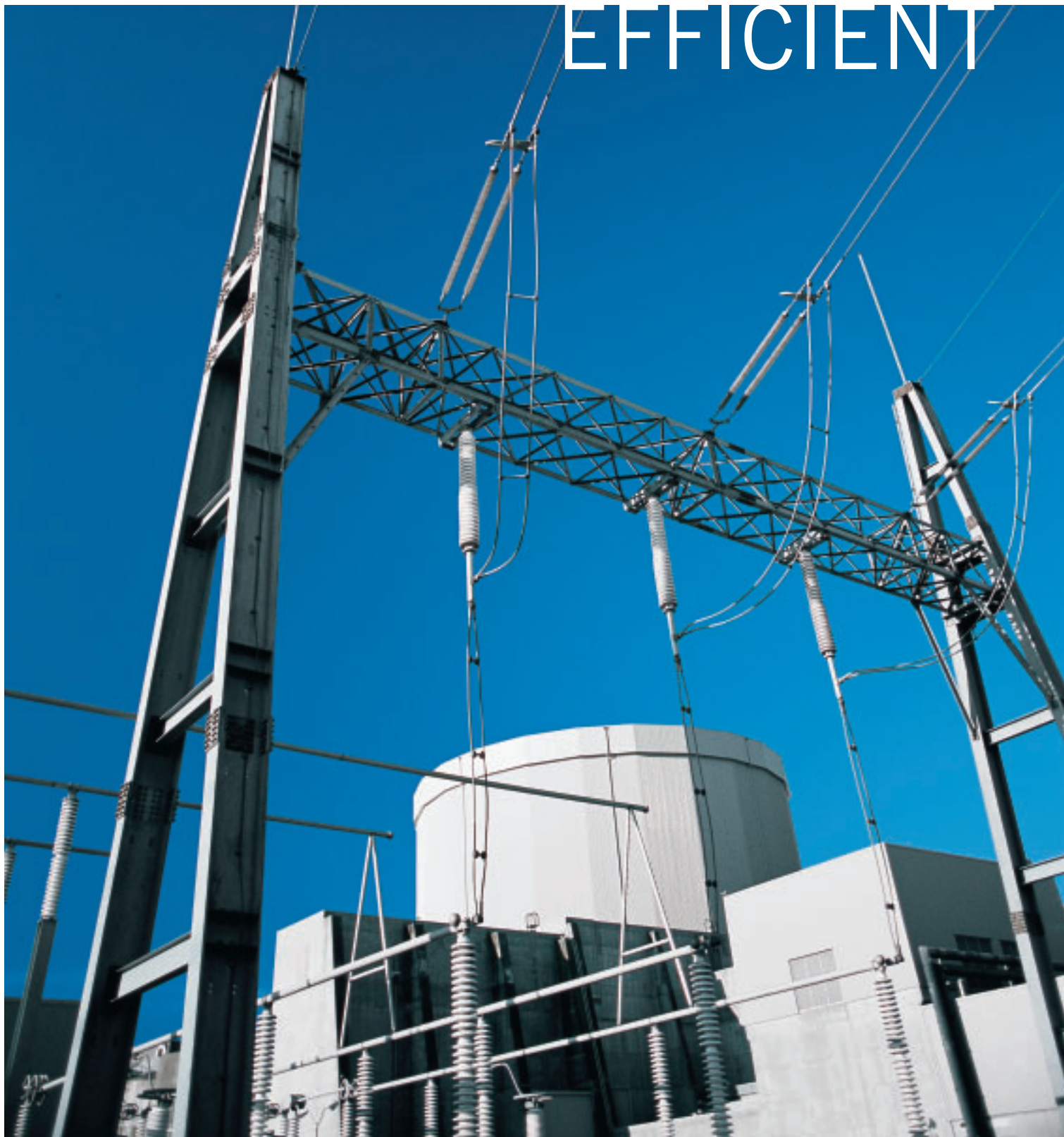
Some things don't change, however: Our core values of safety, ethics, excellence and teamwork as One Dominion. Nowhere do these enduring values manifest themselves more transparently than in our efficient and reliable operations in the growing economies we serve, our enthusiasm to give back to our communities and, as an energy company, the way we treat our environment.

Efficiency. It is embedded in our value system. It is a key factor behind our continued success as one of the nation's largest integrated energy companies. Dominion produces, transmits, stores and distributes electric power and natural gas through one of the nation's most efficient networks of energy assets.

Getting optimal value from these core assets and doing it safely at industry-leading standards of excellence has set Dominion apart for years. We like the distinction. We intend to build on the record.

At Dominion, we demonstrate our commitment to efficient operations in various ways: through focused safety practices and the resulting top-notch safety records;

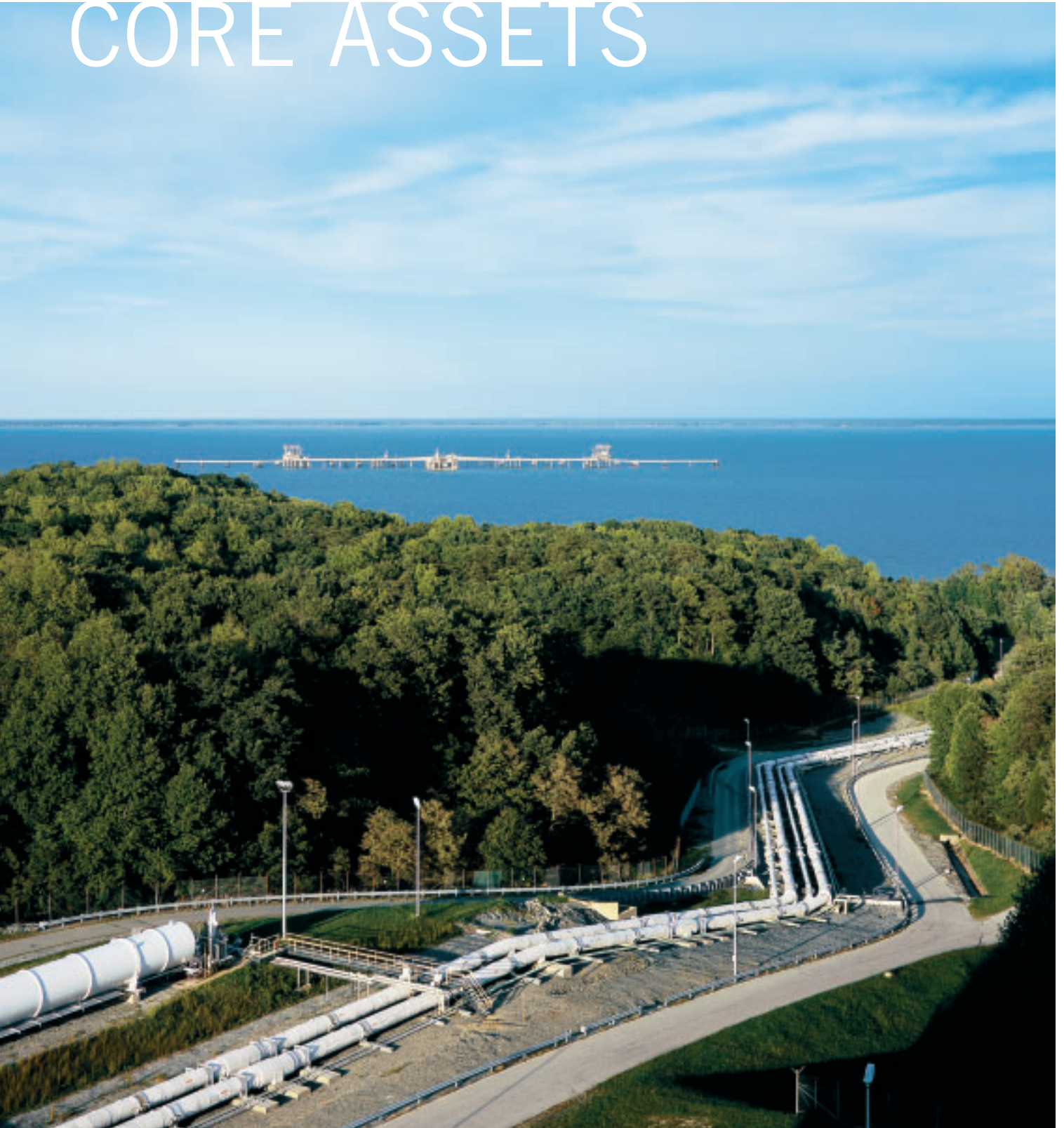
EFFICIENT



through analytical business processes that produce bottom-line savings across the company; through wise and prudent use of your investment capital; and through effective teamwork that unites us behind a common goal: serving you, our owners.

Opposite Page: Millstone Power Station's Unit 3 surpassed one year in continuous operation in 2006, when it reached its 393rd consecutive day on line. **Below:** Since its reactivation in 2003, Dominion's Cove Point facility has been the most active LNG terminal in the nation.

CORE ASSETS



VIBRANT ECONOMIC



ENVIRONMENT



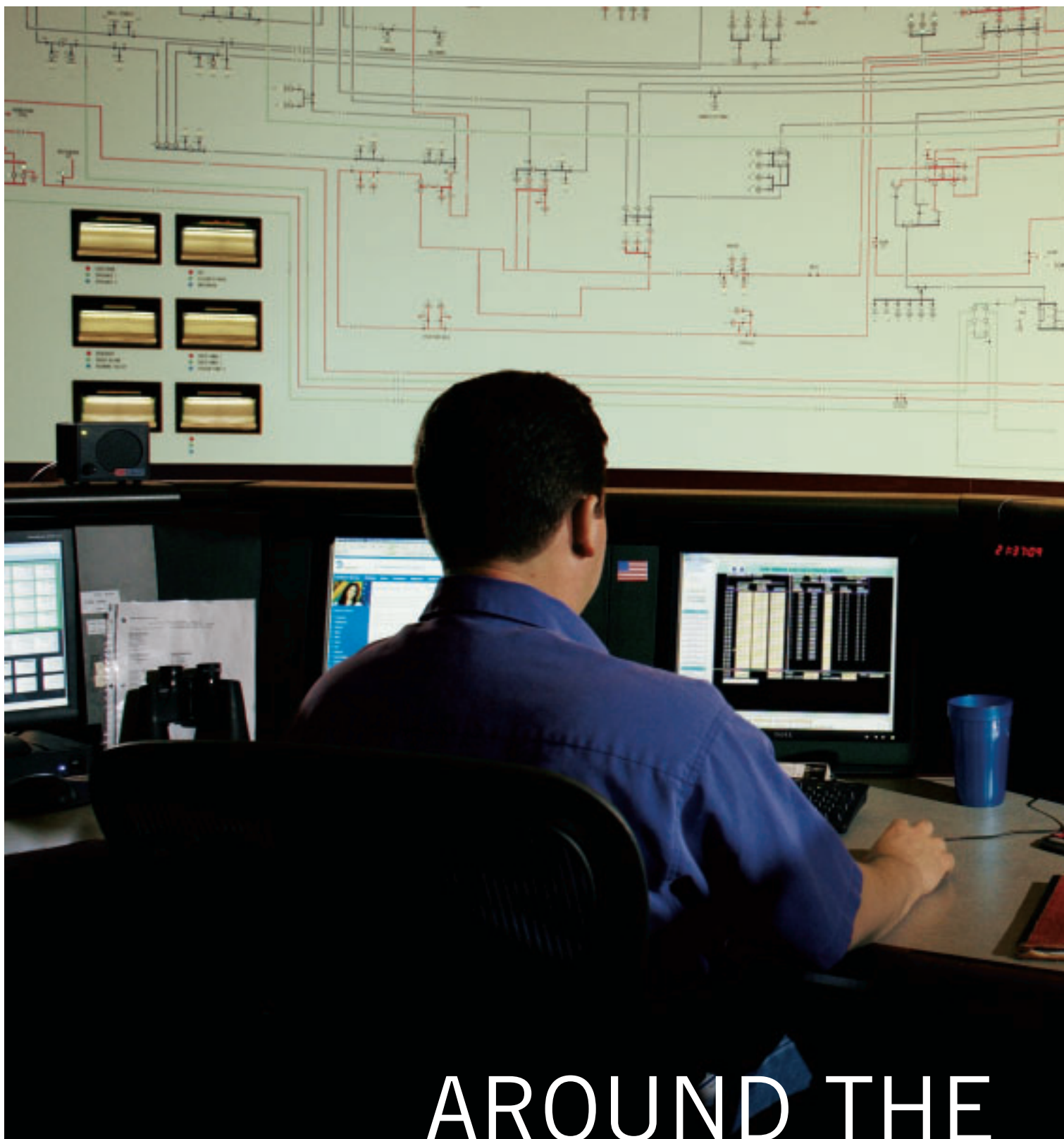
One of the first questions that an investor should consider is this: What evidence exists that a company's products and services are in demand and will be in even more demand in the future?

Dominion's businesses operate in and serve the nation's vibrant mid-Atlantic, Northeast and Midwest regions—from the fast-growth Washington suburbs of Northern Virginia, to power-hungry New England, to natural gas users in the Northeast interior in need of more supply. Our growth in customers continues unabated.

The demand for energy and energy services is strong and growing. We are rising to the challenge by working hard to serve existing and new customers and by building new facilities to create efficient and low-cost ways to serve them better.

And to do it reliably.

Opposite Page: Among customers we are proud to serve is The National Air and Space Museum's impressive Steven F. Udvar-Hazy Center in Chantilly, Va. Its innovative computer technology enables it to monitor energy use in real time. **Above:** A typical Dominion customer had power 99.98 percent of the time in 2006, excluding major storms.

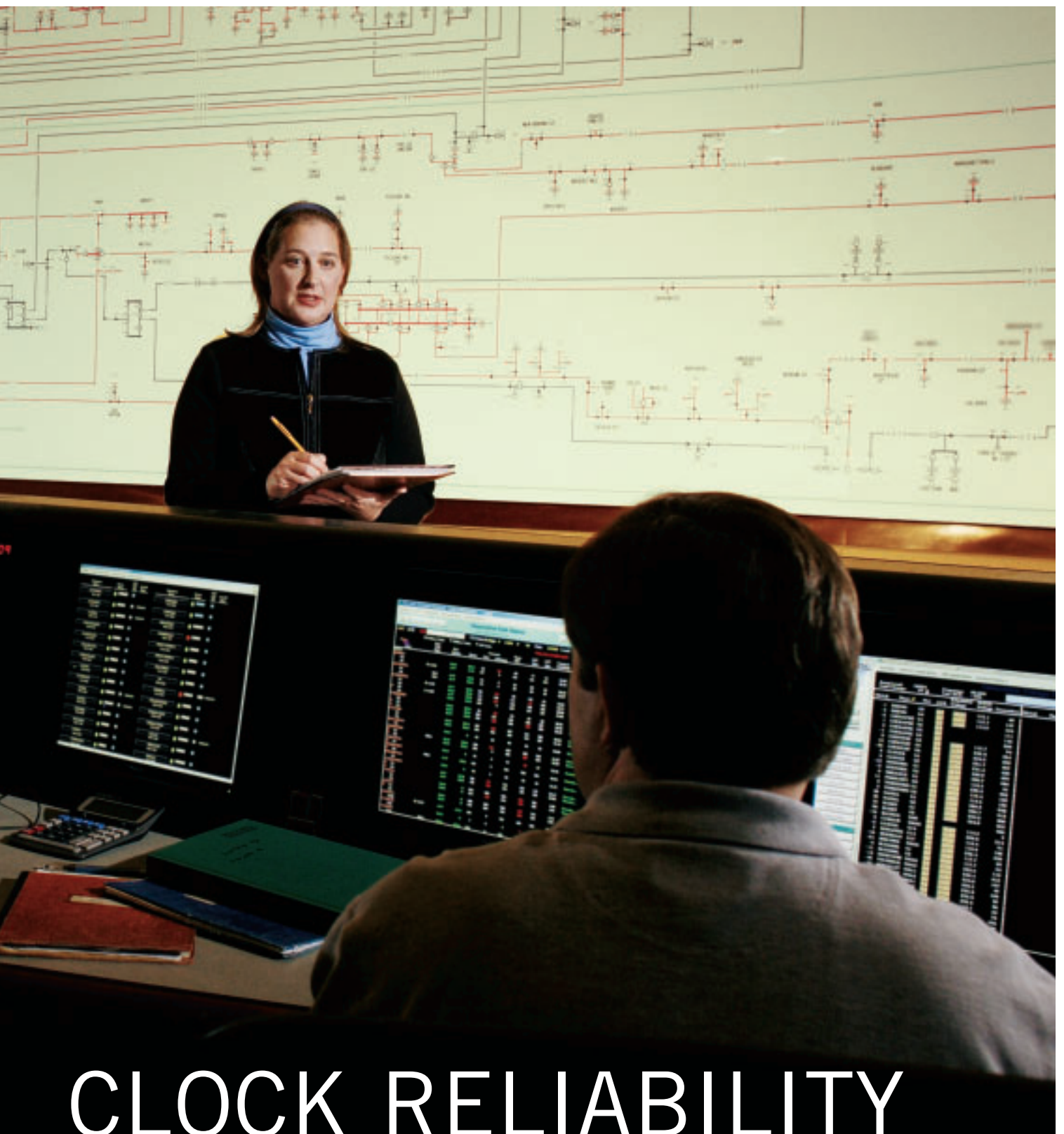


AROUND THE

Above: Night shift at Dominion's electric System Operations Center, where our state-of-the-art systems and practices in analysis and training were company standards before they became industry requirements.

Dominion has a track record of excellent operations that promote vibrant economic growth through multiple businesses and assets.

Rooted in a longstanding tradition of public service, Dominion's regulated businesses take pride in providing



CLOCK RELIABILITY

energy reliably—around the clock, rain or shine, winter storm or summer heat wave.

Keeping the lights on, businesses running and homes comfortable is a big part of the Dominion culture. It motivates us to achieve the excellence that our customers demand and expect. This company mindset has formed

over decades of public service stretching back to the early part of the 20th Century.

Many of our employees are dedicated to improving the quality of life in the communities in which they live and work. Dominion volunteers have more than two decades and thousands of service projects to their credit.

Many of our customers know us as the local utility whose employees build homes for Habitat for Humanity, refurbish playgrounds at neighborhood schools, or deliver

meals to elderly shut-ins who look forward to their visits as much as they do the food.

From Texas to the Great Lakes to the Outer Banks, our volunteers help the company do well by simply doing good in the community. They are the public face of Dominion. The children they tutor, the canned goods they sort, the lives they touch—these are the things people see and remember about us. The spirit, initiative and

GIVING TO OUR



enthusiasm of Dominion's volunteers have created one of America's premier corporate volunteer programs. They are the best resource we have for meeting our social responsibilities in the cities, towns and rural areas in which we do business.

Opposite Page: Northern Virginia employees gather toys year-round for sick children and their siblings in several area hospitals on behalf of Col's Closet, a nonprofit honoring the passing of the young son of a Dominion lineman. **Below:** For 24 years, Dominion's EnergyShare program has provided fuel assistance to people who can't afford to warm their homes. In early 2007, we contributed \$1 million to the program.





All of this we do mindfully, aware of our environmental stewardship responsibilities.

People are breathing easier in Virginia and North Carolina, the states where Dominion operates its electric power utility business. Perhaps you saw or heard how we are working to keep the environment clean on feature segments carried by "CBS Sunday Morning" and National Public Radio.

Instead of battling federal regulators in court, Dominion chose to work with them to develop environmental programs that improve air quality.

In fact, Dominion's environmental commitment goes well beyond our electric power service area. Across our utility fleet serving Virginia and North Carolina and across our merchant fleet serving the Midwest and Northeast, we are spending \$3.4 billion to reduce emissions at our coal-powered units.



ENVIRONMENTAL ROLE

In Virginia alone, Dominion expects to have made major reductions by 2015, cutting sulfur dioxide emissions on average by 80 percent at its coal stations. Nitrogen oxide emissions are targeted to drop by 70 percent and mercury emissions are targeted to decline by 86 percent from levels in 2000.

Opposite Page: *Biologist Rick Willis collects a groundwater sample from a monitoring well at Chesterfield Power Station. Protection of groundwater resources is a high priority for Dominion. Above:* We manage our environmental programs mindful of our responsibility to future generations.

The surest way to build on past success is to act as your own devil's advocate. Test assumptions. Ask hard questions. Look at the broader picture and consider alternatives, even when things are working well. We do.

Longtime investors in Dominion know that our exploration and production (E&P) unit has played an important role in the profitability of the company's integrated mix of natural gas and electric power businesses.

By the end of 2006, thanks to reserve growth, increasing production and rising energy prices, our natural gas and oil E&P unit contributed 34 percent of Dominion's primary operating segment earnings, or \$680 million.

POTENTIAL E&P SALE YIELDS COMPELLING INVESTOR BENEFIT

This scale gave us an opportunity to re-evaluate our strategic direction. During 2006, we assessed the wisdom of selling the E&P business to refocus on our regulated

EACH OF OUR SUPERBLY OPERATED REMAINING BUSINESSES WILL HAVE ITS OWN UNIQUE PROSPECTS FOR EARNINGS GROWTH.

and other unregulated businesses. Our E&P leaders and their team have done a superior job in growing both their assets and earnings. After a lengthy and thorough analysis, however, we announced in November a decision to pursue the sale of almost all of our E&P assets. We would keep our Appalachian properties, which would represent less than 5 percent of our post-sale consolidated earnings.

The determination to pursue a sale of about one-third of our company during my first year as CEO was not an easy one. If completed, the sale would represent the most significant change in our business strategy since our successful merger with Consolidated Natural Gas in 2000.

Why do it? The answer lies in Dominion's basic business philosophy: a commitment to managing for the long-term rather than the short, in the belief that higher earnings based on higher risks is not the best way to create the stable, long-term investment profile preferred by investors like Dominion's shareholders.

For investors, the benefits of this risk-reducing step would include:

- More stable earnings growth that is less dependent on volatile oil and natural gas markets and deserving of higher valuation multiples enjoyed by our peer companies.



Thomas F. Farrell II President and Chief Executive Officer

THE SUREST WAY TO BUILD ON PAST SUCCESS IS TO ACT AS YOUR OWN DEVIL'S ADVOCATE. TEST ASSUMPTIONS. ASK HARD QUESTIONS. LOOK AT THE BROADER PICTURE AND CONSIDER ALTERNATIVES, EVEN WHEN THINGS ARE WORKING WELL. WE DO.

- Increased focus on cash flow from our utility operations and the opportunity to invest in both new capacity to benefit from evolving wholesale electric markets and in urgently needed natural gas and electric infrastructure projects.
- Potential to return capital to investors in the form of increased dividends and share repurchases.

TRADITIONAL REMAINING BUSINESSES

EXPECT EARNINGS GROWTH

Each of our superbly operated remaining businesses will have its own unique prospects for earnings growth. Because we are refocusing the company, we have structured this year's annual report to shareholders to highlight these businesses, their growth prospects in the energy-intensive U.S. economy, and their expected contributions to future consolidated operating earnings. Looking ahead, we would expect Dominion's long-term operating earnings to grow between 4 percent and 6 percent.

I will keep you updated on our progress throughout the year. We expect any sale of our E&P assets to be

completed by mid-2007. Following such a sale, and other sales I will describe later, we would own and operate:

- One of the most rapidly expanding electric distribution franchises in the nation, Dominion Virginia Power, which now serves more than 2.3 million homes and businesses, as well as a premier natural gas distribution company, Dominion East Ohio, which serves more than 1.2 million customer accounts in Ohio.
- More than 26,300 megawatts of electric generation that provides energy not only to Dominion Virginia Power customers but also to much of New England and parts of the Midwest and mid-Atlantic regions.
- The nation's largest natural gas storage system as well as a major transmission pipeline network strategically located within major gas-consuming markets. Our work to physically inspect and maintain these critical fuel transportation arteries at the highest standards has created a network of unparalleled integrity.
- A smaller but geographically advantaged and low-risk natural gas and oil production operation.
- A growing competitive retail business that provides energy and energy services to more than 1.5 million customer accounts in states where competitive markets have developed.

MORE THAN EARNINGS, SHARE PRICE:**INCREASED EMPHASIS ON RETURN ON INVESTED CAPITAL (ROIC) AND DIVIDEND GROWTH**

If we complete a sale of the E&P business, we would use the proceeds to reduce debt and maintain or improve our existing credit ratings. These actions would boost earnings by reducing borrowing costs. We also expect to repurchase shares and/or acquire select assets that would strengthen our remaining businesses.

Increasing your dividend is another post-sale goal. We believe that we could pay out a higher percentage of our earnings in dividends from the remaining businesses because of their more stable nature. Our directors will address the issue of a possible change in dividend policy following any sale.

In early 2007, the board followed through on an earlier commitment to grow your dividend. It announced that it expected to increase your annual dividend rate to \$2.84 per share in 2007, up 8 cents a share over your annual dividend rate of \$2.76 in 2006, or 3 percent. In 2006, the board also adopted an 8-cent increase in your annual dividend rate, an increase of about 3 percent over 2005.

Our shares closed the year at \$83.84 per share, up about 9 percent from \$77.20 at the end of 2005. This share price appreciation and dividend produced a total shareholder return in excess of 12 percent. In some years, that might have been acceptable, but we recognize that it paled next to the performance of our peer group and the stock market as a whole.

Investors who have owned Dominion shares for a number of years know that management operates the company for them, the long-term shareholder. We do not manage and assess results through the snapshots of any given quarter or selected 12-month calendar year. But our share valuation in 2006 illustrates that traditional utility investors discounted our strong group of largely regulated operating businesses because they were

paired with a higher-profit, higher-risk E&P business of considerable size.

As a result, Dominion's total return in 2006 trailed those of the Standard & Poor's 500 Electric Utilities Index and the S&P 500 Gas Utilities Index, which produced total returns of more than 23 percent and more than 26 percent, respectively. Beyond our sector, the S&P 500 delivered a total return of more than 15 percent, while the Dow Jones Industrial Average returned more than 19 percent.

2006 GAAP EARNINGS INCREASE

Yet, Dominion ended 2006 by making \$3.93 per share under Generally Accepted Accounting Principles (GAAP), up 31 percent from GAAP earnings of \$3.00 per share in 2005. Excluding certain items, we produced operating earnings in 2006 of \$5.16 per share, up over 13 percent from operating earnings of \$4.56 per share a year earlier, largely due to the underlying strengths of our businesses. Turn to page 28 for a reconciliation of our operating earnings to GAAP earnings. Visit www.dom.com to view a copy of our full 2006 earnings release.

In 2006, our operating earnings were in line with expectations of \$5.05 to \$5.25 per share.

OTHER ASSET SALES ENABLE DEBT REDUCTION

As a result of our increased focus on return on invested capital, we reached an agreement in 2006 to sell our two smallest natural gas distribution utilities in Pennsylvania and West Virginia to Pittsburgh-based Equitable Resources. Together, Dominion Peoples and Dominion Hope serve less than 12 percent of our 4 million-plus utility customer base. The two utilities are run by talented, skilled and energetic workers. Still, we concluded their value would best be realized if they were owned by another company.

Pending regulatory approval, we expect to close the sale of both businesses by mid-2007 for pre-tax proceeds

of about \$970 million, before adjustments for capital expenditures and changes in working capital. We will use the after-tax proceeds to reduce debt.

Late last year we also reached an agreement to sell three natural gas-fired peaking units in Pennsylvania, West Virginia and Ohio. That transaction is expected to close in the first quarter of 2007, and the proceeds also will be used to reduce debt.

Reducing debt to maintain and possibly improve our credit ratings is essential to our long-term success. Thanks to several factors, our credit metrics improved materially during 2006. Our solid financial performance helped, as did changes in the market value of our hedge portfolio, the receipt of \$330 million in proceeds from the conversion of equity-linked debt securities and the issuance of about \$95 million of new equity to satisfy demand for direct investment in our stock. In addition, in 2006 we issued two hybrid securities totaling \$800 million that received significant equity treatment by Fitch, Moody's and Standard & Poor's credit rating agencies.

We have made excellent progress since we set out in early 2006 to strengthen our balance sheet and stabilize our ratings. At year-end, our company's adjusted debt as a percentage of capital stood at about 54.5 percent, compared with 58.1 percent in 2005. A chart showing our debt ratios under GAAP appears on page 28. At year-end, Fitch rated our bonds at BBB+, Moody's at Baa2, and S&P at BBB. Given the strength of our financial plan, we expect to demonstrate continued improvements.

SAFETY, ETHICS, EXCELLENCE AND ONE DOMINION

When I assumed the position of CEO more than one year ago, I told our employees, investors and customers that our core values of safety, ethics and excellence were the right mind-set for a company that produces energy from a platform of businesses largely regulated at the federal and state levels.

I also stressed the importance of teamwork under a guiding principle that I call "One Dominion." Everything else will fall into place, I said, if we adhere to the One Dominion standard. One year into this challenge, I have seen overwhelming evidence to support my belief. If we do our jobs safely, adhere strictly to all laws and regulations, and execute strongly as one team, we will reward investors seeking a solid core utility holding.

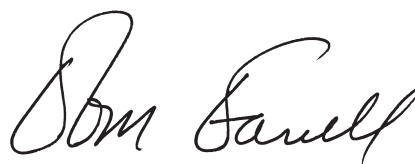
Employees across all of our businesses have served customers, vendors, regulators and the communities where we live and work with spirit and dedication. They turned in another excellent year in operations. They had a great safety year. And they turned in high-quality work in the areas of financial performance that we can control. As someone from a family with strong military ties, I recognize that our employees imposed upon themselves a strict discipline, according to our basic purpose and goals, and I am grateful.

KEEP READING

We hope you share our confidence. Growth prospects are good for the businesses that will continue to be part of the Dominion family after any sale of our E&P unit. I am enthusiastic about prospects for a timely change in our business mix, and I am proud of the drive and professionalism that all of our employees, including those in E&P, exhibit as they operate these businesses.

Please read about them in the coming pages. And count on our continued commitment to build value for you, the owners of Dominion.

Sincerely,



Thomas F. Farrell II

CONSOLIDATED FINANCIAL HIGHLIGHTS AND KEY MEASURES

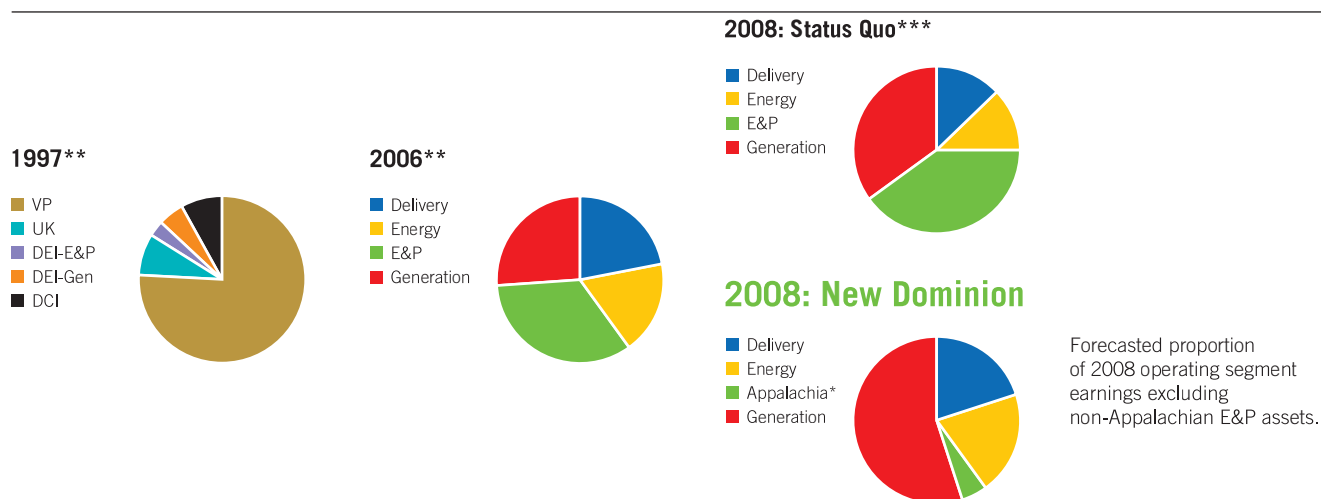
Years Ended December 31,	2006	2005**	% Change
Operating Results (millions)			
Operating revenue	\$ 16,482	\$ 17,971	-8.3%
Reported earnings (GAAP)	1,380	1,033	33.6%
Operating earnings*	1,814	1,572	15.4%
Net cash provided by operating activities	4,005	2,623	52.7%
Data Per Common Share			
Reported earnings (GAAP)	\$ 3.93	\$ 3.00	31.0%
Operating earnings*	\$ 5.16	\$ 4.56	13.2%
Dividends paid	\$ 2.76	\$ 2.68	3.0%
Market value (intraday high)	\$ 84.44	\$ 86.97	-2.9%
Market value (intraday low)	\$ 68.72	\$ 66.51	3.3%
Market value (year-end)	\$ 83.84	\$ 77.20	8.6%
Book value (year-end)	\$ 37.00	\$ 29.93	23.6%
Market to book value (year-end)	2.27	2.58	-12.2%
Financial Position (millions)			
Total assets	\$49,269	\$ 52,660	-6.4%
Total debt	19,601	18,601	5.4%
Common shareholders' equity	12,913	10,397	24.2%
Equity market capitalization	29,257	26,824	9.1%
Other Statistics (shares in millions)			
Return on average common equity—reported	11.4%	9.7%	
Return on average common equity—operating*	15.0%	14.7%	
Common shares outstanding—average, diluted	351.6	344.4	
Common shares outstanding—year-end	349.0	347.5	
Number of full-time employees	17,500	17,400	

* Based on Non-GAAP Financial Measures. See pages 28 and 29 for GAAP reconciliations.

** Prior year's operating earnings have been recast to exclude the discontinued operations of three generation plants for which an agreement to sell was executed in December 2006.

CHANGING EARNINGS MIX

1997 to Future



See page 28 for definitions of abbreviations.

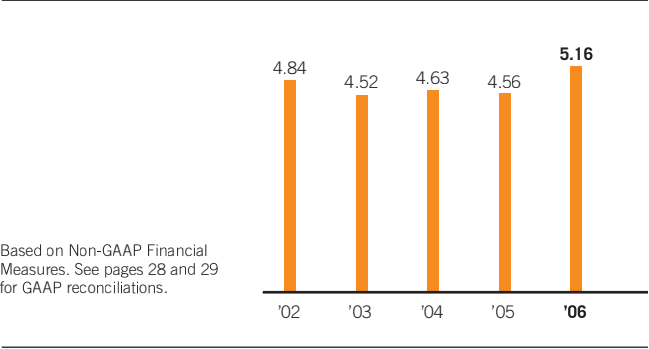
* Excludes earnings from gas and oil production from Dominion Transmission properties included in Dominion Energy.

** Based on Non-GAAP financial measures. See page 29. 1997 operating earnings excludes Holding Company.

*** Forecasted proportion of 2008 operating segment earnings.

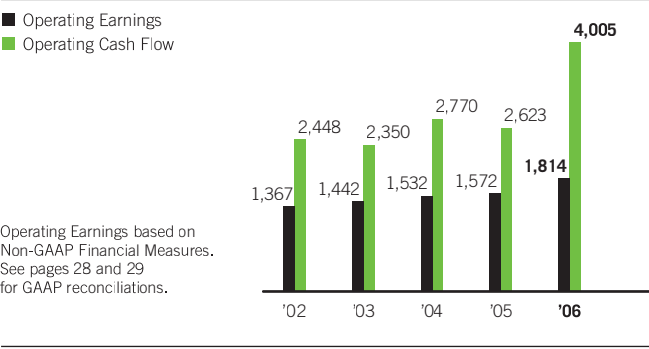
OPERATING EARNINGS PER SHARE

Dollars
As of December 31



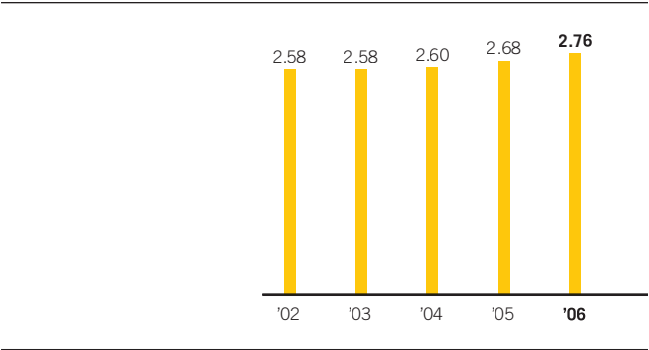
OPERATING EARNINGS & OPERATING CASH FLOW

Millions of Dollars



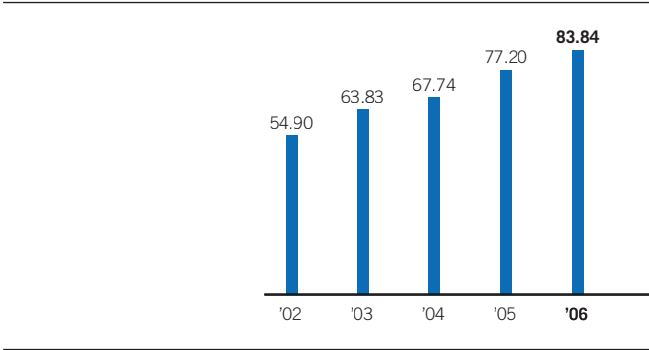
COMMON DIVIDENDS PAID

Dollars Per Share



YEAR-END STOCK PRICE

Dollars Per Share

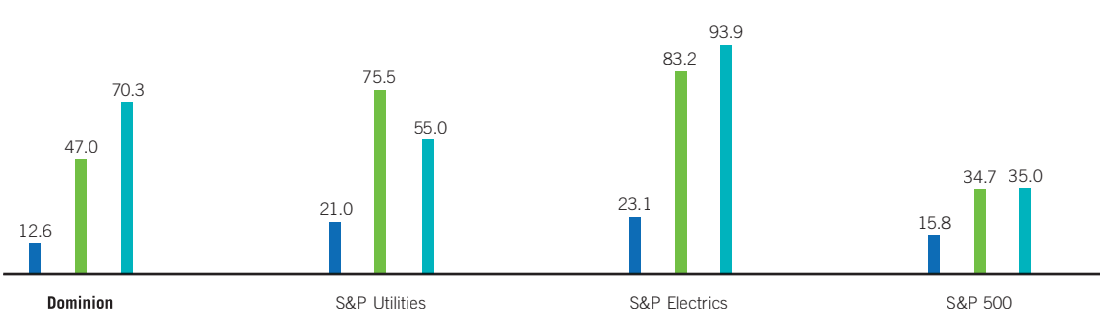


TOTAL RETURN COMPARISON

Percent
Through December 31, 2006

- 1 Year Total Return
- 3 Year Total Return
- 5 Year Total Return

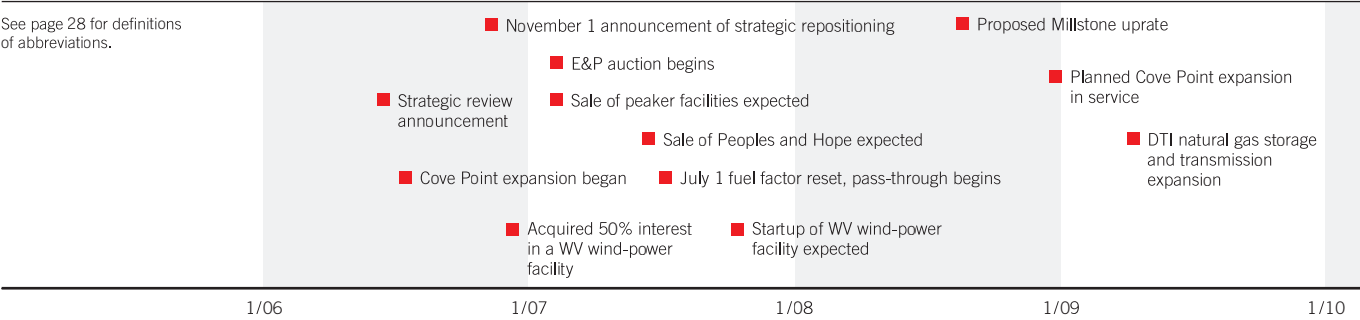
Source: Bloomberg.



A FULL PIPELINE OF OPPORTUNITIES

2006 to 2010

See page 28 for definitions of abbreviations.



Returning to a More Traditional Business Mix

Illustrated here are Dominion’s assets, including E&P assets being considered for sale in 2007. Smaller Dominion businesses being sold under agreements expected to close in 2007 are also shown.

As of December 31

Manufacturing

- 26,384 MW of electric generation
- 1,538 MW of peaking capacity at Troy (OH), Armstrong (PA) and Pleasants (WV) natural gas-fired plants*
- ~5.5 trillion cubic feet equivalent of proved gas reserves**
~1,173 Mmcfe of daily production (non-Appalachian assets being considered for sale in 2007)
- ~1 trillion cubic feet equivalent of proved gas reserves**
~107 Mmcfe of daily production (Appalachian assets not for sale)

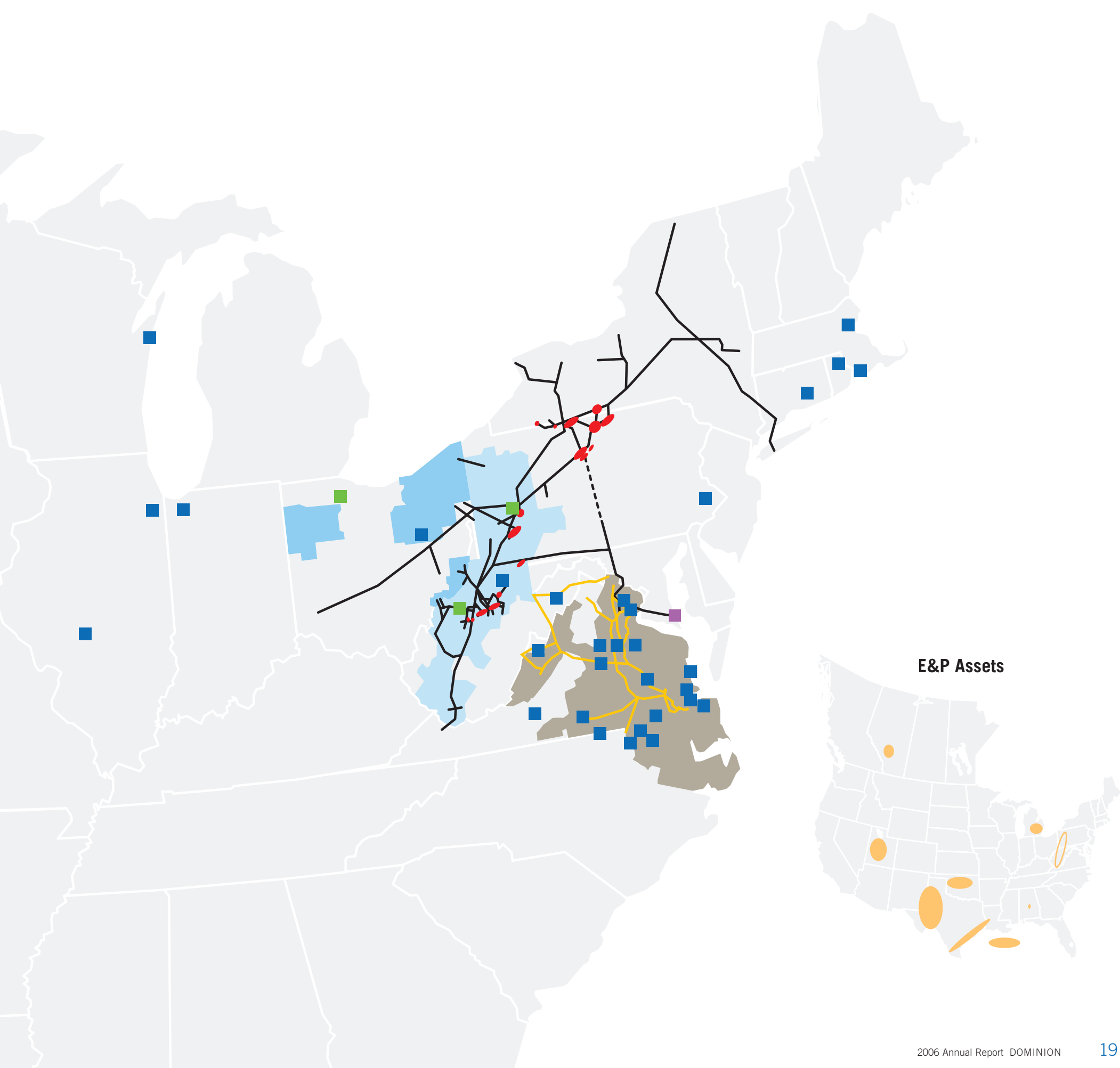
Transportation

- 6,000 miles of electric transmission
- 7,800 miles of natural gas pipeline
- Cove Point expansion pipeline construction to be completed 2008.
- Nearly 1 trillion cubic feet of natural gas storage operated
- Cove Point LNG Facility

Retail

- 4 million franchise gas and electric delivery customer accounts in 5 states
- 2.3 million electric in VA and NC
- 1.2 million natural gas in OH
- 0.5 million natural gas in PA and WV***
- Plus 1.5 million unregulated retail energy customer accounts in 11 states

* The previously announced sale of these plants is expected to close in the first quarter of 2007.
** On November 1, 2006, Dominion announced that it would pursue the sale of its non-Appalachian gas and oil properties. This map differentiates the Appalachian properties from the non-Appalachian properties at year-end 2006. Appalachian proved reserves as of December 31, 2006 ~1 Tcfe. Includes 164 Bcfe of proved reserves owned by Dominion Transmission and reported in Dominion Energy.
*** The previously announced sale of Dominion Peoples (PA) and Dominion Hope (WV) local gas distribution companies is expected to close in the second quarter of 2007.



STRATEGIC REFOCUS ON CORE VALUES AND KEY BUSINESSES

DOMINION DELIVERY:

OUR ANCHOR UTILITY FRANCHISE BUSINESSES

Upon completion of the sale of two smaller natural gas utilities later this year, our company will be anchored by our two major franchise utilities: Dominion Virginia Power and Dominion East Ohio. These two utilities provide electric and gas services to about 3.5 million homes and businesses. Together, they are adding more than 40,000 new customer accounts annually over a 65,000-square-mile service area that includes the major metropolitan areas of suburban Washington, D.C., and the cities of Richmond and Norfolk, Va., and Cleveland, Akron and Canton, Ohio.

Both subsidiaries' retail customer relationships are managed by Dominion Delivery, an operating unit that also includes Dominion Retail, our business that offers competitive pricing in nonregulated energy markets.

Overall, Dominion Delivery is expected to contribute long-term average annual operating earnings growth of between 2 percent and 3 percent. This contribution to Dominion's consolidated projected long-term operating earnings growth rate of 4 percent to 6 percent annually

will be driven by vital economies, constructive regulation and excellent service.

From these utilities, investors can expect steady cash flow that would continue to strengthen Dominion's credit profile.

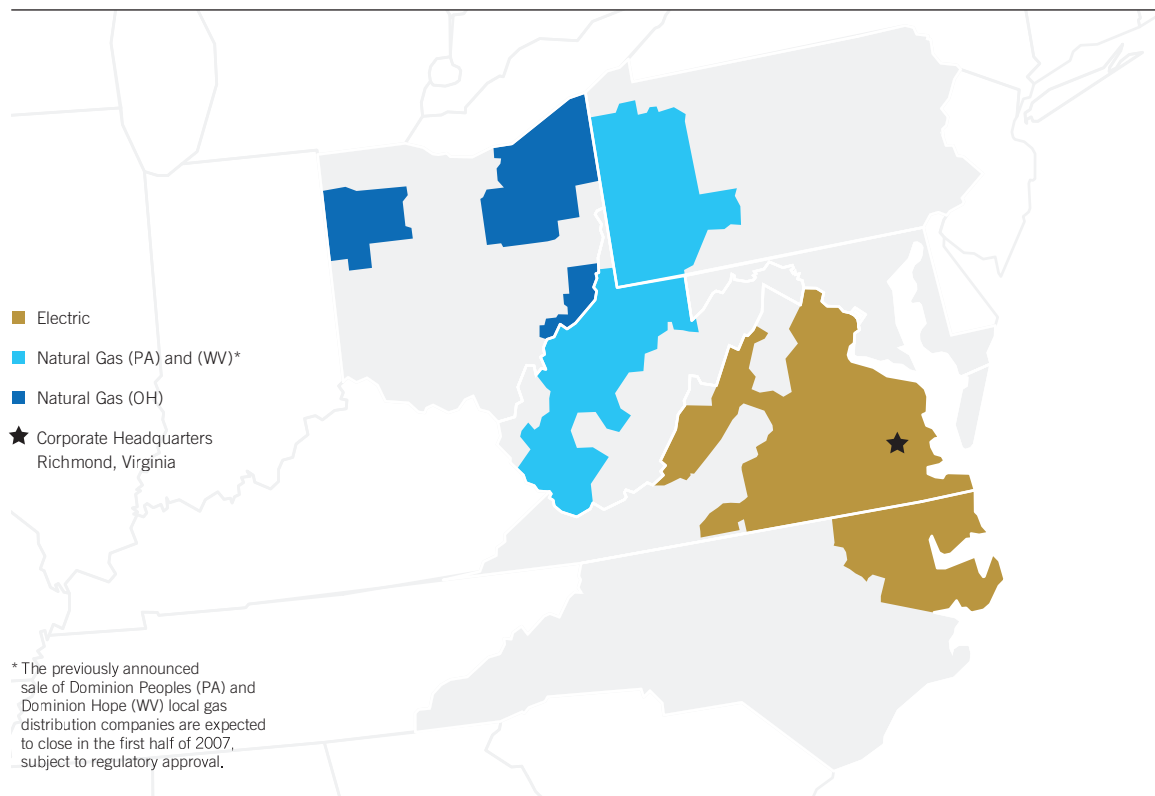
VITAL ECONOMIES

Dominion Virginia Power serves more than 2.2 million homes and businesses in Virginia and about 100,000 in northeast North Carolina as Dominion North Carolina Power. Demand for power will only increase as Virginia's population grows at an annual rate of nearly 7 percent. In fact, Virginia—which includes the nation's fastest growing region for high-tech jobs—exceeds the U.S. growth rate by 1.5 percentage points. Ranked No. 1 among "Top States for Business" by Forbes.com, Virginia ranks 10th in terms of low tax burden. It is one of only seven states with a AAA bond rating.

Dominion East Ohio is one of Ohio's largest natural gas distribution companies, serving more than 1.2 million residential, commercial and industrial customers in Cleveland and other Ohio markets. The unit operates more than 19,000 miles of natural gas transmission, distribution and gathering lines in a service area covering more than 4,700 square miles.

REGULATED UTILITIES SERVICE AREAS

As of December 31



CONSTRUCTIVE REGULATION

Longtime owners of Dominion know that we have a history of working constructively with Virginia legislators and regulators to promote public policies that benefit both customers and investors.

For example, 2006 legislation in Virginia will allow Dominion Virginia Power to begin fully recovering the rising cost of fuel to fire its power-generation fleet and purchased power. Under deregulation, laws did not fully cover rising fuel costs and purchased power. As a result, our after-tax earnings were reduced by \$404 million in 2005 and \$364 million in 2006.

In early 2007, Virginia lawmakers adopted legislation supported by Dominion that would end rate caps on base rates—the non-fuel portion of a customer’s bill—at the end of 2008. Dominion’s base rates have been capped by law since 1999 as part of what was to be a transition to competitive markets. But competition failed to develop as expected and the company and other stakeholders supported a return to cost-of-service regulation in Virginia with incentives for building generation to serve Virginia. The bill was before the governor for review and approval, amendment or veto as we went to press.

Dominion’s allowed rate of return would be set in a manner that will allow us to attract necessary capital for new generation while providing financial incentives to continue efficient and reliable operations. This model would continue to give our customers stable rates and enable them to share in any overearnings by the company. Incentives for renewables, demand-side management, solar and wind are also part of the 2007 regulatory model.

AUTHORIZED RETURNS AT DOMINION EAST OHIO

Under regulation in Ohio, Dominion East Ohio earns an authorized rate of return on the costs of maintaining and operating the distribution system and billing. Fuel costs are passed through to consumers without profit.

To support the growth of competitive energy markets and low prices for our natural gas utility customers, Dominion East Ohio allows its customers to buy gas from other suppliers. Since the Energy Choice Program was adopted in 2000, about 70 percent of our customers now buy natural gas from competitive providers. As Dominion East Ohio exits this business, known as the “merchant function,” it will continue to distribute and deliver the gas and process bills. Dominion East Ohio’s authorized rate of return and earnings have not been

affected. Yet customers control the portion of their gas bill tied to the cost of natural gas, which represents about two-thirds of the total.

TOP-NOTCH SERVICE

We take our franchise responsibilities seriously. We have to earn the right to serve our customers. We measure our customer service through reliability, telephone center accessibility and accurate meter reading and billing, among other standards. One of the most visible performance measures is to be there when electric customers throw the light switch: A typical customer had power 99.98 percent of the time in 2006, excluding major storms. This continues a positive trend that we will keep working to improve. Each year at Dominion Virginia Power we invest more than \$100 million to bolster reliability and clear rights-of-way for our 55,000 miles of neighborhood lines.

For customers in Ohio who continued to choose us to purchase the most competitively priced gas supply, we reached a milestone in 2006. We became the first gas company to acquire supply through an innovative Internet-based auction process. The result? A purchase price well below the cost that we would have incurred under a more traditional approach.

THE REAL BOTTOM LINE: SAFETY

Safety is our real bottom line. We expect our employees to look out for each other. This culture fosters the proper environment for safe service to our customers. With the introduction of analytical tools drawn from our Six Sigma process-improvement program, accident prevention initiatives reduced injuries in the gas and electric businesses by 35 percent in 2006 and 60 percent since 2004. At the same time, the severity of injuries has dropped by 64 percent.

DOMINION RETAIL SELLS POWER, GAS IN COMPETITIVE MARKETS

Dominion Retail began selling electricity and natural gas in New York and electricity in Maryland in 2006. Residents there with an option to choose energy-related products and services are turning to Dominion Retail as others have already done in six other states.

Dominion Retail serves 1.5 million customer accounts and it moved to grow by soliciting more than 10 million households. When choice is an option, Dominion Retail wants to be there.

DOMINION GENERATION:

STRONG AND GROWING STRONGER

Our Dominion Generation business will manage more than 26,300 megawatts of electricity production after it completes the sale of three merchant peaking facilities in 2007. About 65 percent supports our Virginia and North Carolina regulated electric business, while the remaining 35 percent serves nonregulated customers in the Northeastern and Midwestern United States. After completion of the proposed E&P sale, Dominion Generation is expected to make up about 55 percent of our company's operating earnings.

On average, we expect long-term operating earnings growth of 5 percent to 6 percent annually. Driving this growth will be continued efficiency gains and expansions at our existing facilities, new construction supporting a fast-growing economy in Virginia and a continued practice of acquiring new assets that build shareholder value.

LARGE AND GROWING PRESENCE IN NEW ENGLAND

Our nonregulated operations today are concentrated in the Northeast. In New England, our portfolio of generating stations is the largest, most fuel-diverse and competitive in the region. These stations include our two nuclear units at Millstone Power Station in Connecticut, a fleet of

coal and oil units at our Brayton Point and Salem Harbor power stations in Massachusetts, and gas-fired units at our Manchester Street Station in Rhode Island. These low-cost generating stations provide us with a competitive advantage in a power market driven by natural gas. With strong electric load growth projected in this region and limited opportunity to add new generation, these assets will grow even more valuable in the future.

BRIGHT FUTURE IN MIDWEST

We also see a bright future for our fossil-fuel and nuclear facilities operating in the Midwest. These baseload and peaking stations benefit from strategic locations. Together, they generate more than 2,900 megawatts of power, which is sold under long-term contracts.

SAFE AND EFFICIENT NUCLEAR OPERATOR

A long-standing reputation for superior nuclear operating performance provides us with a competitive advantage at Dominion Generation. Last year, *Platts Nucleonics Week*, a McGraw-Hill publication, named our North Anna and Surry nuclear power stations first and third among the nation's most-efficient nuclear generating units for the period from 2003 through 2005. These same units were rated among the top 10 low-cost producers the previous year.

Among the highlights of our 2006 nuclear performance were:

- Three of our nuclear stations achieved "Star" safety status from the U.S. Department of Labor's Occupational Safety & Health Administration, and Kewaunee is recommended—the first fleet in the country expected to accomplish this.
- Millstone achieved in excess of 7 million work-hours without a lost-time accident. In addition, since acquisition, Kewaunee's industrial safety accident rate was reduced by more than 75 percent.
- Millstone Unit 3 reached 393 consecutive days online at year-end.
- Surry Unit 2 achieved a record 502 consecutive days online.
- Our North Anna units had overall capacity factors of 93.9 percent.

OUR FOSSIL FLEET:

BELOW-THE-RADAR EXCELLENCE

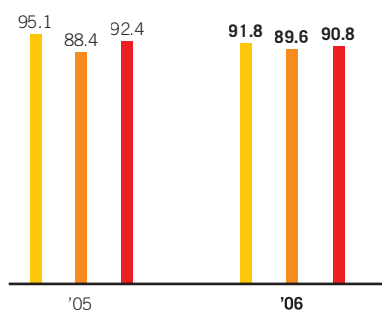
Although our nuclear fleet may get most of the headlines, no one should overlook the stellar performance of our fossil operations, which include facilities fueled by coal,

MANUFACTURING—MAINTAIN EXCELLENT OPERATIONS

Percent
For the Year Ended December 31

Dominion Nuclear Capacity Factor

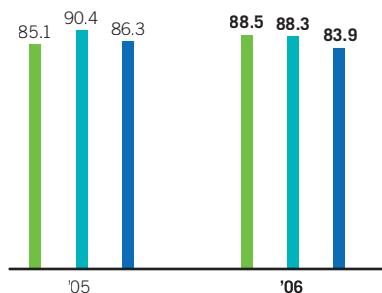
■ Virginia Nuclear
■ Merchant Nuclear
■ Total Nuclear



Dominion Coal Equivalent Availability

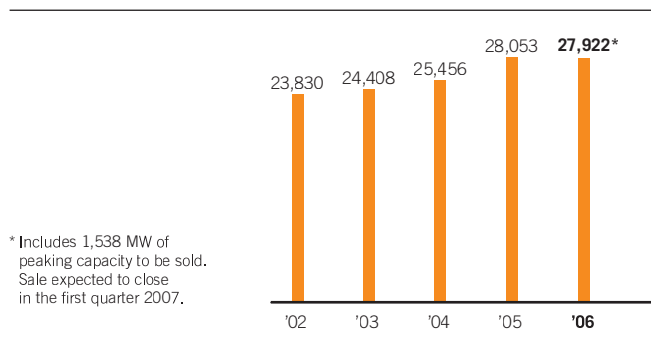
■ Utility Large Coal*
■ Utility Small Coal*
■ Merchant Coal

* Large coal units are >300 megawatts (MW).
Small coal units are < 300 MW.



ELECTRIC GENERATION CAPACITY

Megawatts



natural gas and oil. The fossil group also manages facilities using hydroelectric power and other sources. This fleet's outstanding performance in 2006 enabled us to meet a record for customer demand on Aug. 3, when peak load in Virginia reached 19,375 megawatts. That topped the record of 18,897 megawatts set July 27, 2005. Our large utility coal units attained production levels that were the best in six years and the second-best on record. Our outstanding Virginia fossil fleet performance achieved availability levels of 89.3 percent, even better

than our previous year's performance, which was well above most of our peers.

In addition, we saw record safety performance at our Brayton Point and Roanoke Rapids facilities, all while we continued to reduce emission levels across our fleet with our environmental controls programs.

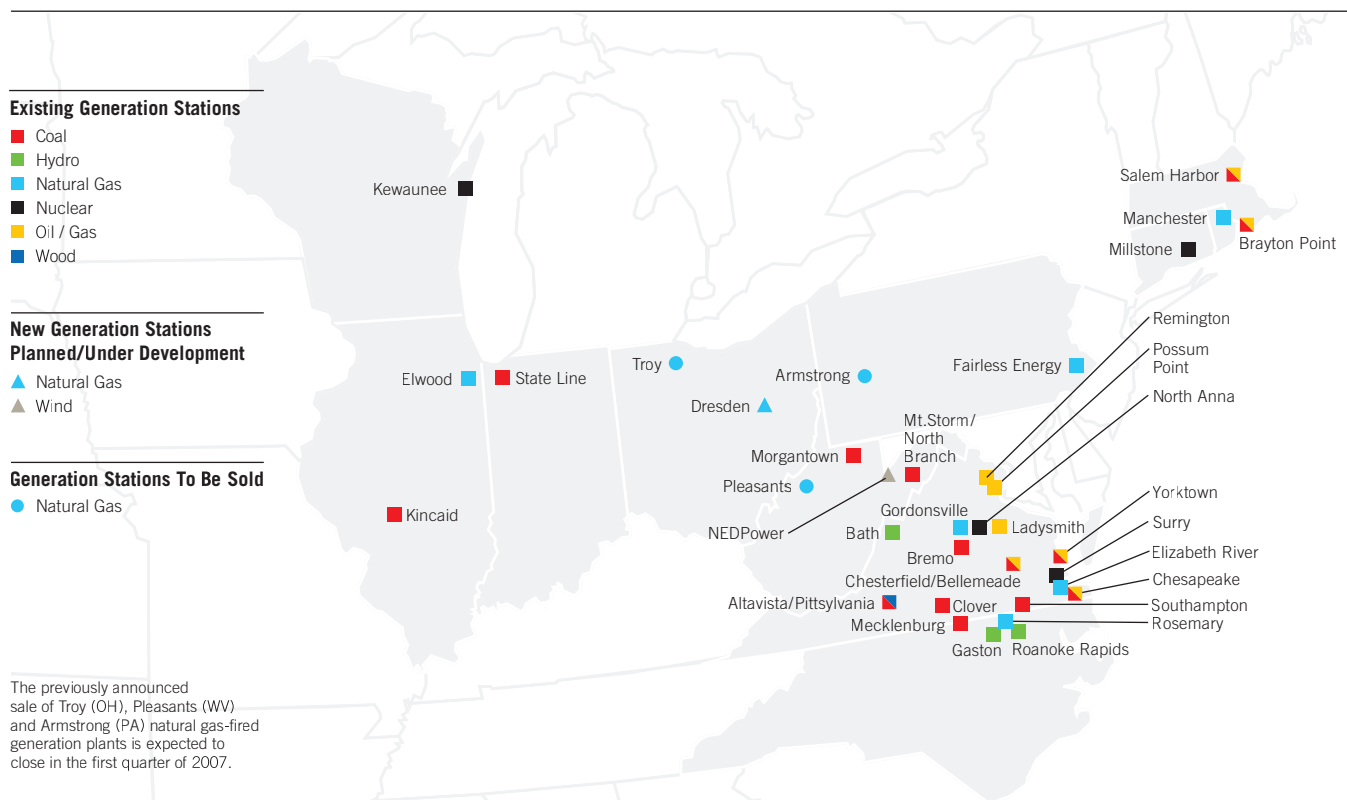
EXPANSION AND GROWTH OPPORTUNITIES

Looking ahead, Dominion is working to obtain approvals for a possible third reactor at our North Anna Power Station site. This unit would be built only if requisite regulatory and financial conditions are in place. Additionally, Dominion Virginia Power is pursuing the construction of a facility to be fired with clean coal in Southwest Virginia and evaluating additional gas-fired generation to help serve a growing Northern Virginia market. We are also increasing our generation output in a number of facilities through efficiencies and improvements. These include units run with coal, gas and nuclear fuel.

Dominion Generation's excellent operations, strategically located assets and sound growth plan provide a solid foundation and a very optimistic future.

CURRENT GENERATION PORTFOLIO (MAJOR DOMINION OPERATIONS)

As of December 31



DOMINION ENERGY:**EXPANDING ENERGY INFRASTRUCTURE IN THE EAST**

Our Dominion Energy operating unit includes our natural gas pipeline and storage business, our liquefied natural gas (LNG) terminal at Dominion Cove Point, and our electric transmission assets. In industry terms, we refer to these as “mid-stream assets” because they link energy production with energy users.

We project that Dominion Energy’s long-term operating earnings growth rate will average between 5 percent and 6 percent. This rate is the outgrowth of a pressing market reality: New pipelines and storage are urgently needed to bring additional supplies of natural gas to the Northeast and mid-Atlantic regions. At the same time, significant investment in electric transmission will be

required to meet Virginia’s energy demand. Through Dominion Energy, we serve these markets with reliable facilities that are now being expanded to increase the amount of energy delivered.

IMPORTED LNG TO MEET GROWING DEMAND FOR NATURAL GAS

At the heart of our growth is Dominion Cove Point, our LNG import and storage facility in Maryland on the Chesapeake Bay. Each day the facility is capable of sending out 1 billion cubic feet of natural gas. It features storage capacity of 7.8 billion cubic feet.

By late 2008, when an expansion is complete, the total storage capacity at the site will have increased by more than 80 percent, to 14.6 billion cubic feet. Daily sendout capability will be increased to 1.8 billion cubic feet. All the new capacity has been subscribed under long-term contracts with Norwegian energy giant Statoil. We are expanding pipelines from Cove Point to connect with federally regulated pipelines that carry the gas to local markets and storage facilities. Dominion Energy collects revenues from the storage, revaporization and transmission of the gas.

STORAGE AND PIPELINE EXPANSIONS TO GROW RATE BASE

In addition, storage and pipeline expansions are under way in West Virginia, New York and Pennsylvania. When Dominion Cove Point’s expansion and these other projects are completed, the company will have more than doubled its gas transmission rate base, from \$1.2 billion in 2001 to a planned \$2.9 billion in 2008. Once finished, the projects will have added 3.8 million dekatherms per day of transportation capacity and 35 billion cubic feet of natural gas storage to Dominion Energy.

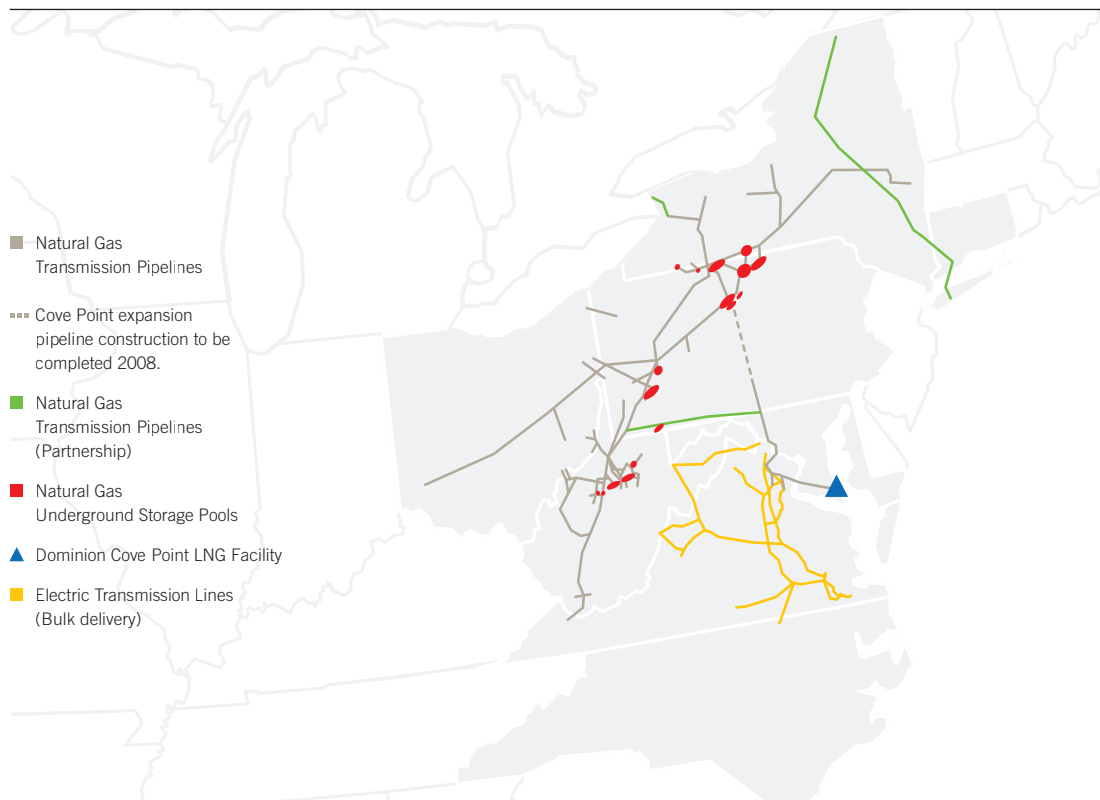
While most studies show average annual natural gas consumption on the decline because of higher-efficiency equipment, daily consumption at peak hours of use continues to grow. Even with conservation efforts to control demand, we anticipate the need for even more storage and pipeline projects in the future to meet these increases. Building on the strength of our strategic location, we have identified potential growth projects that could double this rate base again over the coming years.



The natural gas pipeline business uses “smart pigs” to inspect pipelines. The “smart pigs” travel inside the pipeline with the gas stream to collect data on the condition of the pipe. Electronic sensors in a “smart pig” provide gigabytes of data, such as the number and length of pipe line joints and fittings, pipe wall thickness, and the number and location of valves and welds.

GAS TRANSMISSION PIPELINES & STORAGE/ELECTRIC TRANSMISSION LINES

As of December 31



ELECTRIC TRANSMISSION EXPANSION

Many opportunities exist to grow our 6,000-mile electric transmission system as well. On page 20, we describe the robust economic growth occurring in Virginia's economy. To meet the demand associated with that growth, a significant investment in high-voltage transmission infrastructure is required over the next five to seven years. In all instances, we are committed to finding the best routes and applying the best technologies to minimize local impacts and meet customer needs.

MAINTAINING BEST-IN-CLASS SYSTEM INTEGRITY

These vital energy transportation arteries are maintained and inspected under a system that ensures they operate at unparalleled levels of integrity. We also exceed federal requirements on the natural gas transportation side in the way we go about inspecting our compressor and storage facilities and moving swiftly to remedy potential problems. With the help of advanced technology mounted on a helicopter, the electric transmission team inspects and maintains more than 4,500 miles of our 6,000-mile electric transmission system each year. This method is much

more efficient than the days in which our energetic employees had to conduct inspections the old-fashioned way—on foot, with hand-held instruments. Back then, we could inspect only 1,200 miles every year.

PROVIDING OTHER SERVICES WITHOUT UTILIZING CAPITAL EXPENDITURES

Dominion Energy also includes a business that we refer to as producer services. It provides a range of wholesale natural gas supply management services to Dominion affiliates, local utilities, companies that aggregate natural gas supplies for retail sales and Appalachian producers. Our producer services group does not utilize capital expenditures for growth; instead, it contributes by providing third-party storage and transportation services.

As Americans go about their lives and commerce in cities, towns and rural areas across the mid-Atlantic and Northeast regions, Dominion Energy is reliably linking energy producers with energy users around the clock.

APPALACHIAN NATURAL GAS ASSETS:**"OLD FAITHFUL"**

Even if we sell the bulk of our E&P business, we intend to keep our E&P assets in West Virginia, Pennsylvania, Ohio, New York, Virginia and Kentucky because they are the company's own "Old Faithful." Dominion's Appalachian natural gas and liquids production business is expected to contribute less than 5 percent of Dominion's consolidated operating income after the sale of our other oil and natural gas assets.

HIGHER MARKET PRICES, LOWER TRANSPORTATION COSTS

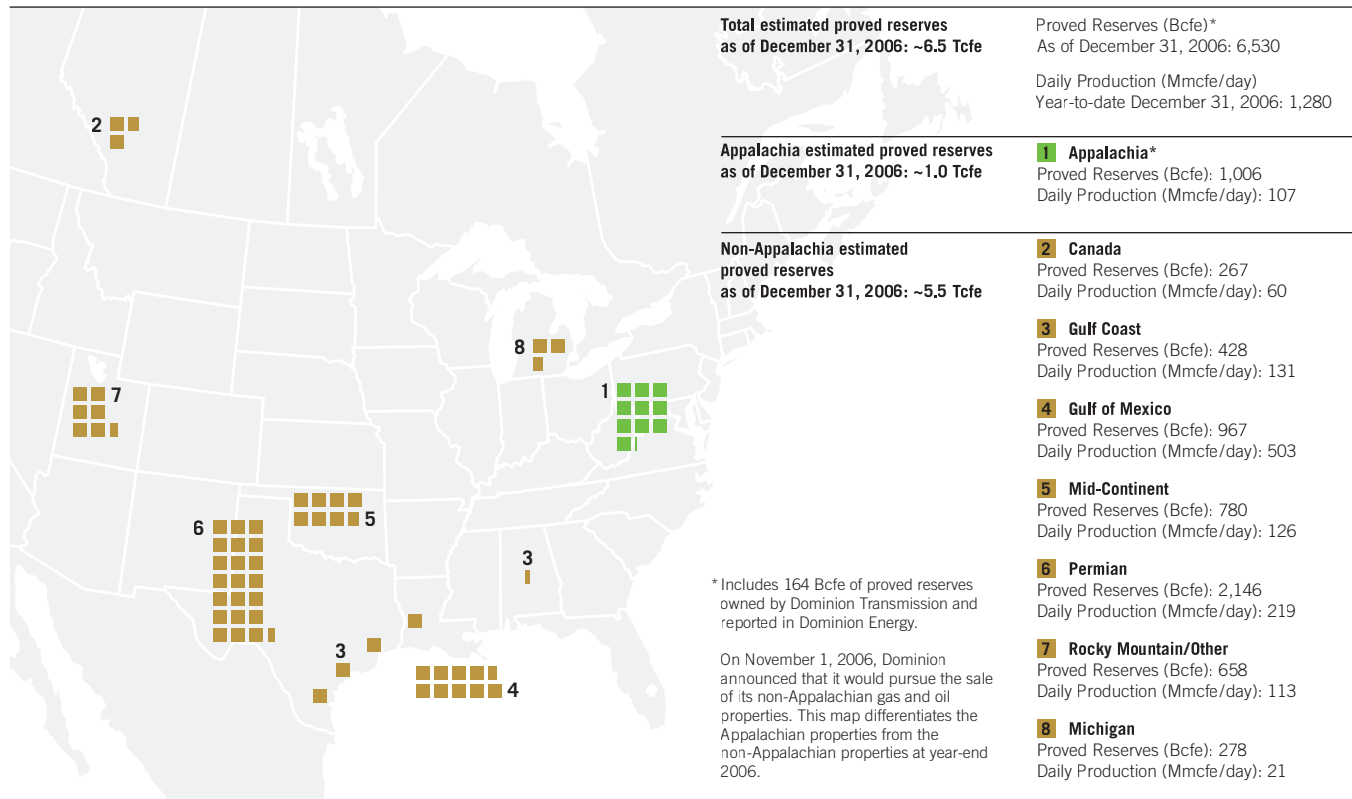
These 9,000 producing wells are close to the premium natural gas-consuming markets in the Northeast. With existing links to distribution systems and storage fields

and access to pipelines and processing plants, their production benefits from low transportation costs and higher-than-average market prices.

Our Appalachian reserves are estimated at year-end 2006 to have more than 1 trillion cubic feet of natural gas equivalent and an average daily production of 107 million cubic feet of natural gas equivalent. In other words, our Appalachian Basin wells are expected to produce for quite a long time, with production declining an average of only 5 percent a year. Some wells, like No. 1, our oldest, have been producing for 100 years. The average life of our Appalachian proved reserves is nearly 26 years, compared with the 7-year average life span of a typical well in the Gulf of Mexico. Owning long-life reserves greatly reduces the financial risk of exploring for new reserves to replace depleted reservoirs.

DOMINION EXPLORATION & PRODUCTION RESERVE LOCATIONS

■ = 100 Bcfe



LOW-COST DRILLING AT HIGH SUCCESS RATE

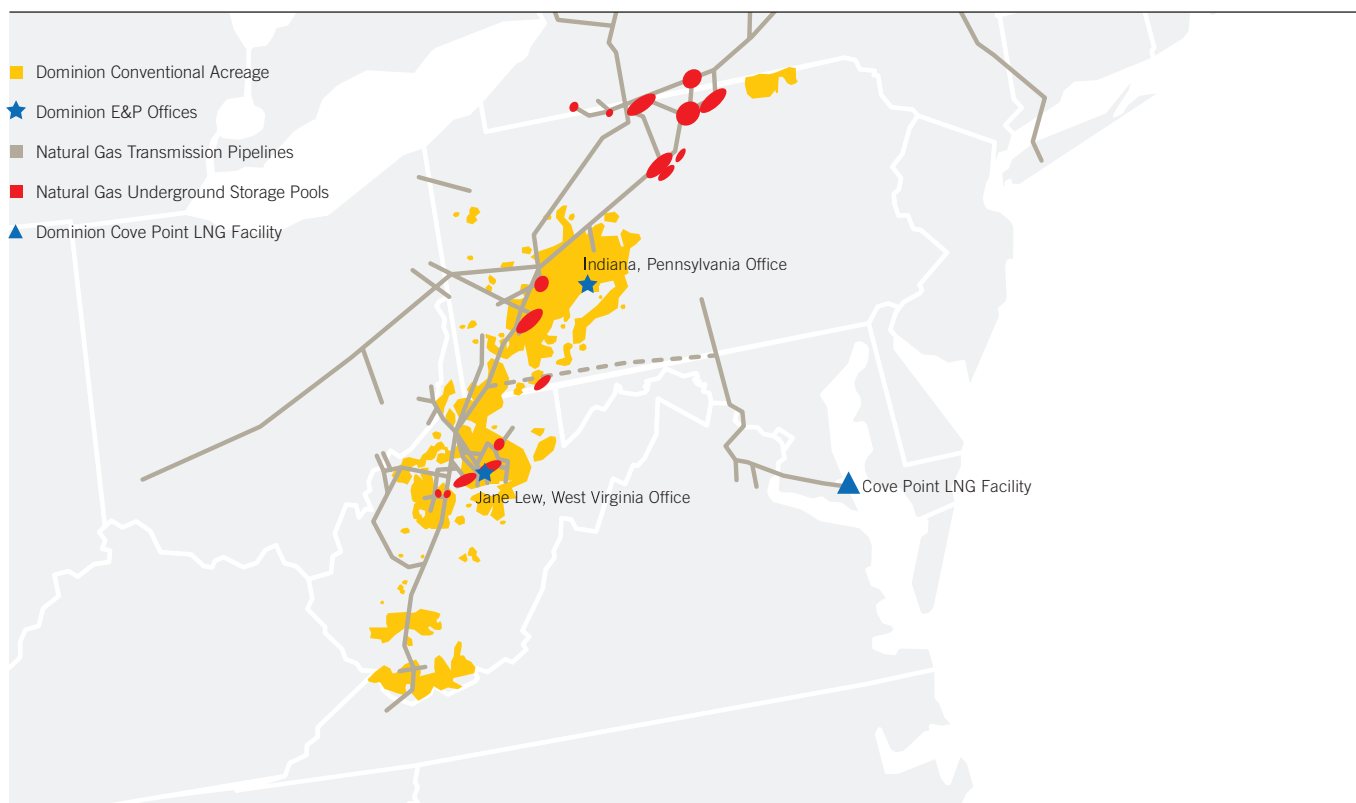
The cost of drilling a well in the Appalachian Basin is relatively low, while the drilling success rate is very high: Dominion has enjoyed a 98 percent success rate in the region for many years.

Room for steady growth remains. Dominion has 7,000 prospective drilling sites in the Appalachian Basin, with plans to continue drilling about 300 wells a year. Most of these conventional wells are found in an established reservoir, the Upper Devonian sandstone. But we have new technology that enables us to drill deeper as well as extract coal bed methane and other non-conventional fuel sources if market prices provide incentives to do so.



Dominion's Appalachian Basin assets include more than 9,000 producing wells close to premium natural gas-consuming Northeast markets.

APPALACHIAN ACREAGE WELL-POSITIONED



**Consolidated Dominion Resources, Inc.—
Reconciliation of Operating Earnings to Reported Earnings (GAAP)**

	2002*		2003*		2004*		2005*		2006	
	Millions	EPS	Millions	EPS	Millions	EPS	Millions	EPS	Millions	EPS
Operating Earnings	\$ 1,367	\$ 4.84	\$ 1,442	\$ 4.52	\$ 1,532	\$ 4.63	\$ 1,572	\$ 4.56	\$ 1,814	\$ 5.16
After-tax items:										
Charges related to pending sale of gas distribution subsidiaries	—	—	—	—	—	—	—	—	(73)	(0.21)
Dominion Capital related charges	(8)	(0.03)	(81)	(0.25)	(61)	(0.18)	(22)	(0.06)	(91)	(0.26)
Income (loss) from discontinued operations of merchant generation plants	(2)	(0.01)	7	0.03	(9)	(0.02)	(14)	(0.03)	(183)	(0.52)
Income (loss) related to Telecom business	—	—	(750)	(2.35)	(13)	(0.04)	5	0.02	—	—
Termination of power purchase contracts	—	—	(65)	(0.20)	(43)	(0.13)	(44)	(0.13)	—	—
Charges related to hurricanes	—	—	(122)	(0.38)	(50)	(0.15)	(375)	(1.09)	(11)	(0.03)
Charges related to exiting certain businesses	—	—	(69)	(0.22)	(86)	(0.27)	(12)	(0.04)	(6)	(0.02)
Other asset impairments	—	—	—	—	(5)	(0.01)	(68)	(0.20)	(40)	(0.11)
Cumulative effect of changes in accounting principles	—	—	11	0.03	—	—	(6)	(0.02)	—	—
Other items	5	0.02	(55)	(0.18)	(16)	(0.05)	(3)	(0.01)	(30)	(0.08)
Total after-tax items	(5)	(0.02)	(1,124)	(3.52)	(283)	(0.85)	(539)	(1.56)	(434)	(1.23)
Reported Earnings (GAAP)	\$ 1,362	\$ 4.82	\$ 318	\$ 1.00	\$ 1,249	\$ 3.78	\$ 1,033	\$ 3.00	\$ 1,380	\$ 3.93

* Prior years' operating earnings have been recast to exclude the discontinued operations of three natural gas-fired generation plants for which an agreement to sell was executed in December 2006.

**Reconciliation of Measures Prepared in Accordance with Generally Accepted Accounting Principles (GAAP) Versus Non-GAAP Measures¹
Ratio of Total Debt to Total Capitalization**

	GAAP Measure at 12/31/05		Adjusted at 12/31/05		GAAP Measure at 12/31/06		Adjusted at 12/31/06	
(dollars in millions)								
Securities due within one year	\$ 2,330		\$ 2,330		\$ 2,478		\$ 2,478	
Short-term debt	1,618		1,618		2,332		2,332	
Long-term debt:								
Equity-linked debt securities	330		330		—		—	
Junior subordinated notes payable to:								
Affiliates	1,416		—		1,151		—	
Other	—		—		798		399	
Non-recourse debt (FIN 46 consolidation)	—		—		385		—	
Other long-term debt	12,907		12,907		12,457		12,457	
Long-term debt—total	14,653		13,237		14,791		12,856	
Total debt	18,601	63.6%	17,185	58.1%	19,601	59.8%	17,666	54.5%
Preferred stock	257		257		257		257	
Junior subordinated notes payable to:								
Affiliates	—		1,416		—		1,151	
Other	—		—		—		399	
Common shareholders' equity:								
Common stock	11,286		11,286		11,250		11,250	
Other paid-in capital	125		125		128		128	
Retained earnings	1,550		1,550		1,960		1,960	
Accumulated other comprehensive loss	(2,564)		(2,564)		(425)		(425)	
Common shareholders' equity—total	10,397		10,397		12,913		12,913	
Equity-linked debt securities	—		330		—		—	
Total equity and preferred stock	10,654	36.4%	12,400	41.9%	13,170	40.2%	14,720	45.5%
Total capitalization	\$29,255		\$29,585		\$32,771		\$32,386	

(1) Regulation G of the SEC's rules require reconciliations to U.S. GAAP measures for certain publicly disclosed financial information. This schedule is presented to meet the requirements of Regulation G.

Page 16: Definitions of abbreviations

VP: Virginia Electric and Power Company

UK: United Kingdom

DEI-E&P: Dominion Energy, Inc.—Exploration & Production

DEI-Gen: Dominion Energy, Inc.—Generation

DCI: Dominion Capital, Inc.

Page 17: Definitions of abbreviations and terms

E&P: Exploration & Production

DTI: Dominion Transmission, Inc.

Proposed Millstone Uprate: would increase power output by 74 megawatts (MW)

**Reconciliation of Operating Return on Equity
to Reported Return on Equity**

	2005		2006	
	Millions	%	Millions	%
Common Shareholders' Equity—13 mos. average	\$10,693		\$12,059	
Operating Earnings— Twelve months ended*	1,572		1,814	
Return on average common equity—operating		14.7%		15.0%
Reported Earnings— Twelve months ended	1,033		1,380	
Return on average common equity—reported		9.7%		11.4%

* See Reconciliation of Operating Earnings to Reported Earnings.

**Reconciliation of 2006 Segment Operating Earnings
to Reported Earnings (GAAP)**

	Operating Earnings		Reported Earnings	
	Millions	%	Millions	%
Dominion Delivery	\$ 438	22	\$ 438	32
Dominion Generation	537	26	537	39
Dominion Energy	360	18	360	26
Dominion E&P	680	34	680	49
Primary operating segments	2,015	100	2,015	146
Corporate	(201)		(635)	(46)
Consolidated	\$1,814		\$1,380	100

* See Reconciliation of Operating Earnings to Reported Earnings.

**Reconciliation of 1997 Operating Earnings
to Reported Earnings (GAAP)**

	Operating Earnings		Reported Earnings	
	Millions	%	Millions	%
Dominion Capital	\$ 45	8	\$ 45	11
Virginia Power	433	76	433	109
Dominion UK*	46	8	(111)	(28)
DEI-E&P	17	3	17	4
DEI-Generation	28	5	28	7
	\$ 569	100	\$ 412	103
DRI Holding Co.	(13)		(13)	(3)
Consolidated	\$ 556		\$ 399	100

* Dominion UK operations earnings exclude \$157 million of windfall profits tax.

2006 FINANCIAL CONTENTS

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For factors that could cause actual results to differ, see Forward-Looking Statements, Risk Factors and Market Risk Sensitive Instruments and Risk Management in Management's Discussion and Analysis of Financial Condition and Results of Operations in this report.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) discusses our results of operations and general financial condition. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms "Dominion," "Company," "we," "our" and "us" are used throughout this report and, depending on the context of its 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.

CONTENTS OF MD&A

The reader will find the following information in our MD&A:

- Forward-Looking Statements
- Introduction
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Selected Information—Energy Trading Activities
- Liquidity and Capital Resources
- Future Issues and Other Matters
- Market Risk Sensitive Instruments and Risk Management
- Risk Factors
- Selected Financial Data

FORWARD-LOOKING STATEMENTS

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

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

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes and winter storms, that can cause outages, production delays and property damage to our facilities;
- State and federal legislative and regulatory developments, including a movement towards a hybrid form of regulation, and changes to environmental and other laws and regulations to which we are subject;
- Cost of environmental compliance;
- Risks associated with the operation of nuclear facilities;
- Fluctuations in energy-related commodity prices and the effect these could have on our earnings, liquidity position and the underlying value of our assets;
- Counterparty credit risk;
- Capital market conditions, including price risk due to marketable securities held as investments in nuclear decommissioning and benefit plan trusts;

- Fluctuations in interest rates;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Changes in our ability to recover investments made under traditional regulation through rates;
- Receipt of approvals for and timing of closing dates for acquisitions and divestitures, including our divestiture of The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope) and any divestiture of our exploration and production (E&P) business;
- Risks associated with any realignment of our operating assets, including the potential dilutive effect on earnings in the near term, costs associated with any sale of our E&P business and the costs and reinvestment risks related to deployment of proceeds from any sale;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;
- Completing the divestiture of investments held by our financial services subsidiary, Dominion Capital, Inc. (DCI);
- Additional risk exposure associated with the termination of business interruption and offshore property damage insurance related to our E&P operations and our inability to replace such insurance on commercially reasonable terms; and
- Changes in rules for regional transmission organizations (RTOs) in which we participate, including changes in rate designs and new and evolving capacity models.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in *Risk Factors*.

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

INTRODUCTION

Dominion is a fully integrated gas and electric holding company headquartered in Richmond, Virginia. Our strategy is to be a leading provider of electricity, natural gas and related services to customers in the eastern region of the United States (U.S.). Our portfolio of assets includes approximately:

- 28,000 megawatts (Mw) of generation capacity;
- 7,800 miles of interstate natural gas transmission, gathering and storage pipeline;
- 6,000 miles of electric transmission lines;
- 55,000 miles of electric distribution lines in Virginia and North Carolina;
- 6.5 trillion cubic feet equivalent of proved gas and oil reserves; and
- An underground natural gas storage system with 979 billion cubic feet of capacity.

Our businesses are managed through four primary operating segments: Dominion Delivery, Dominion Energy, Dominion Generation and Dominion E&P. The contributions to net income by our primary operating segments are determined based on a measure of profit that we believe represents the segments' core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by management in assessing segment performance or allocating resources among the segments. Those specific items are reported in the Corporate segment.

Dominion Delivery includes our regulated electric and gas distribution and customer service businesses, as well as non-regulated retail energy marketing operations. Our electric distribution operations serve residential, commercial, industrial and governmental customers in Virginia and northeastern North Carolina. Our gas distribution operations serve residential, commercial and industrial gas sales and transportation customers in Ohio, Pennsylvania and West Virginia. Our nonregulated retail energy marketing operations market gas, electricity and related products and services to residential, small commercial and industrial customers in the Northeast, Mid-Atlantic and Midwest.

Revenue provided by our electric and gas distribution operations is based primarily on rates established by state regulatory authorities and state law. The profitability of these businesses is dependent on their ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings relates largely to changes in volumes, which are primarily weather sensitive, and changes in the cost of routine maintenance and repairs (including labor and benefits). Income from retail energy marketing operations varies in connection with changes in weather and commodity prices, as well as the acquisition and loss of customers.

In March 2006, we entered into an agreement with Equitable Resources, Inc. to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope for approximately \$970 million plus adjustments to reflect capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is expected to close by the end of second quarter of 2007, subject to state regulatory approvals in Pennsylvania and West Virginia, as well as approval under the Hart-Scott-Rodino Act.

Dominion Energy includes our regulated electric transmission, natural gas transmission pipeline and storage businesses and the Cove Point liquefied natural gas (LNG) import and storage facility. It also includes gathering and extraction activities, as well as certain Appalachian natural gas production. Dominion Energy includes producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage, associated gas trading and results of certain energy trading activities exited in December 2004. The electric transmission business serves Virginia and northeastern North Carolina. In 2005, we became a member of PJM Interconnection, LLC (PJM), an RTO, and integrated our electric transmission facilities into PJM wholesale electricity markets. The gas transmission pipeline and storage business serves our gas distribution businesses and other customers in the Northeast, Mid-Atlantic and Midwest.

Revenue provided by our regulated electric and gas transmission operations and the LNG facility is based primarily on rates established by the Federal Energy Regulatory Commission

(FERC). The profitability of these businesses is dependent on our ability, through the rates we are permitted to charge, to recover costs and earn a reasonable return on our capital investments. Variability in earnings results from changes in rates and the demand for services, which is primarily weather dependent.

Earnings from Dominion Energy's nonregulated businesses are subject to variability associated with changes in commodity prices. Dominion Energy's nonregulated businesses use physical and financial arrangements to attempt to hedge this price risk. Certain hedging and trading activities may require cash deposits to satisfy collateral requirements. Variability in earnings also results from changes in operating and maintenance expenditures (including labor and benefits).

Dominion Generation includes the generation operations of our electric utility and merchant fleet and utility energy supply, energy marketing and price risk management activities for our generation assets. Our generation mix is diversified and includes coal, nuclear, gas, oil, hydro and purchased power. The generation facilities of our electric utility fleet are located in Virginia, West Virginia and North Carolina. The generation facilities of our merchant fleet are located in Connecticut, Illinois, Indiana, Massachusetts, Ohio, Pennsylvania, Rhode Island, West Virginia and Wisconsin.

Dominion Generation's earnings primarily result from the generation and sale of electricity. Due to 2004 deregulation legislation, revenues for serving Virginia jurisdictional retail load are based on capped rates through 2010 and fuel costs for the utility fleet, including power purchases, are subject to fixed rate recovery provisions until July 1, 2007, at which time fuel rates will be adjusted annually as discussed in *Status of Electric Restructuring in Virginia* under *Future Issues and Other Matters*. Changes in our utility operating costs, particularly with respect to fuel and purchased power, relative to costs used to establish capped rates, will impact our earnings.

Variability in earnings provided by the merchant fleet relates to changes in market-based prices received for electricity and the demand for electricity, which is primarily weather driven. We manage price volatility by hedging a substantial portion of our expected sales. Variability also results from changes in the cost of fuel consumed, labor and benefits and the timing, duration and costs of scheduled and unscheduled outages.

In December 2006, we reached an agreement with an entity jointly owned by Tenaska Power Fund, L.P. and Warburg Pincus LLC to sell three of our natural gas-fired merchant generation peaking facilities (Peaker facilities). Peaking facilities are used during times of high electricity demand, generally in the summer months. The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary's, West Virginia.

The sale is expected to result in proceeds of approximately \$256 million and should close in the first quarter of 2007, pending regulatory approval by FERC. We have obtained approval from the Federal Trade Commission. No state regulatory approvals are required.

We offered the facilities for sale following a review of our portfolio of assets. We have decided not to sell a fourth merchant generation facility, State Line, a 515 Mw coal-fired facility in Hammond, Indiana.

Dominion E&P includes our gas and oil exploration, development and production business. 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, West Texas, Mid-Continent, the Rockies and Appalachia, as well as the Western Canadian Sedimentary Basin.

Dominion E&P generates income from the sale of natural gas and oil we produce from our reserves. Variability in earnings relates primarily to changes in commodity prices, which are market-based, and production volumes, which are impacted by numerous factors including drilling success, timing of development projects and external factors such as storm-related damage caused by hurricanes. We attempt to manage commodity price volatility by hedging a substantial portion of our expected production. These hedging activities may require cash deposits to satisfy collateral requirements.

In November 2006, we announced our decision to pursue the sale of all of our oil and natural gas E&P operations and assets, with the exception of those located in the Appalachian Basin. As of December 31, 2006, our natural gas and oil assets—excluding the Appalachian Basin—included about 5.5 trillion cubic feet of proved reserves. The Appalachian assets that we would retain constitute approximately 15% of our total reserves as of December 31, 2006.

Corporate includes our corporate, service company and other operations (including unallocated debt), corporate-wide commodity risk management services, the remaining assets of DCI, which are in the process of being divested, the net impact of our discontinued telecommunications operations that were sold in May 2004 and the net impact of the discontinued operations of the Peaker facilities. In addition, Corporate includes specific items attributable to our operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments.

Outlook

A sale of substantially all of our E&P business would allow us to focus on growing our electric generating and energy distribution, transmission and storage businesses and realign our operations and risk profile more closely with our peer investment group of utilities. If a sale is completed, we would use the net cash proceeds to reduce debt and maintain or improve our existing credit ratings. We would also expect to repurchase shares of our common stock and/or acquire select assets to complement our remaining businesses. By redeploying net cash proceeds to debt reduction, stock buybacks and expansion of our remaining businesses, we believe that shareholders would see solid, reliable growth from a complementary set of assets. Our objective is to grow consolidated earnings at a long-term average annual rate of 4 to 6 percent following any E&P sale. Closing of any sale or sales is targeted for mid-2007.

While a sale would likely dilute consolidated earnings per share in the short term, we believe a sale will result in more stable and predictable earnings that are less sensitive to changes in commodity prices, and could result in an increased dividend. Our Board of Directors will address the issue of a possible change in the dividend policy following a sale. In total, we believe that our strategic repositioning, once complete, will provide the necessary platform to enhance shareholder value.

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

ACCOUNTING MATTERS

Critical Accounting Policies and Estimates

We have identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to our financial condition or results of operations under different conditions or using different assumptions. We have discussed the development, selection and disclosure of each of these policies with the Audit Committee of our Board of Directors.

ACCOUNTING FOR DERIVATIVE CONTRACTS AT FAIR VALUE

We use derivative contracts such as futures, swaps, forwards, options and financial transmission rights to buy and sell energy-related commodities and to manage our commodity and financial markets risks. Derivative contracts, with certain exceptions, are subject to fair value accounting and are reported in our Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies.

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 use of statistical methods. 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. 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 under 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 a contract's estimated fair value.

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

USE OF ESTIMATES IN GOODWILL IMPAIRMENT TESTING

As of December 31, 2006, we reported \$4.3 billion of goodwill in our Consolidated Balance Sheet, a significant portion of which resulted from the acquisition of Consolidated Natural Gas Company (CNG) in 2000. Substantially all of this goodwill is allocated to our Generation, Transmission, Delivery and E&P reporting units. In April of each year, we test our goodwill for potential impairment, and perform additional tests more frequently if impairment indicators are present. The 2006, 2005 and 2004 annual tests did not result in the recognition of any goodwill impairment, as the estimated fair values of our reporting units exceeded their respective carrying amounts.

We estimate the fair value of our reporting units by using a combination of discounted cash flow analyses, based on our internal five-year strategic plan, and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. These calculations are dependent on subjective factors such as our estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in our estimates of future cash flows, could result in a future impairment of goodwill. Although we have consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent annual test had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

USE OF ESTIMATES IN LONG-LIVED ASSET IMPAIRMENT TESTING

Impairment testing for an individual or group of long-lived assets or for intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. Performing an impairment test on long-lived assets involves judgment in areas such as identifying circumstances that indicate an impairment may exist; identifying and grouping affected assets; and developing the undiscounted and discounted estimated future cash flows (used to estimate fair

value in the absence of market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing and the selection of an appropriate discount rate. Although our cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors such as the expected use of the asset, including future production and sales levels, and expected fluctuations of prices of commodities sold and consumed.

In conjunction with the results of a review of our portfolio of assets, the Peaker facilities, with a combined carrying amount of \$504 million, were marketed for sale in the third quarter of 2006. An impairment analysis performed in the third quarter of 2006 indicated that the carrying amount of each of the Peaker facilities was recoverable as the expected undiscounted cash flows, probability weighted to reflect both continued use and possible sale scenarios, exceeded the carrying amount. In December 2006, we reached an agreement to sell the Peaker facilities and accordingly, we reduced their carrying amounts to fair value less cost to sell and classified them as held for sale in our Consolidated Balance Sheet. Also in the fourth quarter of 2006, in conjunction with the review of our assets, a decision was made to no longer pursue the development of a gas transmission pipeline project with capitalized construction costs of \$28 million. The pipeline project was previously tested for impairment during 2005. The results of our analysis in 2005 indicated that this asset was not impaired. Impairment charges of \$280 million (\$181 million after-tax) were recorded in December 2006 related to the Peaker facilities and the transmission pipeline project.

Also in 2006, a natural gas-fired merchant generation facility project, with a carrying amount of \$460 million, was tested for impairment. The results of our analysis indicated that this carrying amount, as well as the estimated cost to complete, were recoverable.

In 2005, we tested a group of gas and steam electric turbines held for future development with a carrying amount of \$187 million for impairment. The results of our analysis indicated that this carrying amount was recoverable. In 2004, we did not test any significant long-lived assets or asset groups for impairment as no circumstances arose that indicated an impairment may exist.

ASSET RETIREMENT OBLIGATIONS

We recognize liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These asset retirement obligations (AROs) are recognized at fair value as incurred, and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, we estimate the fair value of our AROs using present value techniques, in which we make various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. AROs currently reported in our Consolidated Balance Sheets were measured during a period of historically low interest rates. The impact on measurements of new AROs or remeasurements of existing AROs, using different rates in the future, may be significant. When we revise any assumptions used to calculate the fair value of existing AROs, we adjust the carrying amount of both the ARO liability and the related long-lived asset. We

accrete the ARO liability to reflect the passage of time. In 2006, 2005 and 2004, we recognized \$109 million, \$102 million and \$91 million, respectively, of accretion, and expect to incur \$82 million in 2007.

A significant portion of our AROs relates to the future decommissioning of our nuclear facilities. At December 31, 2006, nuclear decommissioning AROs, which are reported in the Dominion Generation segment, totaled \$1.4 billion, representing approximately 73% of our total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with our nuclear decommissioning obligations.

We obtain from third-party specialists periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our utility and merchant nuclear plants. We obtained updated cost studies for all of our nuclear plants in 2006 which generally reflected increases in base year costs. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, our cost estimates include cost escalation rates that are applied to the base year costs. The selection of these cost escalation rates is dependent on subjective factors which we consider to be a critical assumption.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities, for each of our nuclear facilities. In 2006, we lowered the cost escalation rate assumptions used in the ARO calculation by 0.72% due to projected reductions in both general and decommissioning specific inflation rates, resulting in a \$481 million decrease in our nuclear decommissioning AROs.

EMPLOYEE BENEFIT PLANS

We sponsor noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected rate of return on plan assets, discount rates applied to benefit obligations and the anticipated rate of increase in health care costs and participant compensation, also have a significant impact on employee benefit costs. The impact on pension and other postretirement benefit plan obligations associated with changes in these factors is generally recognized in our Consolidated Statements of Income over the remaining average service period of plan participants rather than immediately.

The expected long-term rates of return on plan assets, discount rates and medical cost trend rates are critical assumptions. 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
- Investment allocation of plan assets. Effective September 1, 2006, the strategic target asset allocation for our pension fund is 34% U.S. equity securities, 12% non-U.S. equity securities, 22% debt securities, 7% real estate and 25% other, such as private equity investments. Prior to September 1, 2006, the strategic target asset allocation for our pension fund was 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.

Assisted by an independent actuary, we develop assumptions, which are then compared to the forecasts of other independent investment advisors to ensure reasonableness. An internal committee selects the final assumptions. We calculated our pension cost using an expected return on plan assets assumption of 8.75% for 2006, 2005 and 2004. We calculated our 2006 and 2005 other postretirement benefit cost using an expected return on plan assets assumption of 8.00% compared to 7.79% for 2004. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

We determine discount rates 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. The discount rates used to calculate 2006 pension cost and other postretirement benefit cost were 5.60% and 5.50%, respectively, compared to the 6.00% and 6.25% discount rates used to calculate 2005 and 2004 pension and other postretirement benefit costs, respectively. Lower long-term bond yields were the primary reason for the decline in the discount rate from 2005 to 2006. We selected discount rates of 6.20% and 6.10% for determining our December 31, 2006 projected pension and postretirement benefit obligations, respectively.

We establish the medical cost trend rate assumption based on analyses performed by a third-party actuarial firm of various factors including the specific provisions of our medical plans, actual cost trends experienced and projected, and demographics of plan participants. Our medical cost trend rate assumption as of December 31, 2006 is 9.00% and is expected to gradually decrease to 5.00% in later years.

The following table illustrates the effect on cost of changing the critical actuarial assumptions previously discussed, while holding all other assumptions constant:

			Increase in Net Periodic Cost
Actuarial Assumption	Change in Assumption	Pension Benefits	Other Postretirement Benefits
(millions, except percentages)			
Discount rate	(0.25)%	\$13	\$ 3
Rate of return on plan assets	(0.25)%	11	2
Healthcare cost trend rate	1%	N/A	30

In addition to the effects on cost, a 0.25% decrease in the discount rate would increase our projected pension benefit obligation by \$122 million and would increase our accumulated postretirement benefit obligation by \$38 million at December 31, 2006.

ACCOUNTING FOR REGULATED OPERATIONS

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

We evaluate whether or not recovery of our regulatory assets through future rates is probable and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. In 2006, \$166 million of our regulatory assets were written off as a result of the pending sale of Peoples and Hope since the recovery of those assets is no longer probable. We currently believe the recovery of our remaining regulatory assets is probable. See Notes 2 and 14 to our Consolidated Financial Statements.

ACCOUNTING FOR GAS AND OIL OPERATIONS

We follow the full cost method of accounting for gas and oil E&P 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 and subsequently depleted using the units-of-production method. The depletable base of costs 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. Capitalized costs in the depletable base are subject to a ceiling test prescribed by the SEC. The test limits capitalized amounts to a ceiling—the present value of estimated future net revenues to be derived from the production of proved gas and oil reserves, assuming period-end pricing adjusted for any cash flow hedges in place. We perform the ceiling test quarterly, on a country-by-country basis, and would recognize asset impairments to the extent that total capitalized costs exceed the ceiling. 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.

Our estimate of proved reserves requires a large degree of judgment and is dependent on factors such as historical data, engineering estimates of proved reserve quantities, estimates of the amount and timing of future expenditures to develop the proved reserves, and estimates of future production from the proved reserves. Our estimated proved reserves as of December 31, 2006 are based upon studies for each of our properties prepared by our

staff engineers and audited by Ryder Scott Company, L.P. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines. Given the volatility of natural gas and oil prices, it is possible that our estimate of discounted future net cash flows from proved natural gas and oil reserves that is used to calculate the ceiling could materially change in the near-term.

The process to estimate reserves is imprecise, and estimates are subject to revision. If there is a significant variance in any of our estimates or assumptions in the future and revisions to the value of our proved reserves are necessary, related depletion expense and the calculation of the ceiling test would be affected and recognition of natural gas and oil property impairments could occur. See Notes 2 and 29 to our Consolidated Financial Statements.

INCOME TAXES

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

Through December 31, 2006, we have established liabilities for tax-related contingencies in accordance with Statement of Financial Accounting Standards (SFAS) No. 5, *Accounting for Contingencies*, and reviewed them in light of changing facts and circumstances. However, as discussed in Note 4 to our Consolidated Financial Statements, effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets.

Other

ACCOUNTING STANDARDS

During 2006, 2005 and 2004, we were required to adopt several new accounting standards, which are discussed in Note 3 to our Consolidated Financial Statements. Our adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* on December 31, 2006 affected the comparability of our Consolidated Balance Sheet at December 31, 2006 to prior periods. Under SFAS No. 158, our

Consolidated Balance Sheet now reflects the overfunded or underfunded status of our defined benefit plans as an asset or a liability, respectively, with previously unrecognized net actuarial gains or losses, prior service costs or credits and transition obligations recognized as a component of either AOCI or regulatory assets or liabilities. See Note 4 to our Consolidated Financial Statements for a discussion of recently issued accounting standards that will be adopted in the future.

DOMINION CLEARINGHOUSE

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 our assets. 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 were redesignated as held for non-trading purposes. Under our derivative income statement classification policy described in Note 2 to our Consolidated Financial Statements, 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 redesignation as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are reported in other operations and maintenance expense. In addition, all physically-settled sales contracts are presented in operating revenue and all physically-settled purchase contracts are presented in operating expense in our Consolidated Statements of Income.

RESULTS OF OPERATIONS

Presented below is a summary of our consolidated results:

Year Ended December 31,	2006	\$ Change	2005	\$ Change	2004
(millions, except EPS)					
Net Income	\$1,380	\$ 347	\$1,033	\$(216)	\$1,249
Diluted earnings per share (EPS)	3.93	0.93	3.00	(0.78)	3.78

Overview

2006 VS. 2005

Net income increased 34% to \$1.4 billion. Favorable drivers included increased gas and oil production, higher realized prices from our merchant generation business, an increased contribution from our nonregulated retail energy marketing operations, higher business interruption insurance proceeds received in 2006 than in 2005 and the absence of losses incurred in 2005 due to the discontinuance of hedge accounting for certain gas and oil hedges resulting from hurricane-related interruptions of gas and oil production in the Gulf of Mexico. These favorable drivers were partially offset by an impairment charge related to the Peaker facilities, milder weather in our gas and electric service territories, lower realized gas prices for our E&P operations and a

reduction in gains from sales of emissions allowances held for consumption.

2005 VS. 2004

Our 2005 results were significantly impacted by Hurricanes Katrina and Rita (2005 hurricanes), which struck the Gulf Coast area in late August and late September 2005, respectively. Due to the hurricanes, our production assets in the Gulf of Mexico and, to a lesser extent, southern Louisiana were temporarily shut in. The interruption in gas and oil production resulted in a \$272 million after-tax loss related to the discontinuance of hedge accounting for certain gas and oil hedges. Results were also impacted by delays in production caused by damage to third-party downstream infrastructure.

Our 2005 results were also negatively impacted by increased fuel and purchased power expenses incurred by our electric utility operations primarily as a result of higher commodity prices. These negatives were partially offset by higher realized gas and oil prices for our E&P operations, gains on the sale of emissions allowances and a higher contribution from merchant generation operations, primarily reflecting the benefit of two acquisitions during 2005. In January 2005, we completed the acquisition of three fossil-fired power stations with generating capacity of more than 2,700 Mw (Dominion New England) and in July 2005, we completed the acquisition of the 556 Mw Kewaunee nuclear power station (Kewaunee).

Analysis of Consolidated Operations

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

Year ended December 31,	2006	\$ Change	2005	\$ Change	2004
(millions)					
Operating Revenue	\$16,482	\$(1,489)	\$17,971	\$4,042	\$13,929
Operating Expenses					
Electric fuel and energy purchases	3,236	(1,434)	4,670	2,544	2,126
Purchased electric capacity	481	(23)	504	(83)	587
Purchased gas	2,937	(1,004)	3,941	1,014	2,927
Other energy-related commodity purchases	1,022	(369)	1,391	402	989
Other operations and maintenance	3,280	226	3,054	299	2,755
Depreciation, depletion and amortization	1,606	209	1,397	108	1,289
Other taxes	575	(6)	581	62	519
Other income	174	6	168	1	167
Interest and related charges	1,030	64	966	40	926
Income tax expense	920	332	588	(117)	705
Loss from discontinued operations, net of tax	(183)	(175)	(8)	16	(24)

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

2006 VS. 2005

Operating Revenue decreased 8% to \$16.5 billion, primarily reflecting:

- A \$1.0 billion decrease primarily attributable to lower volumes associated with requirements-based power sales contracts that we are exiting. The effect of this decrease is more than offset by a corresponding decrease in *Electric fuel and energy purchases expense*;
- An \$844 million decrease in our producer services business consisting of a decrease in both volumes and prices associated with gas aggregation, partially offset by favorable price changes related to gas marketing activities. The effect of this decrease is partially offset by a corresponding decrease in *Purchased gas expense*;
- A \$367 million decrease from regulated gas distribution operations, primarily reflecting a \$219 million decrease resulting from the loss of customers to Energy Choice programs and a \$270 million decrease associated with milder weather and variations in rates resulting from changes in customer usage patterns, sales mix and other factors, partially offset by a \$122 million increase related to the recovery of higher gas prices. The effect of this net decrease was partially offset by a corresponding decrease in *Purchased gas expense*;
- A \$308 million decrease in nonutility coal sales, primarily resulting from decreased volumes. This decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*;
- A \$178 million decrease in sales of emissions allowances purchased for resale, reflecting lower prices (\$115 million) and lower overall sales volume (\$63 million). The effect of this decrease was largely offset by a corresponding decrease in *Other energy-related commodity purchases expense*; and
- A \$93 million decrease in revenue from sales of gas purchased by E&P operations to facilitate gas transportation and other contracts, primarily due to the impact of netting sales and purchases of gas under buy/sell arrangements associated with the implementation of Emerging Issues Task Force (EITF) Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. These decreases were partially offset by:
 - A \$313 million increase from our merchant generation business, primarily reflecting higher revenue for nuclear operations as a result of higher realized prices and new business from the addition of Kewaunee, which was acquired in July 2005. This increase was partially offset by lower sales volume for fossil plants driven largely by comparably milder weather and lower prices;
 - A \$235 million increase associated with hedging activities for our merchant generation assets. The effect of this increase is offset by a corresponding increase in *Other operations and maintenance expense*;
 - A \$188 million increase in sales of gas and oil production, primarily due to higher volumes (\$397 million), partially offset by lower prices (\$209 million);
 - A \$184 million increase in gas sales by our nonregulated retail energy marketing operations primarily resulting from increased customer counts (\$141 million) and higher contracted sales prices (\$43 million);
 - A \$170 million increase in sales of extracted products, primarily due to increased prices and a contractual change for

a portion of our gas production processed by third parties. We now take title to and market the extracted products from this gas;

- An increase of \$95 million resulting from higher business interruption insurance revenue received in 2006 related to the 2005 hurricanes (\$274 million) versus business interruption revenue received in 2005 (\$179 million) related to Hurricane Ivan; and
- An \$88 million increase due to a sale of gas inventory by our East Ohio Gas subsidiary related to the implementation of the Standard Service Offer (SSO) pilot program as approved by the Ohio Commission. The SSO was initiated to encourage and assist other suppliers to enter the gas procurement market. By the end of the transition period, we plan to exit the gas merchant function in Ohio and have all customers select an alternate gas supplier. The effect of this increase was offset by a comparable increase in *Purchased gas expense*.

Operating Expenses

Electric fuel and energy purchases expense decreased 31% to \$3.2 billion, primarily reflecting the combined effects of:

- A \$1.2 billion decrease associated with lower volumes associated with requirements-based power sales contracts, as discussed in *Operating Revenue*;
- A \$162 million decrease for our utility generation operations, primarily due to lower commodity prices, including purchased power, and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by an increase in purchased power volumes; and
- A \$104 million decrease from our merchant generation business, due primarily to lower commodity prices and decreased consumption of fossil fuel, reflecting the effects of milder weather on demand, partially offset by higher replacement power costs incurred due to an increase in scheduled outage days.

Purchased gas expense decreased 25% to \$2.9 billion, principally resulting from:

- An \$815 million decrease associated with our producer services business, due to lower volumes and prices;
- A \$192 million decrease related to regulated gas distribution operations, due to a \$252 million decrease associated with milder weather and the migration of additional customers to Energy Choice and a \$222 million decrease due to lower average gas prices, partially offset by a \$282 million increase related to the recovery of gas costs;
- A \$120 million decrease related to E&P operations, as the result of lower volumes and the impact of netting sales and purchases of gas under buy/sell arrangements following the implementation of EITF 04-13, as discussed in *Operating Revenue*; partially offset by
- A \$139 million increase associated with nonregulated retail energy marketing operations, primarily due to increased volumes.

Other energy-related commodity purchases expense decreased 27% to \$1.0 billion, primarily attributable to the following factors, all of which are discussed in *Operating Revenue*:

- A \$237 million decrease in the cost of coal purchased for resale; and
- A \$175 million decrease in emissions allowances purchased for resale; partially offset by

- A \$47 million increase related to purchases of oil by E&P operations, reflecting higher market prices (\$63 million), partially offset by lower volumes (\$16 million) of oil purchases under buy/sell arrangements.

Other operations and maintenance expense increased 7% to \$3.3 billion, resulting from:

- A \$235 million increase primarily related to hedging activities associated with our generation assets. The effect of this increase is offset by a corresponding increase in *Operating Revenue*;
 - A \$166 million charge from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope;
 - A \$105 million increase attributable to higher production handling, transportation and operating costs related to E&P operations;
 - A \$97 million increase resulting primarily from higher salaries, wages and benefits expenses;
 - \$91 million of impairment charges related to DCI investments;
 - A \$79 million increase resulting from Kewaunee, which was acquired in July 2005;
 - A \$65 million decrease in gains from the sale of emissions allowances held for consumption;
 - A \$60 million charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities;
 - A \$41 million reduction in proceeds related to financial transmission rights (FTRs) granted by PJM to our utility generation operations. These FTRs are used to offset congestion costs associated with PJM spot market activity, which are included in *Electric fuel and energy purchases expense*;
 - A \$35 million increase in generation-related outage costs primarily due to an increase in the number of scheduled outages;
 - A \$29 million increase related to major storm damage and service restoration costs associated with our distribution operations, primarily resulting from tropical storm Ernesto in September 2006;
 - A \$27 million charge resulting from the cancellation of a pipeline project;
- These increases were partially offset by:
- A \$62 million benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes;
 - A \$96 million decrease in hedge ineffectiveness expense associated with our E&P operations, primarily due to a decrease in the fair value differential between the delivery location and commodity specifications of derivative contracts held by us as compared to our forecasted gas and oil sales and the increased use of basis swaps;
 - A benefit resulting from the absence of the following items recognized in 2005:
 - A \$423 million 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 the 2005 hurricanes;
 - A \$77 million charge resulting from the termination of a long-term power purchase agreement;

- A \$59 million loss related to the discontinuance of hedge accounting for certain oil derivatives primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those derivatives; and
- A \$51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation; partially offset by
- A \$24 million net benefit resulting from the establishment of certain regulatory assets and liabilities in connection with the settlement of a North Carolina rate case in the first quarter of 2005.

Depreciation, depletion and amortization expense (DD&A) increased 15% to \$1.6 billion, largely due to the impact of increased gas and oil production, as well as higher E&P finding and development costs.

Interest expense increased 7% to \$1.0 billion principally reflecting the impact of additional borrowings and higher interest rates on variable rate debt.

Loss from discontinued operations increased to \$183 million primarily reflecting a \$164 million after-tax impairment charge related to the pending sale of the Peaker facilities, whose operating losses were reclassified to discontinued operations in December 2006.

2005 VS. 2004

Operating Revenue increased 29% to \$18.0 billion, primarily reflecting:

- A \$1.1 billion increase in sales from our merchant generation operations, primarily attributable to the addition of Dominion New England and Kewaunee and a full year of commercial operations at our Fairless Energy power station (Fairless), which began operating in June 2004;
- A \$730 million increase related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005. These contracts were previously held for trading purposes as discussed in Note 28 to our Consolidated Financial Statements. The impact of this change in classification was offset by similar changes in *Other operations and maintenance expense* and *Electric fuel and energy purchases expense*;
- A \$588 million increase from gas aggregation activities and nonregulated retail energy marketing operations primarily due to higher gas prices. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- A \$363 million increase from our regulated electric utility operations reflecting a \$153 million increase in sales to wholesale customers, a \$99 million increase due to the impact of a comparatively higher fuel rate for non-Virginia jurisdictional customers, a \$77 million increase primarily due to the impact of favorable weather on customer usage and a \$59 million increase from customer growth associated with new customer connections, partially offset by a \$25 million decrease due to variations in seasonal rate premiums and discounts. The increase resulting from a comparatively higher fuel rate was more than offset by an increase in *Electric fuel and energy purchases expense*; and
- A \$341 million increase from regulated gas distribution operations primarily related to the recovery of higher gas prices.

The effect of this increase was offset by a comparable increase in *Purchased gas expense*;

- A \$276 million increase in nonutility coal sales resulting from higher coal prices (\$171 million) and increased sales volumes (\$105 million). This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*;
- A \$110 million increase due to higher natural gas prices related to market-based services for the optimization of transportation and storage assets by our E&P operations, partially offset by the effect of unfavorable price changes on unsettled contracts. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- A \$110 million increase in sales of gas purchased by E&P operations to facilitate gas transportation and satisfy other agreements. This increase was largely offset by a corresponding increase in *Purchased gas expense*;
- An \$87 million increase in sales of purchased oil by E&P operations. This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*;
- A \$37 million increase in sales of emissions allowances held for resale primarily due to higher prices. This increase was more than offset by a corresponding increase in *Other energy-related commodity purchases expense*.

Operating Expenses

Electric fuel and energy purchases expense increased 120% to \$4.7 billion, primarily reflecting the combined effects of:

- A \$1.2 billion increase related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005, which were previously held for trading purposes as discussed in *Operating Revenue*;
- A \$796 million increase related to utility operations primarily resulting from higher commodity prices including purchased power; and
- A \$556 million increase due to the addition of Dominion New England and Kewaunee and a full year of commercial operations at Fairless.

Purchased electric capacity expense decreased 14% to \$504 million, as a result of the termination of several long-term power purchase agreements in connection with the purchase of the related generating facilities in 2005 and 2004.

Purchased gas expense increased 35% to \$3.9 billion, principally resulting from the following items which are discussed in *Operating Revenue*:

- A \$522 million increase associated with gas aggregation activities and nonregulated retail energy marketing operations;
- A \$305 million increase associated with regulated gas distribution operations; and
- A \$124 million increase related to E&P operations.

Other energy related-commodity purchases expense increased 41% to \$1.4 billion, primarily reflecting the following items which are discussed in *Operating Revenue*:

- A \$263 million increase in the cost of coal purchased for resale;
- A \$91 million increase related to purchases of oil by E&P operations; and

- A \$47 million increase in emissions allowances purchased for resale.

Other operations and maintenance expense increased 11% to \$3.1 billion, resulting from:

- A \$423 million 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 the 2005 hurricanes;
 - A \$361 million increase due to the addition of Dominion New England and Kewaunee and a full year of commercial operations at Fairless;
 - A \$193 million increase in salaries and benefits, due to higher incentive-based compensation (\$106 million), wages (\$43 million) and pension and medical benefits (\$44 million);
 - A \$77 million charge resulting from the termination of a long-term power purchase agreement;
 - A \$75 million increase in hedge ineffectiveness expense associated with E&P operations, primarily due to an increase in the fair value differential between the delivery location and commodity specifications of our derivative contracts and the delivery location and commodity specifications of our forecasted gas and oil sales;
 - A \$59 million loss related to the discontinuance of hedge accounting in March 2005 for certain oil hedges primarily resulting from a delay in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges;
 - A \$51 million charge related to credit exposure associated with the bankruptcy of Calpine Corporation;
 - A \$35 million charge related to our investment in and planned divestiture of DCI assets;
- These increases were partially offset by the following:
- A \$344 million decrease related to the designation of certain commodity derivative contracts as held for non-trading purposes effective January 1, 2005, which were previously held for trading purposes as discussed in *Operating Revenue*;
 - A \$186 million benefit related to FTRs;
 - A \$139 million gain resulting from the sale of emissions allowances held for consumption;
 - A \$24 million net benefit resulting from the establishment of certain regulatory assets and liabilities in connection with the settlement of a North Carolina rate case in the first quarter of 2005; and
 - The net impact of the following items recognized in 2004:
 - A \$184 million charge related to the sale of our interest in a long-term power tolling contract in connection with our exit from certain energy trading activities;
 - A \$96 million 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 during the third quarter;
 - A \$72 million charge associated with the impairment of retained interests from mortgage securitizations and venture capital and other equity investments held by DCI; and
 - A \$71 million net charge resulting from the termination of certain long-term power purchase agreements; partially offset by

- A \$120 million benefit due to favorable changes in the fair value of certain oil options related to E&P operations.

Depreciation, depletion and amortization expense increased 8% to \$1.4 billion, largely due to incremental depreciation and amortization expense resulting from our acquisition of the Dominion New England power plants and other property additions.

Other taxes increased 12% to \$581 million, primarily due to higher property taxes resulting from the Dominion New England power plants and higher severance taxes associated with increased commodity prices.

Loss from discontinued operations reflects charges related to the Peaker facilities, whose operating losses were reclassified to discontinued operations as a result of their pending sale.

SEGMENT RESULTS OF OPERATIONS

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Presented below is a summary of contributions by our operating segments to net income:

Year Ended December 31,	2006		2005		2004	
	Net Income	Diluted EPS	Net Income	Diluted EPS	Net Income	Diluted EPS
(millions, except EPS)						
Dominion Delivery	\$ 438	\$ 1.25	\$ 448	\$ 1.30	\$ 466	\$ 1.41
Dominion Energy	360	1.02	319	0.93	190	0.57
Dominion Generation	537	1.53	416	1.20	533	1.61
Dominion E&P	680	1.93	565	1.64	595	1.80
Primary operating segments	2,015	5.73	1,748	5.07	1,784	5.39
Corporate	(635)	(1.80)	(715)	(2.07)	(535)	(1.61)
Consolidated	\$1,380	\$ 3.93	\$1,033	\$ 3.00	\$1,249	\$ 3.78

Dominion Delivery

Presented below are operating statistics related to Dominion Delivery's operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Electricity delivered (million mwhrs) ⁽¹⁾	79.8	(2)%	81.4	4%	78.0
Degree days (electric service area):					
Cooling ⁽²⁾	1,557	(9)	1,707	8	1,585
Heating ⁽³⁾	3,178	(16)	3,784	3	3,682
Average electric delivery customer accounts ⁽⁴⁾	2,327	2	2,286	2	2,244
Gas throughput (bcf):					
Gas sales	94	(28)	131	3	127
Gas transportation	240	—	241	(1)	244
Heating degree days (gas service area) ⁽³⁾	5,190	(12)	5,899	3	5,716
Average gas delivery customer accounts ⁽⁴⁾ :					
Gas sales	858	(17)	1,030	3	996
Gas transportation	830	26	661	(5)	693
Average nonregulated retail energy marketing customer accounts ⁽⁴⁾	1,354	17	1,162	(13)	1,341

mwhrs = megawatt hours
bcf = billion cubic feet

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

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

2006 VS. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	\$(29)	\$(0.08)
Customer growth	11	0.03
Other ⁽¹⁾	15	0.04
Regulated gas sales—weather	(26)	(0.07)
Major storm damage and service restoration	(18)	(0.05)
Interest expense ⁽²⁾	(11)	(0.03)
Other margins—gas ⁽³⁾	(10)	(0.03)
2005 North Carolina rate case settlement	(6)	(0.02)
Nonregulated retail energy marketing operations ⁽⁴⁾	57	0.17
Other	7	0.02
Share dilution	—	(0.03)
Change in net income contribution	\$(10)	\$(0.05)

- (1) Attributable to rate variations from changes in customer usage patterns and sales mix, and other factors.
- (2) Principally reflects additional intercompany borrowings and higher interest rates on those borrowings.
- (3) Largely reflects reduced customer usage at our regulated gas distribution operations, due in part to price sensitivity.
- (4) Largely reflects higher electric and gas margins due to higher rates, increased gas customers and lower commodity costs.

2005 VS. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Interest expense ⁽¹⁾	\$(25)	\$(0.08)
Salaries, wages and benefits expense	(14)	(0.04)
Depreciation expense	(10)	(0.03)
Bad debt expense ⁽²⁾	(7)	(0.02)
Regulated electric sales:		
Weather	14	0.04
Customer growth	11	0.03
Regulated gas sales—weather	8	0.02
2005 North Carolina rate case settlement	6	0.02
Other	(1)	—
Share dilution	—	(0.05)
Change in net income contribution	\$(18)	\$(0.11)

- (1) Represents the impact of additional long-term affiliate borrowings and variable rate debt, higher interest rates on affiliate borrowings and prepayment penalties resulting from the early redemption of debt.
- (2) Higher bad debt expense primarily reflects the absence of a 2004 reduction in reserves.

Dominion Energy

Presented below are operating statistics related to Dominion Energy's operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Gas transportation throughput (bcf)	650	(18)%	794	13%	704

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

2006 VS. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Gas transmission:		
Other margins ⁽¹⁾	\$ 39	\$ 0.11
Rate settlement ⁽²⁾	(13)	(0.04)
Producer services ⁽³⁾	23	0.06
Other	(8)	(0.02)
Share dilution	—	(0.02)
Change in net income contribution	\$ 41	\$ 0.09

- (1) Higher margins primarily from extracted products and short-term transportation and storage opportunities.
- (2) Represents lower natural gas transportation and storage revenue as a result of a rate settlement between Dominion Transmission, Inc. (DTI) and its customers, effective July 1, 2005.
- (3) Higher income resulting from the impact of favorable price changes related to price risk management and gas marketing activities associated with certain transportation and storage contracts.

2005 VS. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Producer services ⁽¹⁾	\$119	\$ 0.36
Economic hedges ⁽²⁾	22	0.07
Cove Point ⁽³⁾	13	0.04
Gas transmission rate settlement	(17)	(0.05)
Salaries, wages and benefits expense	(11)	(0.03)
Other	3	0.01
Share dilution	—	(0.04)
Change in net income contribution	\$129	\$ 0.36

- (1) Reflects the impact of losses in the prior year related to certain energy trading activities that were exited in December 2004 and higher contributions from market-based gas trading, storage, transportation and aggregation activities.
- (2) Represents the impact of price movements in 2004 associated with a portfolio of financial derivative instruments used to manage price risk associated with a portion of our anticipated sales of 2004 natural gas production that had not been considered in the hedging activities of the Dominion E&P segment. In 2005, we did not enter into similar economic hedging transactions.
- (3) Reflects the addition of a fifth storage tank in December 2004 and increased pipeline capacity.

Dominion Generation

Presented below are operating statistics related to Dominion Generation's operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Electricity supplied (million mwhrs):					
Utility	79.7	(2)%	81.4	4%	78.0
Merchant ⁽¹⁾	41.7	—	41.5	43	29.1
Degree days (electric utility service area):					
Cooling	1,557	(9)	1,707	8	1,585
Heating	3,178	(16)	3,784	3	3,682

- (1) Includes electricity supplied by the Peaker facilities whose results were reclassified to discontinued operations in December 2006 due to their pending sale.

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

2006 VS. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Merchant generation margin ⁽¹⁾	\$215	\$ 0.63
Unrecovered Virginia fuel expenses	40	0.12
Regulated electric sales:		
Customer growth	24	0.07
Weather	(64)	(0.18)
Other ⁽²⁾	17	0.05
Sales of emissions allowances	(40)	(0.12)
Energy supply margin ⁽³⁾	(27)	(0.08)
Outage costs ⁽⁴⁾	(20)	(0.06)
Salaries, wages and benefits expense	(13)	(0.04)
2005 North Carolina rate case settlement	(10)	(0.03)
Other	(1)	—
Share dilution	—	(0.03)
Change in net income contribution	\$121	\$ 0.33

- (1) Primarily reflects higher realized prices.
- (2) Primarily attributable to rate variations from changes in customer usage patterns and sales mix, and other factors.
- (3) Primarily reflects a reduced benefit from FTRs in excess of congestion costs at our utility operations.
- (4) Primarily due to an increase in the duration of scheduled outage days for our electric utility and certain merchant fossil plants.

2005 VS. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Unrecovered Virginia fuel expenses	\$(280)	\$(0.85)
Energy marketing and risk management activities ⁽¹⁾	(50)	(0.15)
Interest and other financing expense ⁽²⁾	(44)	(0.13)
Salaries, wages and benefits expense	(36)	(0.11)
Merchant generation margin ⁽³⁾	102	0.31
Sales of emissions allowances	63	0.19
Energy supply margin ⁽⁴⁾	40	0.12
Regulated electric sales:		
Weather	39	0.12
Customer growth	24	0.07
Purchased electric capacity expense	37	0.11
2005 North Carolina rate case settlement	10	0.03
Other	(22)	(0.07)
Share dilution	—	(0.05)
Change in net income contribution	\$(117)	\$(0.41)

- (1) Reflects lower gains in 2005 from coal trading and marketing activities and losses related to price risk management activities and legacy power transactions.
- (2) Represents higher interest rates on affiliate borrowings and variable rate debt, prepayment penalties resulting from the early redemption of debt and the lease financing of Fairless.
- (3) Primarily represents contributions from Dominion New England and Kewanee, partially offset by a lower contribution from the Millstone power station due to an additional scheduled outage in 2005.
- (4) Higher energy supply margins reflect a benefit from FTRs in excess of congestion costs at our utility operations.

Dominion E&P

Presented below are operating statistics related to Dominion E&P's operations:

Year Ended December 31,	2006	% Change	2005	% Change	2004
Gas production (bcf)	308	10%	280	(17)%	337
Oil production (million bbls)	24.7	61	15.3	13	13.6
Average realized prices without hedging results:					
Gas (per mcf) ⁽¹⁾	\$ 6.63	(17)	\$ 7.98	39	\$ 5.74
Oil (per bbl)	54.66	10	49.54	40	35.49
Average realized prices with hedging results ⁽²⁾ :					
Gas (per mcf) ⁽¹⁾	4.29	(9)	4.73	16	4.08
Oil (per bbl)	33.39	11	30.21	20	25.11
DD&A (per mcfe)	1.71	16	1.47	13	1.30
Average production (lifting) cost (per mcfe) ⁽³⁾	1.19	2	1.17	27	0.92

bbl = barrel

mcf = thousand cubic feet

mcfe = thousand cubic feet equivalent

- (1) Excludes \$262 million, \$323 million and \$223 million of revenue recognized in 2006, 2005 and 2004, respectively, under the volumetric production payment (VPP) agreements described in Note 12 to our Consolidated Financial Statements.
- (2) Excludes the effects of the economic hedges discussed under *Dominion Energy*.
- (3) The inclusion of volumes produced and delivered under the VPP agreements would have resulted in lifting costs of \$1.06, \$1.00 and \$0.83 for 2006, 2005 and 2004, respectively.

Presented below, on an after-tax basis, are the key factors impacting Dominion E&P's net income contribution:

2006 VS. 2005

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Gas and oil—production ⁽¹⁾	\$ 406	\$ 1.18
Business interruption insurance	62	0.18
Operations and maintenance ⁽²⁾	40	0.11
Gas and oil—prices	(208)	(0.60)
DD&A	(162)	(0.47)
Interest expense ⁽³⁾	(30)	(0.09)
Other	7	0.02
Share dilution	—	(0.04)
Change in net income contribution	\$ 115	\$ 0.29

- (1) Represents an increase primarily in Gulf of Mexico deepwater and shelf gas and oil production and Rocky Mountain gas production.
- (2) Primarily reflects the impact of mark-to-market gains associated with gas hedges that were de-designated following the 2005 hurricanes, partially offset by increased production costs and salaries, wages and benefits expense.
- (3) Primarily reflects additional intercompany borrowings and higher interest rates on those borrowings.

2005 VS. 2004

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Operations and maintenance ⁽¹⁾	\$(134)	\$(0.41)
Gas and oil—production ⁽²⁾	(111)	(0.34)
Interest expense ⁽³⁾	(25)	(0.08)
Gas and oil—prices	185	0.56
Business interruption insurance—Hurricane Ivan	50	0.15
Other	5	0.02
Share dilution	—	(0.06)
Change in net income contribution	\$ (30)	\$(0.16)

- (1) Reflects the absence of a 2004 benefit from favorable changes in the fair value of certain oil options, an increase in hedge ineffectiveness expense in 2005 and the discontinuance of hedge accounting for certain oil hedges in March 2005 largely resulting from delays in reaching anticipated production levels in the Gulf of Mexico, and subsequent changes in the fair value of those hedges, partially offset by a benefit reflecting the impact of a decrease in gas and oil prices on hedges that were de-designated following the 2005 hurricanes.
- (2) Reflects interruptions caused by the 2005 hurricanes and the sale of the majority of our natural gas and oil properties in British Columbia, Canada in December 2004.
- (3) Represents the combined impact of an increase in affiliate borrowings and higher interest rates, as well as prepayment penalties resulting from the early redemption of Canadian debt.

Included below are the volumes and weighted average prices associated with hedges in place as of December 31, 2006 by applicable time period:

Year	Natural Gas		Oil	
	Hedged production (bcf)	Average hedge price (per mcf)	Hedged production (million bbls)	Average hedge price (per bbl)
2007	225.2	\$5.90	10.0	\$33.41
2008	174.9	8.23	5.0	49.36
2009	36.6	7.97	0.3	75.36

Corporate

Presented below are the Corporate segment's after-tax results:

	2006	2005	2004
(millions, except EPS amounts)			
Specific items attributable to operating segments	\$ (149)	\$ (505)	\$ (224)
DCI operations	(95)	(22)	(82)
Peaker discontinued operations	(183)	(13)	(9)
Telecommunications operations ⁽¹⁾	—	5	(13)
Other corporate operations	(208)	(180)	(207)
Total net expense	(635)	(715)	(535)
Earnings per share impact	\$(1.80)	\$(2.07)	\$(1.61)

(1) \$5 million and \$(15) million are classified as discontinued operations in 2005 and 2004, respectively.

Specific Items Attributable to Operating Segments

Corporate includes specific items attributable to our operating segments that have been excluded from the profit measures evaluated by management, either in assessing segment performance or in allocating resources among the segments. See Note 28 to our Consolidated Financial Statements for discussion of these items.

DCI Operations

DCI's net loss for 2006 increased \$73 million, primarily due to an \$85 million impairment of a DCI investment during the third quarter of 2006.

DCI recognized a net loss of \$22 million in 2005; a decrease of \$60 million as compared to 2004. The decrease primarily resulted from a reduction in after-tax charges associated with the impairment and divestiture of other DCI investments.

Peaker Discontinued Operations

In 2006, we recognized a \$283 million (\$183 million after-tax) loss from the discontinued operations of the Peaker facilities. The loss from discontinued operations includes:

- \$253 million (\$164 million after-tax) associated with the impairment of the merchant generation facilities; and
- \$30 million (\$19 million after-tax) of operating losses.

As a result of the pending sale, we reclassified 2005 and 2004 after-tax operating losses of \$13 million and \$9 million, respectively, to discontinued operations.

Telecommunications Operations

We sold our telecommunications business in May 2004 to Elantic Telecom, Inc., which subsequently filed for bankruptcy. Due to the resolution of certain contingencies, we recognized an after-tax benefit of \$5 million in 2005 related to the discontinued telecommunications business.

Other Corporate Operations

The net expenses associated with other corporate operations for 2006 increased by \$28 million as compared to 2005, primarily reflecting a \$37 million after-tax charge to eliminate the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts.

The net expenses associated with other corporate operations for 2005 decreased by \$27 million as compared to 2004, primarily reflecting an increase in interest income from affiliate advances and higher income tax benefits. This was partially offset by the

absence of a \$28 million after-tax benefit in 2004 associated with the disposition of CNG International's investment in Australian pipeline assets.

SELECTED INFORMATION—ENERGY TRADING ACTIVITIES

We engage in energy trading, marketing and hedging activities to complement our integrated energy businesses and facilitate our risk management activities. As part of these operations, we enter into contracts for purchases and sales of energy-related commodities, including natural gas, electricity, oil and coal. Settlements of contracts may require physical delivery of the underlying commodity or cash settlement. We also enter into contracts with the objective of benefiting from changes in prices. For example, after entering into a contract to purchase a commodity, we typically enter into a sales contract, or a combination of sales contracts, with quantities and delivery or settlement terms that are identical or very similar to those of the purchase contract. When the purchase and sales contracts are settled either by physical delivery of the underlying commodity or by net cash settlement, we may receive a net cash margin (a realized gain), or may pay a net cash margin (a realized loss). We continually monitor our contract positions, considering location and timing of delivery or settlement for each energy commodity in relation to market price activity.

A summary of the changes in the unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes during 2006 follows:

	Amount
(millions)	
Net unrealized loss at December 31, 2005	\$ (7)
Contracts realized or otherwise settled during the period	(14)
Net unrealized gain at inception of contracts initiated during the period	—
Change in unrealized gains and losses	63
Changes in unrealized gains and losses attributable to changes in valuation techniques	—
Net unrealized gain at December 31, 2006	\$ 42

The balance of net unrealized gains and losses recognized for our energy-related derivative instruments held for trading purposes at December 31, 2006, is summarized in the following table based on the approach used to determine fair value:

	Maturity Based on Contract Settlement or Delivery Date(s)					
Source of Fair Value	Less than 1 year	1-2 years	2-3 years	3-5 years	In excess of 5 years	Total
(millions)						
Actively-quoted ⁽¹⁾	\$42	\$(2)	\$ 1	\$—	\$—	\$41
Other external sources ⁽²⁾	—	1	(4)	3	1	1
Models and other valuation methods	—	—	—	—	—	—
Total	\$42	\$(1)	\$(3)	\$ 3	\$ 1	\$42

(1) Exchange-traded and over-the-counter contracts.

(2) Values based on prices from over-the-counter broker activity and industry services and, where applicable, conventional option pricing models.

LIQUIDITY AND CAPITAL RESOURCES

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

At December 31, 2006, we had \$3.0 billion of unused capacity under our credit facilities. See additional discussion under *Credit Facilities and Short-Term Debt*.

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

	2006	2005	2004
(millions)			
Cash and cash equivalents at beginning of year	\$ 146	\$ 361	\$ 126
Cash flows provided by (used in):			
Operating activities	4,005	2,623	2,770
Investing activities	(3,494)	(3,360)	(1,215)
Financing activities	(515)	522	(1,320)
Net increase (decrease) in cash and cash equivalents	(4)	(215)	235
Cash and cash equivalents at end of year ⁽¹⁾	\$ 142	\$ 146	\$ 361

(1) 2006 amount includes \$4 million of cash classified as held for sale in our Consolidated Balance Sheet.

Operating Cash Flows

In 2006, net cash provided by operating activities increased by \$1.4 billion as compared to 2005. The increase was primarily due to an increase in cash earnings attributable to higher natural gas and oil production, recovery of deferred fuel and purchased gas costs and business interruption insurance proceeds, as well as increased contributions from our merchant generation, non-regulated retail energy marketing and gas transmission businesses. The 2006 increase also reflects favorable changes in working capital, mainly accounts receivable and inventories. We believe that our operations provide a stable source of cash flow sufficient to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. However, our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows which are discussed in *Risk Factors*. The declaration and payment of dividends are subject to the discretion of our Board of Directors and will depend upon our results of operations, financial condition, capital requirements and future prospects.

CREDIT RISK

Our exposure to potential concentrations of credit risk results primarily from our energy marketing and price risk management activities and sales of gas and oil production. Presented below is a summary of our gross credit exposure as of December 31, 2006 for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade ⁽¹⁾	\$ 855	\$28	\$ 827
Non-investment grade ⁽²⁾	57	2	55
No external ratings:			
Internally rated—investment grade ⁽³⁾	280	5	275
Internally rated—non-investment grade ⁽⁴⁾	171	—	171
Total	\$1,363	\$35	\$1,328

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (Standard & Poor's). The five largest counterparty exposures, combined, for this category represented approximately 21% of the total net credit exposure.

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

(3) The five largest counterparty exposures, combined, for this category represented approximately 13% of the total net credit exposure.

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

Investing Cash Flows

Significant cash flows used in investing activities for 2006 included:

- \$2.1 billion of capital expenditures for the purchase and development of gas and oil producing properties, drilling and equipment costs and undeveloped lease acquisitions;
- \$2.0 billion of capital expenditures, including environmental upgrades, routine capital improvements, construction of generation facilities, purchase of nuclear fuel and construction and improvements of gas and electric transmission and distribution assets;
- \$1.1 billion for purchases of securities held as investments in our nuclear decommissioning trusts; and
- \$91 million related to the acquisition of Pablo Energy LLC, which holds producing and other properties in the Texas Panhandle area, net of cash acquired.

Cash flows used in investing activities for 2006 were partially offset by:

- \$1.0 billion of proceeds from the sales of securities held as investments in our nuclear decommissioning trusts;
- \$393 million of proceeds from sales of gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico;
- \$150 million of proceeds received from the sale or disposal of certain assets; and
- \$76 million of proceeds from sales of emissions allowances held for consumption.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by the companies' operations. As discussed in *Credit Ratings*, our ability to borrow funds or issue securities and the return demanded by investors are affected by the issuing company's credit ratings. In addition, the raising of external capital is subject

to certain regulatory approvals, including registration with the SEC and, in the case of Virginia Electric and Power Company (Virginia Power), approval by the Virginia State Corporation Commission (Virginia Commission).

In December 2005, the SEC adopted rules that modify the registration, communications and offering processes under the Securities Act of 1933. The rules streamline the shelf registration process to provide registrants with more timely access to capital. Under the new rules, Dominion and Virginia Power meet the definition of a well-known seasoned issuer. This allows the companies to use an automatic shelf registration statement to register any offering of securities, other than those for business combination transactions.

Significant financing activities in 2006 included:

- \$2.3 billion for the repayment of long-term debt;
- \$970 million of common dividend payments;
- \$540 million for the repurchase of common stock; and
- \$300 million for the repayment of affiliated notes payable; partially offset by
- \$2.5 billion from the issuance of long-term debt;
- \$713 million from the net issuance of short-term debt; and
- \$479 million from the issuance of common stock.

CREDIT FACILITIES AND SHORT-TERM DEBT

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 our credit quality and the credit quality of our counterparties. Short-term financing is supported by a \$3.0 billion five-year joint credit facility with Virginia Power and CNG dated February 2006, that can also be used to support up to \$1.5 billion of letters of credit. Short-term financing at CNG is also supported by an amended and restated \$1.7 billion five-year revolving credit facility and a \$1.05 billion 364-day credit facility, both dated February 2006. At December 31, 2006, we had committed lines of credit totaling \$5.75 billion. These lines of credit support commercial paper borrowings, bank loans and letter of credit issuances. Our financial policy precludes issuing commercial paper in excess of our supporting lines of credit. At December 31, 2006, we had the following commercial paper, bank loans and letters of credit outstanding and capacity available under credit facilities:

	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Loans	Outstanding Letters of Credit	Facility Capacity Available
(millions)					
Five-year revolving joint credit facility ⁽¹⁾	\$3,000	\$1,759	\$ —	\$236	\$1,005
Five-year CNG credit facility ⁽²⁾	1,700	—	500	484	716
364-day CNG credit facility ⁽³⁾	1,050	—	—	—	1,050
Totals	\$5,750	\$1,759	\$500	\$720	\$2,771

(1) The \$3.0 billion five-year credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can also be used to support up to \$1.5 billion of letters of credit.

(2) The \$1.7 billion five-year credit facility is primarily used to support the issuance of letters of credit and commercial paper by CNG to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminates in August 2010. In October 2006, we borrowed \$500 million from this facility to repay CNG's \$500 million 2001 Series B 5.375% Senior Notes, which matured on November 1, 2006. We expect to repay the outstanding loan with proceeds received from pending asset sales.

(3) The \$1.05 billion 364-day credit facility was used to support the issuance of letters of credit and commercial paper by CNG to fund collateral requirements under its gas and oil hedging program. The facility was entered into in February 2006 and terminated in February 2007.

We have also entered into several bilateral credit facilities in addition to the facilities above in order to provide collateral required on derivative contracts used in our risk management strategies for gas and oil production operations. At December 31, 2006, 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	\$ 25	\$ 75	June 2004	June 2007
CNG	100	100	—	August 2004	August 2009
CNG ⁽¹⁾	200	—	200	December 2005	December 2010
Totals	\$400	\$125	\$275		

(1) This facility can also be used to support commercial paper borrowings.

In connection with our commodity hedging activities, we are required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, we may satisfy these requirements by electing to either deposit cash, post letters of credit or, in some cases, utilize other forms of security. From time to time, we vary the form of collateral provided to counterparties after weighing the costs and benefits of various factors associated with the different forms of collateral. These factors include short-term borrowing and short-term investment rates, the spread over these short-term rates at which we can issue commercial paper, balance sheet impacts, the costs and fees of alternative collateral postings with these and other counterparties and overall liquidity management objectives.

LONG-TERM DEBT

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

Type	Principal	Rate	Maturity	Issuing Company
	(millions)			
Enhanced junior subordinated notes	\$ 500	6.30%	2066	Dominion
Senior notes	400	variable	2008	Dominion
Enhanced junior subordinated notes	300	7.50%	2066	Dominion
Senior notes	250	5.60%	2016	Dominion
Senior notes	550	6.00%	2036	Virginia Power
Senior notes	450	5.40%	2016	Virginia Power
Total long-term debt issued	\$2,450			

In February 2006, we successfully remarketed \$330 million of 5.75% 2002 Series A senior notes related to our equity-linked debt securities. The senior notes, which will mature in 2008, now carry an annual interest rate of 5.687%.

In February 2006, Dominion Energy Brayton Point, LLC borrowed \$47 million in connection with the Massachusetts Development Finance Agency's issuance of its Solid Waste Disposal Revenue Bonds (Dominion Energy Brayton Point Issue) Series 2006, which mature in 2036 and bear a coupon rate of 5.0%. The bonds were issued pursuant to a trust agreement whereby funds are withdrawn from the trust as improvements are made at our Brayton Point Station located in Somerset, Massachusetts. We have withdrawn \$33 million from the trust as of December 31, 2006.

In June 2006, DCI began consolidating a collateralized debt obligation (CDO) entity in accordance with FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R). At December 31, 2006, this CDO entity had \$385 million of notes payable that mature in January 2017 and are nonrecourse to us.

During 2006, we repaid \$2.3 billion of long-term debt securities.

ISSUANCE OF COMMON STOCK

During 2006, we issued 6.6 million shares of common stock and received proceeds of \$479 million. Of this amount, 4.5 million shares and proceeds of \$330 million resulted from the settlement of stock purchase contracts associated with our 2002 issuance of equity-linked debt securities. The remainder of the shares issued and proceeds received were through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. From May 2006 until November 2006, we issued new common shares in consideration of proceeds received through these programs. In November 2006, we 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.

Pursuant to this authority, in November 2006, we repurchased 500 thousand shares of our common stock for approximately \$40 million. Additionally, in December 2006, we entered into a pre-paid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we will ultimately receive between 5.6 million and 6.5 million shares in exchange for the prepayment of \$500 million. At the time of execution of the ASR, the counterparty delivered to us 5 million shares. The final number of shares delivered to the Company will be determined by a volume weighted-average price of our common stock over the period commencing on December 12, 2006, and terminating on or before May 16, 2007. The actual termination date is at the option of the counterparty. The average price to be used to determine the final shares delivered to the Company is subject to a maximum and minimum price. Assuming normal termination, we will receive a minimum of 560 thousand additional shares. In no event will termination, normal or otherwise, result in the Company delivering shares or additional cash to the counterparty.

At December 31, 2006 the remaining purchase authorization is the lesser of 15.7 million shares or \$1.2 billion of our outstanding common stock.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. We believe that the current credit ratings of Dominion, Virginia Power and CNG (the Dominion Companies) provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to us may affect the Dominion Companies' ability to access these funding sources or cause an increase in the return required by investors.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing an individual company's credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for the Dominion Companies are most affected by each company's financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and "event risk," if applicable, such as major acquisitions or dispositions.

Credit ratings for the Dominion Companies as of February 1, 2007 follow:

	Fitch	Moody's	Standard & Poor's
Dominion Resources, Inc.			
Senior unsecured debt securities	BBB+	Baa2	BBB
Junior subordinated debt securities	BBB	Baa3	BB+
Enhanced junior subordinated notes	BBB	Baa3	BB+
Commercial paper	F2	P-2	A-2
Virginia Power			
Mortgage bonds	A	A3	A-
Senior unsecured (including tax-exempt) debt securities	BBB+	Baa1	BBB
Junior subordinated debt securities	BBB	Baa2	BB+
Preferred stock	BBB	Baa3	BB+
Commercial paper	F2	P-2	A-2
CNG			
Senior unsecured debt securities	BBB+	Baa1	BBB
Junior subordinated debt securities	BBB	Baa2	BB+
Commercial paper	F2	P-2	A-2

In November 2006, Standard & Poor's placed the credit ratings for the Dominion Companies on positive outlook, citing that the sale of the oil and gas assets would be favorable as it improves Dominion's business risk profile by significantly reducing exposure to this segment to less than 5% of overall cash flow. Moody's reaffirmed its credit ratings for the Dominion Companies, stating that the oil and gas divestiture is a potentially positive development for the credit, but will not have a material effect on the ratings at this time. Moody's stated that a divestiture of Dominion's oil and gas operations will substantially reduce the nonregulated revenues, earnings, cash flows and assets as a percentage of the consolidated company, which will, in turn, significantly lower our overall business and operating risk profile. Fitch reaffirmed its credit ratings for the Dominion Companies, stating that the closing of the potential oil and gas sale would alleviate several of Fitch's primary rating concerns and increase the share of consolidated cash flows from more stable businesses.

Generally, a downgrade in an individual company's credit rating would not restrict its ability to raise short-term and long-term financing as long as its credit rating remains "investment grade," but it would increase the cost of borrowing. We work closely with Fitch, Moody's and Standard & Poor's with the objective of maintaining our current credit ratings. In order to maintain our current ratings, we may find it necessary to modify our business plans and such changes may adversely affect our growth and earnings per share.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, the Dominion Companies must enter into enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to our capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to the Dominion Companies.

Some of the typical covenants include:

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

We are required to pay minimal annual commitment fees to maintain our credit facilities. In addition, our credit agreements contain various terms and conditions that could affect our ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2006, the calculated total debt to total capital ratio for our companies, pursuant to the terms of the agreements, was as follows:

Company	Maximum Ratio	Actual Ratio ⁽¹⁾
Dominion Resources, Inc.	65%	54%
Virginia Power	65%	47%
CNG	65%	47%

(1) Indebtedness as defined by the bank agreements excludes junior subordinated notes payable reflected as long-term debt on our Consolidated Balance Sheets.

These provisions apply separately to the Dominion Companies. If any one of the Dominion Companies or any of that specific company's material subsidiaries fail to make payment on various debt obligations in excess of \$35 million, the lenders could require that respective company to accelerate its repayment of any outstanding borrowings under the credit facility and the lenders could terminate their commitment to lend funds to that company. Accordingly, any defaults on indebtedness by CNG or any of its material subsidiaries would not affect the lenders' commitment to Virginia Power. Similarly, any defaults on indebtedness by Virginia Power or any of its material subsidiaries would not affect the lenders' commitment to CNG. Likewise, any default by Dominion will not affect the lender's commitment to Virginia Power or CNG. However, any default by either CNG or Virginia Power would also affect in like manner the lenders' commitment to Dominion under the joint credit agreement.

In June 2006 and September 2006, we executed Replacement Capital Covenants (RCCs) in connection with our offering of \$300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and \$500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. We have initially designated the \$250 million 8.4% Capital Securities of Dominion Resources Capital Trust III that were issued in January 2001 as covered debt under the RCCs. In the future, we will be allowed to change the series of our debt designated as covered debt under the RCCs. Under the terms of the RCCs, we agree not to redeem or repurchase all or part of the June or September hybrids prior to June 30 or September 30, 2036, respectively, unless we issue qualifying securities to non-affiliates in a replacement offering in the 180 days prior to

the redemption or repurchase date. The proceeds we receive from the replacement offering, adjusted by a predetermined factor, must exceed the redemption or repurchase price. Qualifying securities include common stock, preferred stock and other securities that generally rank equal to or junior to the hybrids and include distribution deferral and long-dated maturity features similar to the hybrids. For purposes of the RCCs, non-affiliates include individuals enrolled in our dividend reinvestment plan, direct stock purchase plan and employee benefit plans.

We monitor the covenants on a regular basis in order to ensure that events of default will not occur. Other than the RCCs discussed above, as of December 31, 2006, there have been no changes to or events of default under our debt covenants.

Dividend Restrictions

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

See Note 18 to our Consolidated Financial Statements 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 or deferral of interest payments on enhanced junior subordinated notes.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

We are party to numerous contracts and arrangements obligating the Company to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services and financial derivatives. Presented below is a table summarizing cash payments that may result from contracts to which we are a party as of December 31, 2006. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market-based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities in our Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable, and certain derivative instruments. The majority of our current liabilities will be paid in cash in 2007.

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
(millions)					
Long-term debt ⁽¹⁾	\$2,479	\$2,021	\$2,443	\$10,370	\$17,313
Interest payments ⁽²⁾	1,005	1,662	1,378	9,904	13,949
Leases	209	345	250	294	1,098
Purchase obligations ⁽³⁾ :					
Purchased electric capacity for utility operations	414	745	697	2,207	4,063
Fuel to be used for utility operations	717	838	367	573	2,495
Fuel to be used for nonregulated operations	28	68	58	172	326
Production handling	54	69	26	5	154
Pipeline transportation and storage	149	241	121	85	596
Energy commodity purchases for resale ⁽⁴⁾	469	31	12	4	516
Other ⁽⁵⁾	594	166	49	68	877
Other long-term liabilities ⁽⁶⁾ :					
Financial derivative—commodities ⁽⁴⁾	839	189	2	—	1,030
Other contractual obligations ⁽⁷⁾	60	84	15	—	159
Total cash payments	\$7,017	\$6,459	\$5,418	\$23,682	\$42,576

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders.

(2) Does not reflect our ability to defer payments related to our trust preferred securities and enhanced junior subordinated notes.

(3) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.

(4) Represents the summation of settlement amounts, by contracts, due from us if all physical or financial transactions among our counterparties and the Company were liquidated and terminated.

(5) Includes capital and operations and maintenance commitments, onshore and offshore drilling rigs and funding for our investment in a wind-power facility as discussed in Note 23 to our Consolidated Financial Statements.

(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations that are not contractually fixed as to timing and amount. See Notes 14, 15 and 22 to our Consolidated Financial Statements. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year.

(7) Includes interest rate swap agreements.

Our planned capital expenditures during 2007 and 2008 are expected to total approximately \$4.4 billion and \$4.6 billion, respectively. These expenditures are expected to include construction and expansion of electric generation and LNG facilities, environmental upgrades, construction improvements and expansion of gas and electric transmission and distribution assets,

purchases of nuclear fuel and expenditures to explore for and develop natural gas and oil properties. We expect to fund our capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings.

Based on available generation capacity and current estimates of growth in customer demand, we will need additional generation in the future. We currently have plans to restart our Hopewell plant in 2007, a 63 Mw (at net summer capability) coal burning plant located in Hopewell, Virginia, which has been out of service since 2003, and we are evaluating a 290 Mw (at net summer capability) expansion of our Ladysmith site in Ladysmith, Virginia. We are also leading a consortium of companies that are considering building a 500 to 600 Mw coal-fired plant in southwest Virginia. We will continue to evaluate the development of new plants to meet customer demand for additional generation needs in the future. Through 2009, we will continue to meet any additional capacity requirements through market purchases.

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

Use of Off-Balance Sheet Arrangements

GUARANTEES

We primarily enter into guarantee arrangements on behalf of our consolidated subsidiaries. These arrangements are not subject to the recognition and measurement provisions of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. See Note 23 to our Consolidated Financial Statements for further discussion of these guarantees.

At December 31, 2006, we have issued \$32 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 E&P 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 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. We believe this scenario is improbable and have not recognized any significant liabilities related to any of these arrangements.

In 2006, we, along with three other gas and oil exploration companies, executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. We anticipate that mechanical completion of the Thunder Hawk facility will occur in 2009 and that the processing of our production will start by 2010. Due to current offshore insurance market conditions, it is anticipated that the Thunder Hawk facility will only be partially insured against a catastrophic full or partial loss. We, along with the three other participating producers, will be required to continue to make demand payments in the event of a catastrophic loss if insurance payments are not sufficient to pay the lessor's outstanding debt incurred for the Thunder Hawk facility. The agreements require that we pay a demand charge of approximately \$63 million over five years starting on the day after the mechanical completion of the Thunder

Hawk facility. Our obligation will terminate upon the earlier event of full payment of the lessor's debt incurred for the Thunder Hawk facility or the full payment of our demand charge obligation. We believe that it is unlikely that we would be required to perform under this guarantee and have not recognized any significant liabilities for this arrangement. The agreements also require the payment of production processing fees including a minimum processing fee if yearly production processing fees are below specified amounts. Our maximum obligation for the minimum processing fee would be approximately \$3 million per year. Our obligation for the payment of these processing fees will terminate upon the cessation of our production.

LEASING ARRANGEMENT

We have an agreement to lease the Fairless power station in Pennsylvania, 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. 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 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.

Benefits of this arrangement include:

- Certain tax benefits as we are considered the owner of the leased property for tax purposes. As a result, we are entitled to tax deductions for depreciation not recognized for financial accounting purposes; and
- As an operating lease for financial accounting purposes, the asset and related borrowings used to finance the construction of the asset are not included in our Consolidated Balance Sheets. Although this improves measures of leverage calculated using amounts reported in our Consolidated Financial Statements, credit rating agencies view lease obligations as debt equivalents in evaluating our credit profile.

FUTURE ISSUES AND OTHER MATTERS

Status of Electric Restructuring in Virginia

1999 VIRGINIA RESTRUCTURING ACT

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

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

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

VIRGINIA FUEL EXPENSES

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

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

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007.

While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1, 2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

STRANDED COSTS

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. We believe capped electric retail rates will provide an opportunity to recover our potential stranded costs, depending on market prices of electricity

and other factors. Recovery of our potential stranded costs remains subject to numerous risks, even in the capped-rate environment. These risks include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items.

The generation-related cash flows provided by the 1999 Virginia Restructuring Act are intended to compensate us for continuing to provide generation services and to allow us to incur costs to restructure such operations during the transition period. As a result, during the transition period, our earnings may increase to the extent that we can reduce operating costs for our utility generation-related operations. Conversely, the same risks affecting the recovery of our stranded costs may also adversely impact our margins during the transition period. Accordingly, we could realize the negative economic impact of any such adverse event. Using cash flows from operations during the transition period, we may further alter our cost structure or choose to make additional investments in our business.

2007 VIRGINIA RESTRUCTURING ACT AMENDMENTS

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5 Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5 Mw. Also, after the end of capped rates, the Virginia Commission would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

- Initiate a base rate case for each utility during the first six months of 2009, as a result of which the Virginia Commission:
 - establishes a return on equity (ROE) no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments;
 - shall increase base rates, if needed, to allow the utility the opportunity to recover its costs and earn a fair rate of return, if the utility is found to have earnings more than 50 basis points below the established ROE;
 - may reduce rates or, alternatively, order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE; and
 - may authorize performance incentives, if appropriate.
- After the initial rate case, review base rates biennially, as a result of which the Virginia Commission:
 - establishes an ROE no lower than that reported by a group of utilities within the southeastern U.S., with certain limitations on earnings and rate adjustments; however, if the Virginia Commission finds that such ROE limit at that time exceeds the ROE set at the time of the initial base rate case in 2009 by more than the percentage increase in the Consumer Price Index in the interim, it may reduce that lower ROE limit to a level that increases the initial ROE by only as much as the change in the Consumer Price Index;

- shall increase base rates, if needed, to allow the utility the opportunity to recover its costs and earn a fair rate of return if the utility is found to have earnings more than 50 basis points below the established ROE; or
- may order a credit to customers if the utility is found to have earnings more than 50 basis points above the established ROE, and reduce rates if the utility is found to have such excess earnings during two consecutive biennial review periods; and
- may authorize performance incentives if appropriate.
- Authorize stand-alone rate adjustments for recovery of certain costs, including new generation projects, major generating unit modifications, environmental compliance projects, FERC-approved costs for transmission service, energy efficiency and conservation programs, and renewable energy programs; and
- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

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

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

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

Transmission Expansion Plan

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

Offshore Oil and Gas Leases

A bill passed by the U.S. House of Representatives on January 16, 2007, but not yet enacted into law, addresses certain federal offshore oil and gas leases issued in 1998 and 1999 that do not include a provision requiring royalties to be paid on specified royalty suspension volumes when oil and gas commodity futures closing prices exceed specified threshold levels (as is the case under current market conditions). The bill imposes a conservation of resources fee of \$1.25 per million British thermal units (MMBtu) of gas and \$9.00 per barrel oil (2005 dollars) produced from such leases on and after October 1, 2006 in calendar years when the average oil or gas (as applicable) commodity futures monthly closing prices on the New York Mercantile Exchange (NYMEX) exceed \$4.34 per MMBtu for gas or \$34.73 for oil (2005 dollars). In addition, commencing on and after October 1, 2006, in calendar years when the average NYMEX monthly closing prices exceed the foregoing thresholds, a conservation of resources fee of \$3.75 per acre per lease per year is imposed on such leases that are non-producing. The bill permits lessees to avoid payment of the foregoing fee by agreeing to lease amendments that provide that royalties are payable with respect to royalty suspension volumes on and after October 1, 2006 when the foregoing threshold conditions are met. Finally, the bill imposes sanctions on lessees, including disqualification from future offshore lease sales, for those who do not enter into such lease amendments and fail to pay the fee. The Senate is considering similar legislation.

Common Stock Dividend Increase

In January 2007, our quarterly dividend rate increased from 69 cents per share to 71 cents per share, for an annual rate in 2007 of \$2.84. While all dividends are payable only as and when declared by the Board of Directors, our expected cash flow and earnings should enable us to pay dividends at the current rate and to make future increases when our Board of Directors deems it financially prudent. The Board of Directors declares common stock dividends on a quarterly basis.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. To the extent that environmental costs are incurred in connection with operations regulated by the Virginia Commission, during the period ending December 31, 2010, in excess of the level currently included in the Virginia jurisdictional electric retail rates, our results of operations will decrease. After that date, recovery through regulated rates may be sought for only those environmental costs related to regulated electric transmission and distribution operations and recovery, if any, through the generation component of rates will be dependent upon the market price of electricity. We also may seek recovery through regulated rates for environmental expenditures related to regulated gas transmission and distribution operations. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments.

ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

We incurred approximately \$138 million, \$205 million and \$132 million of expenses (including depreciation) during 2006, 2005 and 2004, respectively, in connection with environmental protection and monitoring activities and expect these expenses to be approximately \$181 million and \$188 million in 2007 and 2008, respectively. In addition, capital expenditures related to environmental controls were \$332 million, \$140 million and \$94 million for 2006, 2005 and 2004, respectively. These expenditures are expected to be approximately \$300 million and \$174 million for 2007 and 2008, respectively.

CLEAN AIR ACT (CAA) COMPLIANCE

In March 2005, the Environmental Protection Agency (EPA) Administrator signed both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These rules, when implemented, will require significant reductions in sulfur dioxide (SO₂), nitrogen oxide (NO_x) and mercury emissions from electric generating facilities. The SO₂ and NO_x emission reduction requirements are imposed in two phases, with initial reduction levels targeted for 2009 (NO_x) and 2010 (SO₂), and a second phase of reductions targeted for 2015 (SO₂ and NO_x). The mercury emission reduction requirements are also in two phases, with initial reduction levels targeted for 2010 and a second phase of reductions targeted for 2018. The new rules allow for the use of cap-and-trade programs. States are currently developing implementation plans, which will determine the levels and timing of required emission reductions in each of the states within which we own and operate affected generating facilities. Several of these states have issued proposed regulations for the implementation of CAIR and CAMR. West Virginia has adopted both final rules. Illinois has adopted CAMR and is more strict than the federal requirements. In April 2006, legislation titled, *Air Emissions Control*, which addresses many of the requirements of CAIR and CAMR, was adopted in Virginia and is more strict than the federal requirements. This legislation, however, does not serve as Virginia's final plan for the implementation of CAIR and CAMR. Illinois has proposed, but not yet finalized, regulations to implement CAIR, which are also more strict than the federal requirements. Separate from CAIR and CAMR, Massachusetts has regulations specifically targeting reductions in NO_x, SO₂, carbon dioxide (CO₂) and mercury emissions from our affected facilities in Massachusetts. These CAA regulatory and legislative actions will require additional reductions in emissions from our fossil fuel-fired generating facilities and are already addressed in our current compliance planning. In June 2005, the EPA finalized amendments to the Regional Haze Rule, also known as the Clean Air Visibility Rule (CAVR). The states have not yet finalized regulations to implement CAVR. Although we anticipate that the emission reductions achieved through compliance with CAIR and CAMR will address CAVR, at this time we cannot predict with certainty any additional financial impacts of the regional haze regulations on our operations at this time. Implementation of projects to comply with these SO₂, NO_x and mercury limitations, and other state emission control programs are ongoing and will be influenced by changes in the regulatory environment, availability of emission allowances and emission control technology. In response to these CAA requirements, we estimate that we will

make capital expenditures at our affected generating facilities of approximately \$958 million during the period 2007 through 2011.

In March 2004, the State of North Carolina filed a petition with the EPA under Section 126 of the CAA seeking additional NO_x and SO₂ reductions from electrical generating units in thirteen states, claiming emissions from those units are contributing to air quality problems in North Carolina. We have electrical generating units in six of the thirteen states. In March 2006, the EPA issued a final rulemaking through which it denied the North Carolina petition on the basis that the implementation of CAIR adequately addresses the air quality issues identified by North Carolina. Therefore, we do not anticipate additional expenditures in relation to this matter.

OTHER

We operate two fossil fuel-fired generating power stations in Massachusetts that are subject to the implementation of CO₂ emission regulations issued by the Massachusetts Department of Environmental Protection. The final CO₂ regulations have been promulgated and contain provisions that limit our liability through the establishment of alternative compliance payments. Based on our analysis we estimated that the impact of these regulations will not be material.

Additionally, in January 2007, the Governor of Massachusetts signed the Regional Greenhouse Gas Initiative, committing Massachusetts to a multi-state effort to reduce emissions of carbon dioxide. Implementing regulations in Massachusetts have yet to be promulgated. Until the implementing regulations are promulgated, it is not possible to predict the financial impact that may result.

CLEAN WATER ACT COMPLIANCE

In July 2004, the EPA published regulations that govern existing utilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The EPA's rule presents several compliance options. We have been evaluating information from certain of our existing power stations and had expected to spend approximately \$8 million over the next 2 years conducting studies and technical evaluations. However, in January 2007, the U.S. Court of Appeals for the Second Circuit issued a decision on an appeal of the regulations, remanding the rule to the EPA. We cannot predict the outcome of the EPA regulatory process or determine with any certainty what specific controls may be required.

In August 2006, the Connecticut Department of Environmental Protection (CTDEP) issued a notice of a Tentative Determination to renew Millstone Power Station's pollution elimination discharge permit, which included a draft copy of the revised permit. An administrative hearing will be held on the draft permit with a Final Determination expected to be issued by the CTDEP within the next year. Until the final permit is reissued, it is not possible to predict the financial impact that may result.

In October 2003, the EPA and the Massachusetts Department of Environmental Protection each issued new National Pollutant Discharge Elimination System (NPDES) permits for the Brayton Point Power Station. The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. In November 2003, appeals were filed with the EPA Envi-

ronmental Appeals Board (EAB) and the Division of Administrative Law Appeals in Massachusetts, and both permits were stayed. In February 2006, the EAB remanded a portion of the EPA's NPDES permit to the EPA for reconsideration. In November 2006, EPA issued its determination on remand regarding four remaining issues appealed by Brayton Point concerning its NPDES permit. In January 2007, Brayton Point appealed three of those issues to the EPA EAB. Both permits are stayed pending the outcome of the EPA process. Until the remand process and any resulting appeals are completed, the outcome of this matter cannot be predicted.

FUTURE ENVIRONMENTAL REGULATIONS

From time to time, the U.S. Congress considers various legislative proposals that would require generating facilities to comply with more stringent air emissions standards. Emission reduction requirements under consideration would be phased in under periods of up to ten to fifteen years. If these new proposals are adopted, additional significant expenditures may be required.

In 1997, the U.S. signed an International Protocol (Protocol) to limit man-made greenhouse emissions under the United Nations Framework Convention on Climate Change. However, the Protocol will not become binding unless approved by the U.S. Senate. The Bush Administration has indicated that it will not pursue ratification of the Protocol and has set a voluntary goal of reducing the nation's greenhouse gas emission intensity by 18% during the period 2002 through 2012. We expect continuing legislative efforts in the U.S. Congress to include provisions seeking to target the reductions of greenhouse gas emissions. In addition to possible federal action, some of the states in which we operate have already or may adopt carbon reduction programs. The cost of compliance with the Protocol or other greenhouse gas reduction programs could be significant. Given the highly uncertain outcome and timing of future action, if any, by the U.S. federal government and states on this issue, we cannot predict the financial impact of future climate change actions on our operations at this time.

MARKET RISK SENSITIVE INSTRUMENTS AND RISK MANAGEMENT

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, foreign currency exchange rates, interest rates and equity security prices as described below. Commodity price risk is present in our electric operations, gas and oil production and procurement operations, and energy marketing and trading operations due to the exposure to market shifts in prices received and paid for natural gas, oil, electricity and other commodities. We use commodity derivative contracts to manage price risk exposures for these operations. We are exposed to foreign currency exchange rate risks related to our purchases of fuel and fuel services denominated in foreign currencies. Interest rate risk is generally related to our outstanding debt. In addition, we are exposed to equity price risk through various portfolios of equity securities.

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

Commodity Price Risk

We manage price risk associated with purchases and sales of natural gas, oil, electricity and certain other commodities using commodity-based financial derivative instruments held for non-trading purposes. As part of our strategy to market energy and to manage related risks, we also hold commodity-based financial derivative instruments for trading purposes.

The derivatives used to manage risk are executed within established policies and procedures and include instruments such as futures, forwards, swaps and options that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the fair value of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on actively quoted market prices.

A hypothetical 10% unfavorable change in market prices of our non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately \$597 million and \$691 million as of December 31, 2006 and 2005, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately \$3 million in the fair value of our commodity-based financial derivative instruments held for trading purposes as of December 31, 2006 and 2005, respectively.

The impact of a change in energy commodity prices on our non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from sales.

Foreign Currency Exchange Risk

Our Canadian natural gas and oil E&P activities are relatively self-contained within Canada. As a result, our exposure to foreign currency exchange risk for these activities is limited primarily to the effects of translation adjustments that arise from including that operation in our Consolidated Financial Statements. We monitor this exposure and believe it is not material. In addition, we manage our foreign exchange risk exposure associated with anticipated future purchases of nuclear fuel processing services denominated in foreign currencies by utilizing currency forward contracts. As a result of holding these contracts as hedges, our exposure to foreign currency risk is minimal. A hypothetical 10% unfavorable change in relevant foreign exchange rates would have resulted in a decrease of approximately \$3 million and \$8 million in the fair value of currency forward contracts held at December 31, 2006 and 2005, respectively.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For financial instruments outstanding at December 31, 2006, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately \$25 million. A hypothetical 10% increase in market interest rates, as determined at

December 31, 2005, would have resulted in a decrease in annual earnings of approximately \$20 million.

In addition, we retain ownership of mortgage investments, including subordinated bonds and interest-only residual assets retained from securitizations of mortgage loans originated and purchased in prior years. Note 27 to our Consolidated Financial Statements discusses the impact of changes in value of these investments.

Investment Price Risk

We are subject to investment price risk due to marketable securities held as investments in decommissioning trust funds. These marketable securities are managed by third-party investment managers and are reported in our Consolidated Balance Sheets at fair value. We recognized net realized gains (including investment income) on nuclear decommissioning trust investments of \$63 million and \$67 million in 2006 and 2005, respectively. We recorded, in AOCI, gross unrealized gains on these investments of \$194 million in 2006 and net unrealized gains of \$27 million in 2005.

We also sponsor employee pension and other postretirement benefit plans that hold investments in trusts to fund benefit payments. To the extent that the values of investments held in these trusts decline, the effect will be reflected in our recognition of the periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans. Our pension and other postretirement benefit plans experienced net realized and unrealized gains of \$674 million and \$484 million in 2006 and 2005, respectively. As of December 31, 2006, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would result in an increase in net periodic cost of approximately \$11 million for pension benefits and \$2 million for other postretirement benefits. As of December 31, 2005, a hypothetical 0.25% decrease in the assumed rates of return on our plan assets would have resulted in an increase in net periodic cost of approximately \$10 million for pension benefits and \$2 million for other postretirement benefits.

Risk Management Policies

We have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, we have established an independent function at the corporate level to monitor compliance with the risk management policies of all subsidiaries. We maintain credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, we also monitor the financial condition of existing counterparties on an ongoing basis. Based on our credit policies and the December 31, 2006 provision for credit losses, management believes that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a

number of these factors below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements*.

Our operations are weather sensitive. Our results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. In addition, severe weather, including hurricanes, winter storms and droughts, can be destructive, causing outages, production delays and property damage that require us to incur additional expenses.

We are subject to complex governmental regulation that could adversely affect our operations. Our operations are subject to extensive federal, state and local regulation and require numerous permits, approvals and certificates from various governmental agencies. We must also comply with environmental legislation and associated regulations. Management believes that the necessary approvals have been obtained for our existing operations and that our business is conducted in accordance with applicable laws. However, new laws or regulations, or the revision or reinterpretation of existing laws or regulations, may require us to incur additional expenses.

Costs of environmental compliance, liabilities and litigation could exceed our estimates, which could adversely affect our results of operations. Compliance with federal, state and local environmental laws and regulations may result in increased capital, operating and other costs, including remediation and containment expenses and monitoring obligations. In addition, we may be a responsible party for environmental clean-up at a site identified by a regulatory body. Management cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up and compliance costs, and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

We are exposed to cost-recovery shortfalls because of capped base rates and amendments to the fuel factor statute in effect in Virginia for our regulated electric utility. Under the 1999 Virginia Restructuring Act, as amended, our base rates remain capped through December 31, 2010 unless sooner modified or terminated. Although this Act allows for the recovery of certain generation-related costs during the capped rates period, we remain exposed to numerous risks of cost-recovery shortfalls. These risks include exposure to stranded costs, future environmental compliance requirements, certain tax law changes, costs related to hurricanes or other weather events, inflation, the cost of obtaining replacement power during unplanned plant outages and increased capital costs.

In addition, our current Virginia fuel factor provisions are locked-in until July 1, 2007, with no deferred fuel accounting. As a result, until July 1, 2007 we are exposed to fuel price and other risks. These risks include exposure to increased costs of fuel, including purchased power costs, differences between our projected and actual power generation mix and generating unit performance (which affects the types and amounts of fuel we use) and differences between fuel price assumptions and actual fuel prices. Annual fuel rate adjustments, with deferred fuel accounting for over- or under-recoveries of fuel costs, will be instituted for three twelve-month periods beginning July 1, 2007. The Virginia

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

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

Our merchant power business is operating in a challenging market, which could adversely affect our results of operations and future growth. The success of our merchant power business depends upon favorable market conditions as well as our ability to find buyers willing to enter into power purchase agreements at prices sufficient to cover operating costs. We attempt to manage these risks by entering into both short-term and long-term fixed price sales and purchase contracts and locating our assets in active wholesale energy markets. However, high fuel and commodity costs and excess capacity in the industry could adversely impact our results of operations.

There are risks associated with the operation of nuclear facilities. We operate nuclear facilities that are subject to risks, including the threat of terrorist attack and ability to dispose of spent nuclear fuel, the disposal of which is subject to complex federal and state regulatory constraints. These risks also include the cost of and our ability to maintain adequate reserves for decommissioning, costs of replacement power, costs of plant maintenance and exposure to potential liabilities arising out of the operation of these facilities. We maintain decommissioning trusts and external insurance coverage to mitigate the financial exposure to these risks. However, it is possible that costs arising from claims could exceed the amount of any insurance coverage.

The use of derivative instruments could result in financial losses and liquidity constraints. We use derivative instruments, including futures, forwards, financial transmission rights, options and swaps, to manage our commodity and financial market risks. In addition, we purchase and sell commodity-based contracts in the natural gas, electricity and oil markets for trading purposes. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively-quoted market prices and pricing information from

external sources, the valuation of these contracts involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, we use derivatives to hedge future sales of our merchant generation and gas and oil production, which may limit the benefit we would otherwise receive from increases in commodity prices. These hedge arrangements generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties to cover the fair value of covered contracts in excess of agreed upon credit limits. When commodity prices rise to levels substantially higher than the levels where we have hedged future sales, we may be required to use a material portion of our available liquidity and obtain additional liquidity to cover these collateral requirements. In some circumstances, this could have a compounding effect on our financial liquidity and results of operations.

Derivatives designated under hedge accounting to the extent not fully offset by the hedged transaction can result in ineffectiveness losses. These losses primarily result from differences in the location and specifications of the derivative hedging instrument and the hedged item and could adversely affect our results of operations.

Our operations in regards to these transactions are subject to multiple market risks including market liquidity, counterparty credit strength and price volatility. These market risks are beyond our control and could adversely affect our results of operations and future growth.

For additional information concerning derivatives and commodity-based trading contracts, see *Market Risk Sensitive Instruments and Risk Management* and Notes 2 and 8 to our Consolidated Financial Statements.

Our E&P business is affected by factors that cannot be predicted or controlled and that could damage facilities, disrupt production or reduce the book value of our assets. Factors that may affect our financial results include, but are not limited to: damage to or suspension of operations caused by weather, fire, explosion or other events at our or third-party gas and oil facilities, fluctuations in natural gas and crude oil prices, results of future drilling and well completion activities, our ability to acquire additional land positions in competitive lease areas, operational risks that could disrupt production and geological and other uncertainties inherent in the estimate of gas and oil reserves.

Short-term market declines in the prices of natural gas and oil could adversely affect our financial results by causing a permanent write-down of our natural gas and oil properties as required by the full cost method of accounting. Under the full cost method, all direct costs of property acquisition, exploration and development activities are capitalized. If net capitalized costs exceed the present value of estimated future net revenues based on hedge-adjusted period-end prices from the production of proved gas and oil reserves (the ceiling test) at the end of any quarterly period, then a permanent write-down of the assets must be recognized in that period.

In the past, we have maintained business interruption, property damage and other insurance for our E&P operations. However, the increased level of hurricane activity in the Gulf of Mexico led our insurers to terminate certain coverages for our E&P operations; specifically, our Operator's Extra Expense (OEE), offshore property damage and offshore business

interruption coverage was terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remained in place for our E&P operations. Our OEE coverage for both onshore and offshore E&P operations was reinstated under a new policy. However, efforts to replace the terminated insurance for our E&P operations for offshore property damage and offshore business interruption with similar insurance on commercially reasonable terms were unsuccessful. This lack of insurance could adversely affect our results of operations.

Our decision to pursue a sale of most of our E&P assets is expected to be dilutive to earnings, could have an adverse impact on our results of operations and may not yield the benefits that we expect. On November 1, 2006, we announced our decision to pursue a sale of all of our E&P assets, excluding those assets located in the Appalachian Basin. We expect that a sale of our E&P assets would reduce future earnings in the near term. Although we expect that shareholder value would increase over time, we can give no assurance that this will occur. While our management believes it would be able to execute any sale or sales by mid-2007, we may not be able to sell our E&P assets within the expected time frame. If we sell our E&P assets, we cannot be certain of the price we would receive or the impact that such a sale and the use of proceeds from any sale would have on our results of operations. We may also incur significant costs or be required to record certain charges in connection with any sale and in connection with transactions related to the deployment of the proceeds from any sale.

Additionally, uncertainty about the effect of the proposed disposition may have an adverse effect on the Company, particularly our E&P business. Although we have taken steps to reduce any adverse effects, including providing retention agreements for employees, these uncertainties may impair our ability to attract, retain and motivate key personnel and could cause partners, customers, suppliers and others that deal with our E&P business to seek to change future business relationships. Our E&P business could be harmed if, despite our retention efforts, key employees depart as a result of the proposed disposition.

An inability to access financial markets could affect the execution of our business plan. Dominion and our Virginia Power and CNG subsidiaries rely on access to short-term money markets, longer-term capital markets and banks as significant sources

of liquidity for capital requirements and collateral requirements related to hedges of future gas and oil production not satisfied by the cash flows from our operations. Management believes that Dominion and our subsidiaries will maintain sufficient access to these financial markets based upon current credit ratings. However, certain disruptions outside of our control may increase our cost of borrowing or restrict our ability to access one or more financial markets. Such disruptions could include an economic downturn, the bankruptcy of an unrelated energy company or changes to our credit ratings. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled.

Changing rating agency requirements could negatively affect our growth and business strategy. As of February 1, 2007, Dominion's senior unsecured debt is rated BBB, positive outlook, by Standard & Poor's; Baa2, stable outlook, by Moody's; and BBB+, stable outlook, by Fitch. In order to maintain our current credit ratings in light of existing or future requirements, we may find it necessary to take steps or change our business plans in ways that may adversely affect our growth and earnings per share. A reduction in Dominion's credit ratings or the credit ratings of our Virginia Power and CNG subsidiaries by Standard & Poor's, Moody's or Fitch could increase our borrowing costs and adversely affect operating results and could require us to post additional collateral in connection with some of our price risk management activities.

Potential changes in accounting practices may adversely affect our financial results. We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

Failure to retain and attract key executive officers and other skilled professional and technical employees could have an adverse effect on our operations. Our business is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees in some areas is high and the inability to retain and attract these employees could adversely affect our business and future operating results.

SELECTED FINANCIAL DATA

	2006 ⁽¹⁾	2005 ⁽²⁾	2004 ⁽³⁾	2003 ⁽⁴⁾	2002
(millions, except per share amounts)					
Operating revenue	\$16,482	\$17,971	\$13,929	\$12,035	\$10,191
Income from continuing operations before cumulative effect of changes in accounting principles	1,563	1,047	1,273	942	1,364
Loss from discontinued operations, net of tax ⁽⁵⁾	(183)	(8)	(24)	(635)	(2)
Cumulative effect of changes in accounting principles, net of tax	—	(6)	—	11	—
Net income	1,380	1,033	1,249	318	1,362
Income from continuing operations before cumulative effect of changes in accounting principles per common share—basic	4.47	3.06	3.87	2.97	4.85
Net income per common share—basic	3.95	3.02	3.80	1.00	4.85
Income from continuing operations before cumulative effect of changes in accounting principles per common share—diluted	4.45	3.04	3.85	2.95	4.83
Net income per common share—diluted	3.93	3.00	3.78	1.00	4.82
Dividends paid per share	2.76	2.68	2.60	2.58	2.58
Total assets	49,269	52,660	45,418	43,546	39,239
Long-term debt ⁽⁶⁾	14,791	14,653	15,507	15,776	12,060
Preferred securities of subsidiary trusts ⁽⁶⁾	—	—	—	—	1,397

(1) Includes a \$164 million after-tax impairment charge resulting from the classification of three of our natural gas-fired merchant generation peaking facilities (Peaker facilities) as held for sale and a \$104 million after-tax charge resulting from the write-off of certain regulatory assets related to the pending sale of two of our regulated gas distribution subsidiaries. See Note 9 to our Consolidated Financial Statements.

(2) Includes a \$272 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. Also in 2005, we adopted a new accounting standard that resulted in the recognition of the cumulative effect of a change in accounting principle. See Note 3 to our Consolidated Financial Statements.

(3) Includes a \$112 million after-tax charge related to our interest in a long-term power tolling contract that was divested in 2005 and a \$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 during the third quarter.

(4) Includes \$122 million of after-tax incremental restoration expenses associated with Hurricane Isabel. Also in 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, 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*, Statement 133 Implementation Issue No. C20, *Interpretation of the Meaning of 'Not Clearly and Closely Related' in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature*, and FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), which resulted in the recognition of the cumulative effect of changes in accounting principles.

(5) Reflects the net impact of our discontinued operations resulting from the pending sale of the Peaker facilities and the net impact of our discontinued telecommunications operations that were sold in May 2004. See Note 9 to our Consolidated Financial Statements.

(6) Upon adoption of FIN 46R on December 31, 2003 with respect to special purpose entities, we began reporting as long-term debt our junior subordinated notes held by five capital trusts, rather than the trust preferred securities issued by those trusts.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

The Audit Committee of the Board of Directors of Dominion, composed entirely of independent directors, meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss auditing, internal control, and financial reporting matters of Dominion and to ensure that each is properly discharging its responsibilities. Both the independent registered public accounting firm and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require our 2006 Annual Report to contain a management's report and a report of the independent registered public accounting firm regarding the effectiveness of internal control. As a basis for our report, we tested and evaluated the design and operating effectiveness of internal controls. Based on our assessment as of December 31, 2006, we make the following assertion:

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

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

On December 31, 2003, we adopted Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, for our interests in special purpose entities, referred to as SPEs. As a result, we have included in our consolidated financial statements certain SPEs. Our Consolidated Balance Sheet, as of December 31, 2006, reflects \$337 million of net property, plant and equipment and \$370 million of related debt attributable to these SPEs. As these SPEs are owned by unrelated parties, we do not have the authority to dictate or modify, and therefore could not assess the internal controls in place at these entities. Our conclusion regarding the effectiveness of Dominion's internal control does not extend to the internal controls of these SPEs.

We evaluated Dominion's internal control over financial reporting as of December 31, 2006. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we believe that Dominion maintained effective internal control over financial reporting as of December 31, 2006.

The independent registered public accounting firm that audited the financial statements has issued an attestation report on our assessment of the internal control over financial reporting.

February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries (the “Company”) as of December 31, 2006 and 2005, and the related consolidated statements of income, common shareholders’ equity and comprehensive income, and of cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Resources, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for

each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company changed its methods of accounting to adopt new accounting standards for pension and other postretirement benefit plans, share-based payments, and purchases and sales of inventory with the same counterparty in 2006, and for conditional asset retirement obligations in 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company’s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007, expresses an unqualified opinion on management’s assessment of the effectiveness of the Company’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.



Richmond, Virginia
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited management's assessment, included in paragraphs 5-8 of the accompanying Management's Annual Report on Internal Control over Financial Reporting, that Dominion Resources, Inc. (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Annual Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at certain special purpose entities consolidated under Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*. The Company's Consolidated Balance Sheet, as of December 31, 2006, reflects \$337 million of net property, plant and equipment and \$370 million of related debt attributable to those special purpose entities. Accordingly, our audit did not include the internal control over financial reporting at those special purpose entities. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

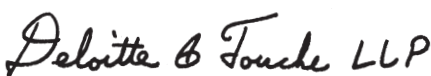
A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes

in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 28, 2007, expresses an unqualified opinion on those financial statements and includes an explanatory paragraph referring to changes in accounting principles.



Richmond, Virginia
February 28, 2007

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2006	2005	2004
(millions, except per share amounts)			
Operating Revenue	\$16,482	\$17,971	\$13,929
Operating Expenses			
Electric fuel and energy purchases	3,236	4,670	2,126
Purchased electric capacity	481	504	587
Purchased gas	2,937	3,941	2,927
Other energy-related commodity purchases	1,022	1,391	989
Other operations and maintenance	3,280	3,054	2,755
Depreciation, depletion and amortization	1,606	1,397	1,289
Other taxes	575	581	519
Total operating expenses	13,137	15,538	11,192
Income from operations	3,345	2,433	2,737
Other income	174	168	167
Interest and related charges:			
Interest expense	890	844	798
Interest expense—junior subordinated notes payable ⁽¹⁾	124	106	112
Subsidiary preferred dividends	16	16	16
Total interest and related charges	1,030	966	926
Income from continuing operations before income tax expense	2,489	1,635	1,978
Income tax expense	920	588	705
Minority interest	6	—	—
Income from continuing operations before cumulative effect of change in accounting principle	1,563	1,047	1,273
Loss from discontinued operations (net of income tax benefit of \$100, \$2 and \$10 in 2006, 2005 and 2004, respectively)	(183)	(8)	(24)
Cumulative effect of change in accounting principle (net of income tax benefit of \$4)	—	(6)	—
Net Income	\$ 1,380	\$ 1,033	\$ 1,249
Earnings Per Common Share—Basic:			
Income from continuing operations before cumulative effect of change in accounting principle	\$ 4.47	\$ 3.06	\$ 3.87
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle	—	(0.02)	—
Net income	\$ 3.95	\$ 3.02	\$ 3.80
Earnings Per Common Share—Diluted:			
Income from continuing operations before cumulative effect of change in accounting principle	\$ 4.45	\$ 3.04	\$ 3.85
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle	—	(0.02)	—
Net income	\$ 3.93	\$ 3.00	\$ 3.78
Dividends paid per common share	\$ 2.76	\$ 2.68	\$ 2.60

(1) Includes \$104 million, \$106 million and \$112 million payable to affiliated trusts at December 31, 2006, 2005 and 2004, respectively.

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

CONSOLIDATED BALANCE SHEETS

At December 31,	2006	2005
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 138	\$ 146
Customer receivables (less allowance for doubtful accounts of \$26 and \$38)	2,395	3,335
Other receivables (less allowance for doubtful accounts of \$13 and \$9)	358	226
Inventories:		
Materials and supplies	429	392
Fossil fuel	383	314
Gas stored	289	461
Derivative assets	1,593	3,429
Assets held for sale	1,391	4
Deferred income taxes	310	928
Prepayments	254	161
Other	558	733
Total current assets	8,098	10,129
Investments		
Nuclear decommissioning trust funds	2,791	2,534
Available-for-sale securities	39	287
Loans receivable, net	399	31
Other	596	649
Total investments	3,825	3,501
Property, Plant and Equipment		
Property, plant and equipment	43,575	42,063
Accumulated depreciation, depletion and amortization	(14,193)	(13,123)
Total property, plant and equipment, net	29,382	28,940
Deferred Charges and Other Assets		
Goodwill	4,298	4,298
Pension and other postretirement benefit assets	1,246	1,915
Derivative assets	642	1,915
Intangible assets	628	619
Regulatory assets	539	758
Other	611	585
Total deferred charges and other assets	7,964	10,090
Total assets	\$ 49,269	\$ 52,660

At December 31,	2006	2005
(millions)		
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year	\$ 2,478	\$ 2,330
Short-term debt	2,332	1,618
Accounts payable	2,142	2,756
Accrued interest, payroll and taxes	759	694
Derivative liabilities	2,276	6,087
Liabilities held for sale	497	—
Other	745	995
Total current liabilities	11,229	14,480
Long-Term Debt		
Long-term debt	12,842	13,237
Junior subordinated notes payable to:		
Affiliates	1,151	1,416
Other	798	—
Total long-term debt	14,791	14,653
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	5,858	4,984
Asset retirement obligations	1,930	2,249
Derivative liabilities	681	3,971
Regulatory liabilities	614	607
Other	973	1,062
Total deferred credits and other liabilities	10,056	12,873
Total liabilities	36,076	42,006
Commitments and Contingencies (see Note 23)		
Minority Interest	23	—
Subsidiary Preferred Stock Not Subject To Mandatory Redemption	257	257
Common Shareholders' Equity		
Common stock—no par ⁽¹⁾	11,250	11,286
Other paid-in capital	128	125
Retained earnings	1,960	1,550
Accumulated other comprehensive loss	(425)	(2,564)
Total common shareholders' equity	12,913	10,397
Total liabilities and shareholders' equity	\$49,269	\$52,660

(1) 500 million shares authorized; 349 million shares and 347 million shares outstanding at December 31, 2006 and December 31, 2005, respectively.

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock		Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
(millions)						
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)
Net 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)
Net 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
Comprehensive income:						
Net income				1,380		1,380
Net deferred derivative gains—hedging activities, net of \$625 tax expense					1,173	1,173
Unrealized gains on investment securities, net of \$83 tax expense					126	126
Minimum pension liability adjustment, net of \$7 tax expense					10	10
Foreign currency translation adjustments					(8)	(8)
Amounts reclassified to net income:						
Net realized gains on investment securities, net of \$6 tax expense					(9)	(9)
Net derivative losses—hedging activities, net of \$724 tax benefit					1,182	1,182
Total comprehensive income				1,380	2,474	3,854
Issuance of stock—employee and direct stock purchase plans	1	95				95
Stock awards and stock options exercised (net of change in unearned compensation)	2	79				79
Issuance of stock—equity-linked securities	4	330				330
Stock repurchase and retirement	(5)	(540)				(540)
Tax benefit from stock awards and stock options exercised			8			8
Adjustment to initially adopt SFAS No. 158, net of \$239 tax benefit					(335)	(335)
Dividends and other adjustments			(5)	(970)		(975)
Balance at December 31, 2006	349	\$11,250	\$128	\$1,960	\$(425)	\$12,913

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	2006	2005	2004
(millions)			
Operating Activities			
Net income	\$ 1,380	\$ 1,033	\$ 1,249
Adjustments to reconcile net income to net cash from operating activities:			
Impairment of merchant generation peaking facilities	253	—	—
Dominion Capital, Inc. impairment losses	89	35	72
Charges related to pending sale of gas distribution subsidiaries	188	—	—
Net realized and unrealized derivative (gains)/losses	(242)	335	(63)
Depreciation, depletion and amortization	1,739	1,538	1,433
Deferred income taxes and investment tax credits, net	510	64	554
Gain on sale of emissions allowances	(74)	(139)	(35)
Other adjustments to net income	(31)	84	(59)
Changes in:			
Accounts receivable	684	(791)	(288)
Inventories	3	(220)	(30)
Deferred fuel and purchased gas costs, net	239	(57)	89
Pension and other postretirement benefit assets	52	31	(8)
Accounts payable	(526)	686	27
Accrued interest, payroll and taxes	92	147	(9)
Deferred revenue	(262)	(323)	(223)
Margin deposit assets and liabilities	(7)	124	(6)
Other operating assets and liabilities	(82)	76	67
Net cash provided by operating activities	4,005	2,623	2,770
Investing Activities			
Plant construction and other property additions	(1,995)	(1,683)	(1,451)
Additions to gas and oil properties, including acquisitions	(2,057)	(1,675)	(1,299)
Proceeds from sales of gas and oil properties	393	595	729
Acquisition of businesses	(91)	(877)	—
Proceeds from sales of securities and loan receivable collections and payoffs	1,110	754	466
Purchases of securities and loan receivable originations	(1,196)	(854)	(490)
Proceeds from sale of emissions allowances	76	234	41
Net proceeds from sale or disposal of other assets and investments	150	17	23
Advances to lessor for project under construction	—	—	(132)
Reimbursement from lessor for project under construction	—	—	806
Other	116	129	92
Net cash used in investing activities	(3,494)	(3,360)	(1,215)
Financing Activities			
Issuance (repayment) of short-term debt, net	713	1,045	(879)
Issuance of long-term debt	2,450	2,300	877
Repayment of long-term debt	(2,333)	(2,237)	(1,283)
Repayment of notes payable to affiliate	(300)	—	—
Issuance of common stock	479	664	839
Repurchase of common stock	(540)	(276)	—
Common dividend payments	(970)	(923)	(861)
Other	(14)	(51)	(13)
Net cash provided by (used in) financing activities	(515)	522	(1,320)
Increase (decrease) in cash and cash equivalents	(4)	(215)	235
Cash and cash equivalents at beginning of year	146	361	126
Cash and cash equivalents at end of year ⁽¹⁾	\$ 142	\$ 146	\$ 361
Supplemental Cash Flow Information:			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	\$ 920	\$ 1,007	\$ 926
Income taxes	432	399	(8)
Noncash investing and financing activities:			
Accrued capital expenditures	258	220	111
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

(1) 2006 amount includes \$4 million of cash classified as held for sale in our Consolidated Balance Sheet.

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 for sale in Virginia and north-eastern 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. In 2005, Virginia Power became a member of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO) and integrated its electric transmission facilities into PJM wholesale electricity markets.

CNG operates in all phases of the natural gas business, explores for and produces 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 1.5 million residential, small commercial and industrial customer accounts in the Northeast, Mid-Atlantic and Midwest regions of the United States (U.S.). CNG also operates an interstate gas transmission pipeline and underground natural gas storage system and gathering and extraction facilities in the Northeast, Mid-Atlantic and Midwest states 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 (E&P) operations are located in several major gas and oil producing basins in the U.S., both onshore and offshore.

DEI is involved in merchant generation, energy marketing and price risk management activities and natural gas and oil exploration and production in the U.S. and Canada.

VPEM provides fuel and price risk management services to 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 E&P. In addition, we report a Corporate segment that includes our corporate, service company and other functions. 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 (GAAP). These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the periods presented. Actual results may differ from those estimates.

Our Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of 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 2005 and 2004 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2006 presentation.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Our customer receivables at December 31, 2006 and 2005 included \$267 million and \$396 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity 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 are as follows:

- **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 and sales activity related to agreements used to facilitate the marketing of gas production (buy/sell arrangements) described in Note 3;
- **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 3;
- **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** revenue is recognized based on actual volumes of gas and oil sold to purchasers. Sales require delivery of the product to the purchaser, passage of title and probability of collection of purchaser amounts owed. Gas and oil production revenue includes sales of Company produced gas, oil, condensate and 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. We use the sales method of accounting for gas imbalances. An imbalance is created when Company volumes of gas sold pertaining to a property do not equate to the volumes to which we are entitled based on our interest in the property. A liability is recognized when our excess sales over entitled volumes exceeds our net remaining property reserves; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations; gas and oil processing and handling revenue; revenues from DCI operations; and business interruption insurance revenue associated with delayed gas and oil production caused by hurricanes.

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 related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery of fuel rate revenue in excess of current period expenses is recognized as a regulatory liability.

For electric fuel and purchased energy expenses, effective January 1, 2004, the fuel factor provisions for our Virginia retail customers were locked in until July 1, 2007. Effective July 1, 2007 the fuel factor will be adjusted as discussed under *Virginia Fuel Expenses* in Note 23. Approximately 7.5% of the cost of fuel used in electric generation and energy purchases used to serve utility customers is currently subject to deferral accounting. Deferred costs associated with the Virginia jurisdictional portion of expenditures incurred through 2003 continue to be reported as a regulatory asset, which is expected to be recovered by July 1, 2007.

Income Taxes

We file a consolidated federal income tax return 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

Effective January 1, 2006, we measure and recognize compensation expense in accordance with SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123R), which requires that compensation expense relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. We adopted SFAS No. 123R using the modified prospective application transition method. Under this transition method, compensation cost is 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, *Accounting for Stock-Based Compensation*, for all awards granted prior to January 1, 2006, but not vested as of that date. Results for prior periods were not restated.

Prior to January 1, 2006, we accounted for our stock-based compensation plans under the measurement and recognition provisions of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under this method, stock option awards generally did not result in compensation expense, since their exercise price was typically equal to the market price of our common stock on the date of grant. Accordingly, stock-based compensation expense was included as a pro forma disclosure in the footnotes to our financial statements.

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 to stock-based employee compensation:

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

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

Prior to the adoption of SFAS No. 123R, we presented the benefits of tax deductions resulting from the exercise of stock-based compensation as an operating cash flow in our Consolidated Statements of Cash Flows. SFAS No. 123R requires the benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation (excess tax benefits) to be classified as a financing cash flow. In accordance with FASB Staff Position No. FAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, we have elected to use the simplified method to determine the impact of employee stock option awards that were fully vested and outstanding upon the adoption of SFAS No. 123R. During the year ended December 31, 2006, we realized \$1 million of excess tax benefits from restricted stock awards that vested during 2006 and \$7 million of tax benefits related to the exercise of employee stock

option awards that were fully vested at December 31, 2005. Such amounts are reported as a financing cash flow.

Restricted stock awards granted prior to January 1, 2006 contain terms that accelerate vesting upon retirement. Our previous practice was to recognize compensation cost for these awards over the stated vesting term unless vesting was actually accelerated by retirement. Following our adoption of SFAS No. 123R, we continue to recognize compensation cost over the stated vesting term for existing restricted stock awards, but we are now required to recognize compensation cost over the shorter of: (1) the stated vesting term or (2) the period from the date of grant to the date of retirement eligibility for newly issued or modified restricted stock awards with similar terms. In the year ended December 31, 2006, we recognized approximately \$5 million of compensation cost related to awards previously granted to retirement eligible employees. At December 31, 2006, unrecognized compensation cost for restricted stock awards held by retirement eligible employees totaled approximately \$5 million.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. At December 31, 2006 and 2005, accounts payable included \$125 million and \$150 million, respectively, of checks outstanding but not yet presented for payment. For purposes of our Consolidated Statements of Cash Flows, we consider cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

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 \$8 million at December 31, 2006 and \$128 million at December 31, 2005. The decrease in inventory from 2005 to 2006 reflects the sale of gas inventory at The East Ohio Gas Company and the reclassification of the inventory of The Peoples Natural Gas Company (Peoples) and Hope Gas, Inc. (Hope) to assets held for sale. Based on the average price of gas purchased during 2006, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by approximately \$211 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 physical 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 at period end, subject to the terms of our tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to us from other parties are reported in other current assets and imbalances that we owe to other parties are reported in other current liabilities in our Consolidated Balance Sheets.

Derivative Instruments

We use derivative instruments such as futures, swaps, forwards, options and financial transmission rights to manage the commod-

ity, 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 in our Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting—normal purchases and normal sales—may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

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

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

DERIVATIVE INSTRUMENTS DESIGNATED AS HEDGING INSTRUMENTS

We designate a substantial portion of our derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, we formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. We assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing

basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, we may elect to exclude certain gains or losses on hedging instruments from the measurement of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. We discontinue hedge accounting prospectively for derivatives that cease to be highly effective hedges.

Cash Flow Hedges—A 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, oil and other energy-related products. We also use foreign currency forward contracts to hedge the variability in foreign exchange rates and interest rate swaps to hedge our exposure to variable interest rates on long-term debt. For transactions in which we are hedging the variability of cash flows, changes in the fair value of the derivative are reported in 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 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 gen-

erally 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 other income and unrealized gains and losses reported as a component of AOCI, net of tax.

We analyze all securities classified as available-for-sale to determine whether a decline in fair value should be considered other than temporary. We use several criteria to evaluate other-than-temporary declines, including the length of time over which the market value has been lower than its cost, the percentage of the decline as compared to its cost and the expected fair value of the security. In addition, retained interests from securitizations of financial assets are first 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*. If a decline in fair value of any security is determined to be other than temporary, the security is written down to its fair value at the end of the reporting period.

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

Property, Plant and Equipment

Property, plant and equipment, including additions and replacements, is recorded at original cost, including labor, materials, asset retirement costs and other direct and indirect costs including capitalized interest. The cost of repairs and maintenance, including minor additions and replacements, is charged to expense as it is incurred. In 2006, 2005 and 2004, we capitalized interest costs

of \$120 million, \$99 million and \$70 million, respectively. In 2006, 2005 and 2004, for electric distribution, electric transmission and natural gas property subject to cost-of-service utility rate regulation, we capitalized an allowance for funds used during construction of \$14 million, \$4 million and \$4 million, respectively.

For electric distribution, electric transmission 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 net book value at the retirement date.

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

	2006	2005	2004
(percent)			
Generation	2.07	2.04	1.97
Transmission	2.28	2.25	2.21
Distribution	3.28	3.19	3.19
Storage	3.10	3.15	3.04
Gas gathering and processing	2.05	2.21	2.31
General and other	5.22	5.80	6.03

Our nonutility property, plant and equipment, excluding E&P 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 – 40 years
General and other	3 – 25 years

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

We follow the full cost method of accounting for gas and oil E&P 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 8% 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, 2006. Future cash flows associated with settling AROs that have been accrued in 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.

Depletion of gas and oil producing properties is computed using the units-of-production method. Under the full cost method, the depletable base of costs subject to depletion 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 including associated exploration-related costs are initially excluded from the depletable base. Until the properties are evaluated, a ratable portion of the capitalized costs is periodically reclassified to the depletable 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 depletable 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 (SO₂) 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 energy marketing operations are held for the purpose of resale to third parties.

ALLOWANCES HELD FOR CONSUMPTION

Allowances held for consumption are classified as intangible assets in our Consolidated Balance Sheets. Carrying amounts are based on our cost to acquire the allowances or, in the case of a business combination, on 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 in our Consolidated Statements of Income. We report purchases and sales of these allowances as investing activities in our Consolidated Statements of Cash Flows and gains or losses resulting from sales in other operations and maintenance expense in our Consolidated Statements of Income.

ALLOWANCES HELD FOR RESALE

Allowances held for resale are classified as materials and supplies inventory in our Consolidated Balance Sheets and valued at the lower of cost or market.

These allowances are not consumed and therefore are not subject to amortization. We report purchases and sales of these allowances as operating activities in 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 in our Consolidated Statements of Income.

Goodwill and Intangible Assets

We evaluate goodwill for impairment annually, as of April 1, 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. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount.

Regulatory Assets and Liabilities

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

Asset Retirement Obligations

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

Amortization of Debt Issuance Costs

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

NOTE 3. NEWLY ADOPTED ACCOUNTING STANDARDS

2006

SFAS 123R

Effective January 1, 2006, we adopted SFAS No. 123R which requires that compensation expense relating to share-based pay-

ment 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 plans, performance-based awards, share appreciation rights and employee share purchase plans. We adopted SFAS No. 123R using the modified prospective application transition method. Under this transition method, compensation cost is 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 that date. Accordingly, results for prior periods were not restated.

SFAS NO. 158

Effective December 31, 2006, we adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of its defined benefit pension and other postretirement benefit plans as an asset or liability, respectively, in its balance sheet and to recognize changes in the funded status as a component of other comprehensive income in the year in which the changes occur. The funded status is measured as the difference between the fair value of a plan's assets and the benefit obligation. In addition, SFAS No. 158 requires an employer to measure benefit plan assets and obligations that determine the funded status of a plan as of the end of the employer's fiscal year, which we already do.

Our adoption of SFAS No. 158 had no impact on our results of operations or cash flows and it will not affect our operating results or cash flows in future periods. The following table illustrates the incremental effect of adopting the provisions of SFAS No. 158 on our Consolidated Balance Sheet at December 31, 2006:

	Prior to adopting SFAS No. 158	Effect of Adopting SFAS No. 158	As Reported at December 31, 2006
(millions)			
Assets:			
Pension and other postretirement benefit assets	\$1,858	\$(612)	\$1,246
Regulatory assets	404	135	539
Liabilities:			
Other current liabilities	743	2	745
Deferred income taxes and investment tax credits	6,097	(239)	5,858
Regulatory liabilities	601	13	614
Other deferred credits and other liabilities	891	82	973
Shareholders' Equity:			
Accumulated other comprehensive loss	(90)	(335)	(425)

Upon adoption, we recorded regulatory assets (liabilities), rather than an adjustment to AOCI, for previously unrecognized pension and other postretirement benefit costs (credits) expected to be recovered (refunded) through future rates by certain of our rate-regulated subsidiaries. The adjustments to AOCI, regulatory assets and regulatory liabilities at adoption of SFAS No. 158 represent the net unrecognized actuarial gains (losses), unrecognized prior service cost (credit) and unrecognized transition obligation remaining from our initial adoption of SFAS No. 106,

Employers' Accounting for Postretirement Benefits Other Than Pensions, all of which were previously netted against the funded status of our plans in our Consolidated Balance Sheet. The amounts in AOCI, regulatory assets and regulatory liabilities will be subsequently recognized as a component of net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic benefit cost (credit) in the same periods will be recognized as a component of other comprehensive income (loss) or regulatory assets or regulatory liabilities as appropriate. Those amounts will be subsequently recognized as a component of net periodic benefit cost (credit) on the same basis as the amounts recognized in AOCI, regulatory assets and regulatory liabilities at adoption of SFAS No. 158.

SAB 108

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

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 onshore marketing locations and to facilitate gas transportation. In September 2005, the Financial Accounting Standards Board (FASB) ratified the EITF's consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, which requires buy/sell and related agreements to be presented on a net basis in our Consolidated Statements of Income if they are entered into in contemplation of one another. We adopted the provisions of EITF 04-13 on April 1, 2006 for new arrangements and modifications or renewals of existing arrangements made after that date. As a result, a significant portion of our activity related to buy/sell arrangements is presented on a net basis in our Consolidated Statement of Income for 2006; however, there was no impact on our results of operations or cash flows. Pursuant to the transition provisions of EITF 04-13, activity related to buy/sell arrangements that were entered into prior to April 1, 2006 and have not been modified or renewed after that date continue to be reported on a gross basis and are summarized below:

	2006	2005	2004
(millions)			
Sale activity included in operating revenue	\$576	\$623	\$436
Purchase activity included in operating expenses ⁽¹⁾	578	651	440

(1) Included in other energy-related commodity purchases expense and purchased gas expense in our Consolidated Statements of Income.

2005

FIN 47

We adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47) on December 31, 2005. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional 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, 2004:

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

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

2004

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 change 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 aver-

age 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.

NOTE 4. RECENTLY ISSUED ACCOUNTING STANDARDS

FIN 48

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FIN 48 establishes standards for recognition and measurement, in the financial statements, of positions taken, or expected to be taken, by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in its financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

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

With the adoption of FIN 48, we estimate that the cumulative effect of the change in accounting principle will reduce the beginning balance of our retained earnings as of January 1, 2007 by between \$35 million and \$75 million.

SFAS NO. 155

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that would otherwise require bifurcation. Our adoption of SFAS No. 155 on January 1, 2007 will have no impact on our results of operations or financial condition.

SFAS NO. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability and establishes a fair value hierarchy of three levels that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy. The provisions of SFAS No. 157 will become effective for us beginning January 1, 2008. Generally, the provisions of this statement are to be applied prospectively. Certain situations, however, require retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of

accounting change. Such retrospective application is required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses under EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and SFAS No. 155. We are currently evaluating the impact that SFAS No. 157 will have on our results of operations and financial condition.

SFAS NO. 159

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

NOTE 5. ACQUISITIONS

Pablo Energy LLC

In February 2006, we completed the acquisition of Pablo Energy LLC (Pablo) for approximately \$92 million in cash. Pablo holds producing and other properties located in the Texas Panhandle area. The operations of Pablo are included in our Dominion E&P operating segment.

Kewaunee Power Station

In July 2005, we completed the acquisition of the 556-megawatt (Mw) 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 our Dominion Generation operating segment.

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 Mw Brayton Point Station in Somerset, Massachusetts; the 754 Mw Salem Harbor Station in Salem, Massachusetts; and the 432 Mw Manchester Street Station in Providence, Rhode Island. The operations of Dominion New England are included in our Dominion Generation operating segment.

NOTE 6. OPERATING REVENUE

Our operating revenue consists of the following:

Year Ended December 31,	2006	2005	2004
(millions)			
Electric sales:			
Regulated	\$ 5,451	\$ 5,543	\$ 5,180
Nonregulated	2,528	3,044	1,199
Gas sales:			
Regulated	1,397	1,763	1,422
Nonregulated	2,311	2,942	2,069
Other energy-related commodity sales	1,400	1,672	1,272
Gas transportation and storage	946	902	803
Gas and oil production	1,892	1,704	1,636
Other	557	401	348
Total operating revenue	\$16,482	\$17,971	\$13,929

NOTE 7. INCOME TAXES

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

Year Ended December 31,	2006	2005	2004
(millions)			
Income before provision for taxes:			
U.S.	\$2,465	\$1,606	\$1,952
Non-U.S.	24	29	26
Total	2,489	1,635	1,978
Income tax expense:			
Current			
Federal	195	420	70
State	140	103	80
Non-U.S.	2	—	(3)
Total current	337	523	147
Deferred			
Federal	537	86	576
State	73	(19)	(13)
Non-U.S.	(11)	15	12
Total deferred ⁽¹⁾	599	82	575
Amortization of deferred investment tax credits	(16)	(17)	(17)
Total income tax expense	\$ 920	\$ 588	\$ 705

(1) 2006 includes a decrease of \$163 million in federal and state valuation allowances. Also, includes a \$12 million decrease resulting from the enactment of lower Canadian tax rates.

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

Year Ended December 31,	2006	2005	2004
U.S. statutory rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Recognition of deferred taxes - stock of subsidiaries held for sale	5.8	—	—
State taxes, net of federal benefit	5.7	3.5	1.7
Preferred dividends	0.2	0.3	0.3
Valuation allowances	(6.5)	1.0	0.2
Other benefits and taxes - foreign operations	(0.7)	(0.4)	—
Amortization of investment tax credits	(0.5)	(0.8)	(0.7)
Employee stock ownership plan deduction	(0.5)	(0.8)	(0.5)
Employee pension and other benefits	(0.3)	(1.2)	(0.5)
Other, net	(1.2)	(0.7)	0.1
Effective tax rate	37.0%	35.9%	35.6%

In connection with the pending sale of two of our regulated gas distribution subsidiaries, we established \$145 million of deferred tax liabilities on our Consolidated Balance Sheet in accordance with EITF Issue No. 93-17, *Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary that is Accounted for as a Discontinued Operation* (EITF 93-17). Although these subsidiaries are not classified as discontinued operations, EITF 93-17 requires that the deferred tax impact of the excess of the financial reporting basis over the tax basis of a parent's investment in a subsidiary be recognized when it is apparent that this difference will reverse in the foreseeable future. We recorded a charge since the financial reporting basis of our investment in Peoples and Hope exceeds our tax basis. This difference and related deferred taxes will reverse and will partially offset current tax expense that will be recognized upon closing of the sale.

In addition, for the year ended December 31, 2006, the reduction in valuation allowances reflects the expected utilization of federal and state capital loss carryforwards to offset capital gain income that is expected to be generated from the pending sale of the two subsidiaries, partially offset by valuation allowance increases primarily associated with deferred tax assets recognized as a result of impairments of certain DCI investments discussed in Note 27.

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

As of December 31,	2006	2005
(millions)		
Deferred income taxes:		
Total deferred income tax assets	\$1,406	\$ 2,703
Total deferred income tax liabilities	6,918	6,701
Total net deferred income tax liabilities	\$5,512	\$ 3,998
Total deferred income taxes:		
Depreciation method and plant basis differences	\$2,878	\$ 2,798
Gas and oil exploration and production related differences	2,186	1,956
Deferred state income taxes	514	268
Pension benefits	431	672
Unrealized gains - available for sale securities	151	89
Recognition of deferred taxes - stock of subsidiaries held for sale	145	—
Partnership basis differences	54	181
Loss and credit carryforwards	(762)	(893)
Derivative losses	(174)	(1,495)
Valuation allowances	144	339
Other	(55)	83
Total net deferred income tax liabilities	\$5,512	\$ 3,998

At December 31, 2006, we had the following loss and credit carryforwards:

- Federal loss carryforwards of \$845 million that expire if unutilized during the period 2007 through 2021. A valuation allowance on \$213 million of carryforwards has been established due to the uncertainty of realizing these future deductions;
- State loss carryforwards of \$2.2 billion that expire if unutilized during the period 2007 through 2026. A valuation allowance on \$769 million of these carryforwards has been established; and
- Federal and state minimum tax credits of \$368 million that do not expire and other federal and state income tax credits of \$68 million that will expire if unutilized during the period 2011 through 2025.

Other

We have not provided for U.S. deferred income taxes or foreign withholding taxes on remaining undistributed earnings of \$178 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. This deduction reduced our 2005 income tax payments by approximately \$116 million. If our tax deduction is challenged and ultimately not sustained, we will have to pay \$116 million plus accrued interest. In addition, we have recorded an estimated liability of \$27 million for reduced payments to a state taxing

authority related to certain tax credits, for which the tax benefit has not yet been recognized. At December 31, 2006 and December 31, 2005, our Consolidated Balance Sheets reflect \$187 million and \$144 million, respectively, of income tax-related contingent liabilities.

American Jobs Creation Act of 2004 (the Act)

The Act has several provisions for energy companies, including a deduction related to taxable income derived from qualified production activities. Our electric generation and oil and gas extraction activities qualify as production activities under the Act. The Act limits the deduction to the lesser of taxable income derived from qualified production activities or our consolidated federal taxable income. Our qualified production activities deduction for 2006 is minimal.

NOTE 8. HEDGE ACCOUNTING ACTIVITIES

We are exposed to the impact of market fluctuations in the price of natural gas, oil, 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,	2006	2005	2004
(millions)			
Portion of gains (losses) on hedging instruments determined to be ineffective and included in net income:			
Fair value hedges	\$(22)	\$ 18	\$ (2)
Cash flow hedges ⁽¹⁾	44	(79)	10
Net ineffectiveness	\$ 22	\$(61)	\$ 8
Portion of gains (losses) on hedging instruments excluded from measurement of effectiveness and included in net income:			
Fair value hedges ⁽²⁾	\$ 8	\$ 4	\$ 3
Cash flow hedges ⁽³⁾	(1)	(2)	101
Total	\$ 7	\$ 2	\$104

(1) Represents hedge ineffectiveness, primarily due to changes in the fair value differential between the delivery location and commodity specifications of derivatives held by our E&P 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.

(3) Amounts relate to changes in options' time value.

Due to interruptions in oil production in the Gulf of Mexico 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 (\$45 million after-tax) of 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. The discontinuance of hedge accounting for these contracts resulted in the reclassification of \$30 million (\$19 million after-tax) of losses from AOCI to earnings in March 2005.

Additionally, due to interruptions in gas and oil production in the Gulf of Mexico and southern Louisiana caused by Hurricanes Katrina and Rita (2005 hurricanes), 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.

In June 2006, we recorded a \$60 million (\$37 million after-tax) charge eliminating the application of hedge accounting for certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts that sold trust preferred securities. Prior to June 30, 2006, we applied the shortcut method of fair value hedge accounting under SFAS No. 133 to these swaps, allowing us to assume no hedge ineffectiveness for these derivatives. We determined that these swaps did not qualify for the shortcut method because of an interest deferral mechanism within the junior subordinated notes and they could not qualify for hedge accounting retrospectively because the hedge documentation required for the long-haul method was not in place at the inception of the hedge. These instruments were and we believed would continue to be highly effective economic hedges. We re-designated the interest rate swaps associated with these transactions as fair value hedges under the long-haul accounting method in order to qualify them prospectively for fair value hedge accounting under SFAS No. 133. Losses related to the discontinuance of hedge accounting are reported in other operations and maintenance expense in our Consolidated Statements of Income.

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

	AOCI After Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months After Tax	Maximum Term
(millions)			
Commodities:			
Gas	\$(115)	\$(159)	51 months
Oil	(253)	(196)	36 months
Electricity	(46)	(65)	36 months
Interest rate	(26)	—	234 months
Foreign currency	18	9	9 months
Total	\$(422)	\$(411)	

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.

NOTE 9. DISPOSITIONS

Sale of Merchant Generation Facilities

In December 2006, we reached an agreement with an entity jointly owned by Tenaska Power Fund, L.P. and Warburg Pincus LLC to sell three of our natural gas-fired merchant generation peaking facilities (Peaker facilities). Peaking facilities are used during times of high electricity demand, generally in the summer months. The Peaker facilities are:

- Armstrong, a 625 Mw station in Shelocta, Pennsylvania;
- Troy, a 600 Mw station in Luckey, Ohio; and
- Pleasants, a 313 Mw station in St. Mary's, West Virginia.

The sale is expected to result in proceeds of approximately \$256 million and should close by the end of the first quarter of 2007, pending regulatory approval by the Federal Energy Regulatory Commission (FERC). We have obtained approval from the Federal Trade Commission. No state regulatory approvals are required.

We offered the facilities for sale following a review of our portfolio of assets. We classified these assets as held for sale during the fourth quarter of 2006 and adjusted their carrying amounts to fair value less cost to sell, resulting in an impairment charge of \$253 million (\$164 million after-tax).

The carrying amounts of the major classes of assets and liabilities classified as held for sale in our Consolidated Balance Sheet are comprised of property, plant and equipment, net (\$245 million), inventory (\$13 million) and accounts payable (\$3 million).

The following table presents selected information regarding the results of operations of the Peaker facilities, which are reported as discontinued operations in our Consolidated Statements of Income:

December 31,	2006	2005	2004
(millions)			
Operating Revenue	\$ 42	\$ 71	\$ 62
Loss before income taxes	(283)	(19)	(14)

The Peaker facilities' operating revenues were related to sales to other Dominion affiliates. In addition, the Peaker facilities purchased \$14 million, \$38 million and \$34 million of electric fuel from affiliates in 2006, 2005 and 2004, respectively.

Sale of Regulated Gas Distribution Subsidiaries

On March 1, 2006, we entered into an agreement with Equitable Resources, Inc., to sell two of our wholly-owned regulated gas distribution subsidiaries, Peoples and Hope, for approximately \$970 million plus adjustments to reflect capital expenditures and changes in working capital. Peoples and Hope serve approximately 500,000 customer accounts in Pennsylvania and West Virginia. The transaction is expected to close by the end of the second 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 classified as held for sale in our Consolidated Balance Sheet are as follows:

At December 31,	2006
(millions)	
ASSETS	
Current Assets	
Cash	\$ 4
Customer accounts receivable	144
Unrecovered gas costs	31
Other	90
Total current assets	269
Investments	2
Property, Plant and Equipment	
Property, plant and equipment	1,129
Accumulated depreciation, depletion and amortization	(375)
Total property, plant and equipment, net	754
Deferred Charges and Other Assets	
Regulatory assets	106
Other	2
Total deferred charges and other assets	108
Assets held for sale	\$1,133
LIABILITIES	
Current Liabilities	
Accounts payable	\$ 90
Payables to affiliates	40
Accrued taxes	23
Deferred income taxes	9
Other	74
Total current liabilities	236
Deferred Credits and Other Liabilities	
Asset retirement obligations	38
Deferred income taxes and investment tax credits	187
Regulatory liabilities	26
Other	7
Total deferred credits and other liabilities	258
Liabilities held for sale	\$ 494

The following table presents selected information regarding the results of operations of Peoples and Hope:

December 31,	2006	2005	2004
(millions)			
Operating Revenue	\$ 699	\$742	\$617
Income (loss) before income taxes	(112)	54	71

During 2006, we recognized a \$166 million (\$104 million after-tax) charge, recorded in other operations and maintenance expense in our Consolidated Statement of Income, resulting from the write-off of certain regulatory assets related to the pending sale

of Peoples and Hope, since the recovery of those assets is no longer probable. We also established \$145 million of deferred tax liabilities in our Consolidated Balance Sheet in accordance with EITF 93-17.

EITF Issue No. 03-13, *Applying the Conditions of Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations* (EITF 03-13), provides that the results of operations of a component of an entity that has been disposed of or is classified as held for sale shall be reported in discontinued operations if both of the following conditions are met: (a) the operations and cash flows of the components have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction and (b) the entity will not have any significant continuing involvement in the operations of the component after the disposal transaction. While we do not expect to have significant continuing involvement with Peoples or Hope after their disposal, we do expect to have continuing cash flows related primarily to our sale to them of natural gas production from our Appalachian E&P operations, as well as natural gas transportation and storage services provided to them by our gas transmission operations. Due to these expected significant continuing cash flows, the results of Peoples and Hope have not been reported as discontinued operations in our Consolidated Statements of Income. We will continue to assess the level of our involvement and continuing cash flows with Peoples and Hope for one year after the date of sale in accordance with EITF 03-13, and if circumstances change, we may be required to reclassify the results of Peoples and Hope as discontinued operations in our Consolidated Statements of Income.

Discontinued Operations—Telecommunications Operations

Dominion Fiber Ventures, LLC 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 region of the U.S. 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 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). 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 outstanding guarantee, we have several potential indemnification obligations related to our discontinued telecommunications operations.

NOTE 10. EARNINGS PER SHARE

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

Year Ended December 31,	2006	2005	2004
(millions, except per share amounts)			
Income from continuing operations before cumulative effect of change in accounting principle	\$1,563	\$1,047	\$1,273
Loss from discontinued operations	(183)	(8)	(24)
Cumulative effect of change in accounting principle	—	(6)	—
Net income	\$1,380	\$1,033	\$1,249
Basic EPS			
Average shares of common stock outstanding—basic	349.7	342.3	329.1
Income from continuing operations before cumulative effect of change in accounting principle	\$ 4.47	\$ 3.06	\$ 3.87
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle	—	(0.02)	—
Net income	\$ 3.95	\$ 3.02	\$ 3.80
Diluted EPS			
Average shares of common stock outstanding	349.7	342.3	329.1
Net effect of potentially dilutive securities ⁽¹⁾	1.9	2.1	1.4
Average shares of common stock outstanding—diluted	351.6	344.4	330.5
Income from continuing operations before cumulative effect of change in accounting principle	\$ 4.45	\$ 3.04	\$ 3.85
Loss from discontinued operations	(0.52)	(0.02)	(0.07)
Cumulative effect of change in accounting principle	—	(0.02)	—
Net income	\$ 3.93	\$ 3.00	\$ 3.78

(1) Potentially dilutive securities consist of options, restricted stock, equity-linked securities and contingently convertible senior notes. 2005 and 2004 potentially dilutive securities also included shares that were issuable under a forward equity sale agreement.

Potentially dilutive securities with the right to purchase approximately 1 million, 3 million and 5 million average common shares for the years ended December 31, 2006, 2005 and 2004, 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, 2006 and 2005 are summarized below:

	Fair Value	Total Unrealized Gains Included in AOCI	Total Unrealized Losses Included in AOCI
(millions)			
2006			
Equity securities	\$1,753	\$456	\$—
Debt securities	1,003	15	—
Total	\$2,756	\$471	\$—
2005			
Equity securities	\$1,598	\$296	\$25
Debt securities	1,157	11	8
Total	\$2,755	\$307	\$33

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 were in a continuous loss position, at December 31, 2005:

	Equity Securities		Debt Securities	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
(millions)				
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, 2006, these debt securities totaled \$38 million. The fair value of all other debt securities at December 31, 2006 by contractual maturity are as follows:

	Amount
(millions)	
Due in one year or less	\$ 47
Due after one year through five years	280
Due after five years through ten years	305
Due after ten years	333
Total	\$965

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,	2006	2005	2004
(millions)			
Available-for-sale securities:			
Proceeds from sales	\$1,025	\$754	\$463
Realized gains	90	46	57
Realized losses	77	49	90
Trading securities:			
Net unrealized gain	9	6	4

NOTE 12. PROPERTY, PLANT AND EQUIPMENT

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

At December 31,	2006	2005
(millions)		
Utility:		
Generation	\$10,088	\$10,243
Transmission	3,627	3,570
Distribution	7,944	8,408
Storage	1,109	947
Nuclear fuel	907	870
Gas gathering and processing	433	433
General and other	735	736
Plant under construction	1,136	954
Total utility	25,979	26,161
Nonutility:		
Exploration and production properties being amortized:		
Proved	11,747	9,929
Unproved	913	753
Unproved exploration and production properties not being amortized	1,067	1,022
Merchant generation—nuclear	1,034	1,109
Merchant generation—other	1,311	1,612
Nuclear fuel	441	361
Other—including plant under construction	1,083	1,116
Total nonutility	17,596	15,902
Total property, plant and equipment	\$43,575	\$42,063

Costs of unproved properties capitalized under the full cost method of accounting that were excluded from amortization at December 31, 2006 and the years in which such excluded costs were incurred, are as follows:

	Total	2006	2005	2004	Years Prior
(millions)					
Property acquisition costs	\$ 573	\$135	\$ 61	\$17	\$360
Exploration costs	335	184	73	32	46
Capitalized interest	159	36	29	24	70
Total	\$1,067	\$355	\$163	\$73	\$476

There were no significant properties under development, as defined by the SEC, excluded from amortization at December 31, 2006. 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 U.S. and Canadian cost centers were as follows:

Year Ended December 31,	2006	2005	2004
(Per Mcf Equivalent)			
U.S. cost center	\$1.65	\$1.41	\$1.28
Canadian cost center	2.19	1.82	1.18

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 recognize revenue 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. The remaining deferred revenue amounts were \$248 million and \$510 million at December 31, 2006 and 2005, respectively.

Sale of E&P Properties

In 2006, we received approximately \$393 million of proceeds from the sale of gas and oil properties, primarily resulting from the fourth quarter sale of certain properties located in Texas and New Mexico. The proceeds were credited to our U.S. full cost pool.

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 Power Stations

Our proportionate share of jointly-owned power stations at December 31, 2006 is as follows:

	Bath County Pumped Storage Station	North Anna Power Station	Clover Power Station	Millstone Power Station ⁽¹⁾
(millions, except percentages)				
Ownership interest	60.0%	88.4%	50.0%	93.5%
Plant in service	\$1,017	\$1,998	\$ 553	\$ 534
Accumulated depreciation	(406)	(964)	(132)	(92)
Nuclear fuel	—	399	—	244
Accumulated amortization of nuclear fuel	—	(331)	—	(159)
Plant under construction	10	63	4	35

(1) Represents our ownership interest in Millstone unit 3.

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 2006 or 2005.

Other Intangible Assets

All of our intangible assets, other than goodwill, are subject to amortization. Amortization expense for intangible assets was \$106 million, \$130 million and \$62 million for 2006, 2005 and 2004, respectively. In 2006, we acquired \$59 million of emissions allowances with an estimated weighted-average amortization period of 3.7 years. The components of our intangible assets are as follows:

At December 31,	2006		2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
(millions)				
Software and software licenses	\$ 642	\$359	\$ 613	\$308
Emissions allowances	177	30	169	50
Other	235	37	225	30
Total	\$1,054	\$426	\$1,007	\$388

Annual amortization expense for intangible assets is estimated to be \$120 million for 2007, \$88 million for 2008, \$74 million for 2009, \$59 million for 2010, and \$29 million for 2011.

NOTE 14. REGULATORY ASSETS AND LIABILITIES

Our regulatory assets and liabilities include the following:

At December 31,	2006	2005
(millions)		
Regulatory assets:		
Unrecovered gas costs	\$ 11	\$179
Regulatory assets—current ⁽¹⁾	11	179
Unrecognized pension and other postretirement benefit costs ⁽²⁾	135	—
Customer bad debts ⁽³⁾	85	70
RTO start-up costs and administration fees ⁽⁴⁾	74	47
Deferred cost of fuel used in electric generation ⁽⁵⁾	72	171
Other postretirement benefit costs ⁽⁶⁾	61	80
Income taxes recoverable through future rates ⁽⁷⁾	46	260
Termination of certain power purchase agreements ⁽⁸⁾	22	24
Other	44	106
Regulatory assets—non-current	539	758
Total regulatory assets	\$550	\$937
Regulatory liabilities:		
Provision for future cost of removal ⁽⁹⁾	577	567
Other ⁽¹⁰⁾	44	48
Total regulatory liabilities	\$621	\$615

- (1) Reported in other current assets.
- (2) Represents unrecognized pension and other postretirement benefit costs expected to be recovered through future rates by certain of our rate-regulated subsidiaries, which were required to be reflected in our Consolidated Balance Sheet upon our adoption of SFAS No. 158.
- (3) 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 \$25 million at December 31, 2006.
- (4) 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 \$64 million in start-up costs and administration fees and \$10 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.
- (5) In connection with the settlement of the 2003 Virginia fuel rate proceeding, we agreed to recover previously incurred costs through June 30, 2007 without a return on a portion of the unrecovered balance. Remaining costs to be recovered totaled \$56 million at December 31, 2006.
- (6) 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.
- (7) Income taxes recoverable through future rates resulting from the recognition of additional deferred income taxes, not recognized under ratemaking practices.
- (8) 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.
- (9) 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.
- (10) Includes \$7 million and \$8 million reported in other current liabilities in 2006 and 2005, respectively.

At December 31, 2006, approximately \$252 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 also be recovered over a 2-year period.

NOTE 15. ASSET RETIREMENT OBLIGATIONS

Our AROs are primarily associated with the decommissioning of our nuclear generation facilities. In addition, our AROs include dismantlement and removal of gas and oil wells and platforms; interim retirements of natural gas gathering, transmission, distribution and storage pipeline components; the retirement of certain nonutility offshore 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 occur when the expected retirement or abandonment dates are determined by our operational planning. The changes to our AROs during 2006 were as follows:

	Amount
(millions)	
Asset retirement obligations at December 31, 2005 ⁽¹⁾	\$2,255
Obligations incurred during the period	12
Obligations settled during the period	(25)
Accretion	109
Revisions in estimated cash flows ⁽²⁾	(384)
Other ⁽³⁾	(35)
Asset retirement obligations at December 31, 2006 ⁽¹⁾	\$1,932

(1) Includes \$6 million and \$2 million reported in other current liabilities at December 31, 2005 and 2006, respectively.

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

(3) Primarily reflects reclassification of Peoples and Hope AROs that are reported in liabilities held for sale.

We have established trusts dedicated to funding the future decommissioning of our nuclear plants. At December 31, 2006 and 2005 the aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled \$2.8 billion and \$2.5 billion, respectively.

NOTE 16. VARIABLE INTEREST ENTITIES

FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, (FIN 46R) addresses the consolidation of VIEs. An entity is considered a VIE under FIN 46R if it does not have sufficient equity to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

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

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

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

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

In February 2006, we restructured three long-term power purchase contracts with two VIEs, of which we are not the primary beneficiary. The restructured contracts expire between 2015 and 2017. Total debt held by the entities is approximately \$299 million. We have remaining purchase commitments with these two VIE supplier entities of \$1 billion at December 31, 2006. We are not subject to any risk of loss from these VIEs, other than the remaining purchase commitments. We paid \$116 million, \$116 million and \$114 million for electric generation capacity and \$55 million, \$57 million and \$47 million for electric energy to these entities for the years ended December 31, 2006, 2005 and 2004, respectively.

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

obligation to the VIEs is to purchase the synthetic fuel that the VIEs produce according to the terms of the applicable purchase contracts.

In September 2006, we, along with three other gas and oil exploration companies, entered into a long-term contract with an unrelated LLC whose only current activities are to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility, to be located in the deepwater Gulf of Mexico. Certain variable pricing terms and guarantees in the contract protect the equity holder from variability, and therefore, the LLC was determined to be a VIE. After completing our FIN 46R analysis, we concluded that although our 25% interest in the contract, as a result of its pricing terms and guarantee, represents a variable interest in the LLC, we are not the primary beneficiary. Our maximum exposure to loss from the contractual arrangement is approximately \$63 million. As of December 31, 2006 we have not made any payments to the LLC.

In June 2006, we entered into a six-month weather derivative contract with a special purpose entity (SPE) that would have provided us cash payments based on the occurrence of specific hurricane-related weather events in the Gulf of Mexico. This weather derivative was executed as an alternative to traditional business interruption insurance. Concurrent with the execution of the weather derivative contract, the SPE issued \$50 million of catastrophe bonds. If specific weather events had occurred, we would have been entitled to proceeds from the SPE of up to \$50 million. As no specific weather events occurred during the term of the contract, which expired December 2006, we did not receive any payments from the SPE. Under the weather derivative contract, we were required to make fixed payments to the SPE, which were used by the SPE to pay a portion of the bond investors' interest payments. We paid approximately \$5.2 million in fixed payments to the SPE for the year ended December 31, 2006. We were also required to reimburse the SPE for certain operating costs, including bond issuance costs and other ongoing fees. We paid \$1.3 million to the SPE for these operating costs in the year ended December 31, 2006. Our FIN 46R analysis determined that the SPE did not have sufficient equity investment at risk, and therefore was a VIE. Furthermore, we concluded that although our interest in the contract represented a variable interest in the SPE, we were not the primary beneficiary. We were not subject to any risk of loss from the contractual arrangement, as our only obligation was to make fixed payments to the SPE and pay certain operating costs of the SPE.

As discussed in Note 27, DCI holds an investment in the subordinated notes of a third-party collateralized debt obligation (CDO) entity. In June 2006, the CDO entity's equity investor withdrew its capital, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R.

Our Consolidated Balance Sheets as of December 31, 2006 and 2005 reflect net property, plant and equipment of \$337 million and \$943 million, respectively, and debt of \$370 million and \$1.1 billion, respectively, related to the consolidation, in accordance with FIN 46R, of certain variable interest lessor entities through which we have financed and leased several power generation projects, as well as our corporate headquarters and aircraft. The debt is non-recourse to us and is secured by the entities' property, plant and equipment. In 2006, the leases on our corporate headquarters and aircraft and three of the power generation facilities terminated. Upon termination of the leases, we took legal title to these assets through repayment of the lessor's related debt. The remaining debt at December 31, 2006, relates to the lease of a power generation facility that terminates in August 2007. We also intend to take legal title to this generation facility through the repayment of the lessor's related debt at the end of the lease term.

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 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. Short-term financing is supported by a \$3.0 billion five-year joint revolving credit facility with Virginia Power and CNG, dated February 2006 that terminates in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Virginia Power, CNG and the Company and other general corporate purposes. This credit facility can also be used to support up to \$1.5 billion of letters of credit.

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

At December 31, 2006 and 2005, total outstanding letters of credit supported by joint credit facilities were \$236 million and \$892 million, respectively.

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

CNG Credit Facilities

Short-term financing at CNG is also supported by an amended and restated \$1.7 billion five-year revolving credit facility dated February 2006 which is scheduled to terminate in August 2010 and a \$1.05 billion 364-day credit facility dated February 2006, which terminated in February 2007, and was not renewed (CNG facilities). These credit facilities support our issuance of commercial paper and letters of credit to provide collateral required by counterparties on derivative financial contracts used in our risk management strategies for our gas and oil production.

At December 31, 2006, there was no outstanding commercial paper supported by the CNG facilities. At December 31, 2005, total outstanding commercial paper supported by the previous credit agreement was \$187 million, with a weighted average interest rate of 4.53%.

At December 31, 2006 and 2005, outstanding letters of credit totaled \$484 million and \$1.23 billion, respectively.

At December 31, 2006, outstanding borrowings under the CNG facilities totaled \$500 million. The funds borrowed were used to repay our \$500 million 2001 Series B 5.375% Senior Notes which matured on November 1, 2006. We expect to repay

the outstanding loan with proceeds received from pending asset sales.

At December 31, 2006 capacity available under the CNG facilities was \$1.77 billion.

CNG has also entered into several bilateral credit facilities in addition to the facilities above in order to provide collateral required on derivative contracts used in our price risk management strategies for gas and oil production operations. At December 31, 2006, CNG had the following letter of credit facilities:

Facility Limit	Outstanding Letters of Credit	Facility Capacity Remaining	Facility Inception Date	Facility Maturity Date
(millions)				
\$100	\$ 25	\$ 75	June 2004	June 2007
100	100	—	August 2004	August 2009
200 ⁽¹⁾	—	200	December 2005	December 2010
\$400	\$125	\$275		

(1) This facility can also be used to support commercial paper borrowings.

NOTE 18. LONG-TERM DEBT

At December 31,	2006 Weighted Average Coupon ⁽¹⁾	2006	2005
(millions, except percentages)			
Dominion Resources, Inc.:			
Unsecured Senior and Medium-Term Notes:			
3.66% to 8.125%, due 2006 to 2010	6.00%	\$ 2,030	\$ 2,112
5.0% to 7.195%, due 2012 to 2035 ⁽²⁾	5.80%	4,130	3,880
Variable rates, due 2006 to 2008	5.44%	1,400	1,100
Unsecured Equity-Linked Senior Notes, 5.75%, due 2008		—	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	8.12%	516	825
Enhanced Junior Subordinated Notes, 6.3% to 7.5%, due 2066	6.75%	800	—
Consolidated Natural Gas Company:			
Secured Bank Debt, Variable rate, due 2006 ⁽⁴⁾		—	234
Unsecured Debentures and Senior Notes:			
5.375% to 6.875%, due 2006 to 2011	6.54%	1,500	2,000
5.0% to 6.875%, due 2013 to 2027	5.89%	1,200	1,200
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, 7.625%, due 2007 ⁽⁵⁾		215	215
Secured Bank Debt, Variable rate, due 2007 ⁽⁴⁾	5.85%	370	370
Unsecured Senior and Medium-Term Notes:			
4.5% to 5.75%, due 2006 to 2010	5.22%	1,000	1,600
4.75% to 8.625%, due 2013 to 2036	5.62%	1,748	762
Unsecured Callable and Puttable Enhanced Securities SM , 4.10%, due 2038 ⁽⁶⁾		225	225
Tax-Exempt Financings: ⁽⁷⁾			
Variable rate, due 2008	3.69%	60	60
Variable rates, due 2015 to 2027	3.63%	137	137
4.95% to 7.65%, due 2007 to 2010	5.50%	232	237
2.3% to 7.55%, due 2014 to 2031	5.02%	263	263
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 7.375%, due 2042		412	412
Dominion Energy, Inc.:			
Secured Senior Note, 7.33%, due 2020 ⁽⁸⁾		213	222
Secured Bank Debt, Variable rates, due 2006 ⁽⁴⁾		—	347
Tax-Exempt Financing, 5.0%, due 2036		47	—
Dominion Capital, Inc.:			
Notes, 12.5%, due 2006 to 2008		4	6
Senior Note, Variable rate, due 2017 ⁽⁹⁾	5.63%	385	—
Dominion Resources Services, Inc., Secured Bank Debt, Variable rate, due 2006⁽⁴⁾			
		—	107
		17,313	17,070
Fair value hedge valuation ⁽¹⁰⁾		(6)	(52)
Amounts due within one year ⁽¹¹⁾	5.80%	(2,478)	(2,330)
Unamortized discount and premium, net		(38)	(35)
Total long-term debt		\$14,791	\$14,653

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2006.

(2) At the option of holders in August 2015, \$510 million of Dominion's 5.25% senior notes due 2033 are subject to redemption at 100% of the principal amount plus accrued interest.

(3) Convertible into a combination of cash and shares of our common stock at any time after March 31, 2004 when the closing price of our common stock equals \$88.32 per share or higher for at least 20 out of the last 30 consecutive trading days ending on the last trading day of the previous calendar quarter. 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. On December 15, 2006 less than \$100 thousand of the debt was redeemed due to holders exercising their put option.

(4) Represents debt associated with certain special purpose lessor entities consolidated in accordance with FIN 46R. The debt is nonrecourse to us and is secured by the entities' property, plant and equipment, which totaled \$337 million and \$943 million at December 31, 2006 and 2005, respectively.

(5) Substantially all of Virginia Power's property (\$12.4 billion at December 31, 2006) is subject to the lien of the mortgage, securing its mortgage bonds.

(6) On December 15, 2008, the securities are subject to redemption at par plus accrued interest, unless holders of related options exercise their rights to purchase and remarket the notes.

(7) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. The variable rate tax-exempt financings are supported by a \$3 billion five-year credit facility that terminates in February 2011. In February 2007, we exercised our call option and redeemed \$62 million of Virginia Power's tax-exempt financings with a weighted average rate of 7.52%, with proceeds raised through the issuance of commercial paper.

(8) Represents debt associated with our Kincaid power station. The debt is non-recourse to us and is secured by the facility's assets (\$526 million at December 31, 2006) and revenue.

(9) As discussed in Note 27, in June 2006, DCI began consolidating a CDO entity, in accordance with FIN 46R. The notes payable are nonrecourse to us.

(10) Represents the valuation of certain fair value hedges associated with our fixed-rate debt.

(11) Includes \$2 million of net unamortized premium, offset by a \$3 million fair value hedge valuation.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2006 were as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
(millions, except percentages)							
Secured Senior Notes	\$ 9	\$ 10	\$ 11	\$ 12	\$ 12	\$ 159	\$ 213
Secured First and Refunding Mortgage Bonds	215	—	—	—	—	—	215
Secured Bank Debt	370	—	—	—	—	—	370
Unsecured Senior Notes (including Medium-Term Notes)	1,863	1,413	313	1,444	965	7,230	13,228
Unsecured Callable and Puttable Enhanced Securities SM	—	—	—	—	—	225	225
Tax-Exempt Financings	20	157	115	5	5	437	739
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	1,134	1,134
Enhanced Junior Subordinated Notes	—	—	—	—	—	800	800
Other	2	2	—	—	—	385	389
Total	\$2,479	\$1,582	\$ 439	\$1,461	\$ 982	\$10,370	\$17,313
Weighted average coupon	5.80%	5.29%	5.38%	6.56%	6.60%	5.91%	

Our short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2006, there were no events of default under these covenants.

Convertible Securities

As described in Note 3, we entered into an exchange transaction with respect to \$220 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 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, when appropriate. 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 results in an increase in the average shares outstanding used in the calculation of our diluted EPS when the conversion price of \$73.60 is lower than the average market price of our common stock over the period, and results in no adjustment when the conversion price exceeds the average market price.

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 closing price of our common stock equals \$88.32 per share or higher for at least 20 out of the last 30 consecutive trading days ending on the last trading day of the previous calendar quarter;

- (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 Ratings Services, 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 2008, 2013 or 2018, or if we undergo certain fundamental changes.

Equity-Linked Securities

In 2002, we issued 6.6 million equity-linked debt securities, consisting of stock purchase contracts and senior notes. Total net proceeds were \$320 million. Long-term debt of \$330 million and an equity charge of \$36 million were recorded in our Consolidated Balance Sheet related to the issuance.

The stock purchase contracts obligated the holders to purchase shares of our common stock from us by May 2006. The purchase price was \$50 and the number of shares to be purchased was 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, were pledged as collateral to secure the purchase of common stock under the related stock purchase contracts. The holders were given the option to either 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 or continue to hold the senior notes and use other resources as consideration for the purchase of stock under the stock purchase contracts. In February 2006, we successfully remarketed the senior notes related to our equity-linked debt securities. The senior notes, which will mature in 2008, now carry an annual

interest rate of 5.687%; prior to the remarketing, the notes carried an annual interest rate of 5.75%.

Prior to conversion, we made quarterly interest payments on the senior notes and quarterly payments on the stock purchase contracts. Prior to conversion, we recorded the present value of the stock purchase contract payments as a liability, offset by a charge to common stock in shareholders' equity. The stock purchase contracts carried an annual interest rate of 3.00% prior to their settlement in May 2006, by issuance of 4.5 million shares of our common stock. Interest payments on the senior notes are recorded as interest expense and stock purchase contract payments were charged against the liability. Prior to conversion, accretion of the stock purchase contract liability was recorded as interest expense. In calculating diluted EPS, we applied the treasury stock method to the equity-linked debt securities. These securities did not have a significant effect on diluted EPS for 2006, 2005 or 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 trusts sold trust preferred securities representing preferred beneficial interests and 97% beneficial ownership in the assets held by the 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.

In October 2006, we redeemed all 12 million units of the \$300 million 8.4% Dominion Resources Capital Trust II debentures due January 30, 2041. The securities were redeemed at a price of \$25 per preferred security plus accrued and unpaid distributions. The following table provides summary information about the trust preferred securities and junior subordinated notes outstanding as of December 31, 2006:

Date Established	Capital Trusts	Units (thousands)	Rate	Trust Preferred Securities Amount	Common Securities Amount (millions)
December 1997	Dominion Resources Capital Trust I⁽¹⁾	250	7.83%	\$250	\$ 8
January 2001	Dominion Resources Capital Trust III⁽²⁾	250	8.4%	250	8
October 2001	Dominion CNG Capital Trust I⁽³⁾	8,000	7.8%	200	6
August 2002	Virginia Power Capital Trust II⁽⁴⁾	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) \$258 million—Dominion Resources, Inc. 8.4% Debentures due 1/15/2031.

(3) \$206 million—CNG 7.8% Debentures due 10/31/2041.

(4) \$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 notes. 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.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, we issued \$300 million of 2006 Series A Enhanced Junior Subordinated Notes due 2066 (June hybrids) and \$500 million of 2006 Series B Enhanced Junior Subordinated Notes due 2066 (September hybrids), respectively. The June hybrids will bear interest at 7.5% per year until June 30, 2016. Thereafter, they will bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.825%, reset quarterly. The September hybrids will bear interest at 6.3% per year until September 30, 2011. Thereafter, they will bear interest at the three-month LIBOR plus 2.3%, reset quarterly. We may defer interest payments on the hybrids on one or more occasions for up to 10 consecutive years. If the interest payments on the hybrids are deferred, we may not make distributions related to our capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, we may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the hybrids.

NOTE 19. SUBSIDIARY PREFERRED STOCK

Dominion is authorized to issue up to 20 million shares of preferred stock, however, none were issued and outstanding at December 31, 2006 or 2005.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, \$100 liquidation preference, and had 2.59 million preferred shares issued and outstanding at December 31, 2006 and 2005. 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, 2006:

Dividend	Issued and Outstanding Shares	Entitled Per Share Upon Liquidation
	(thousands)	
\$5.00	107	\$112.50
4.04	13	102.27
4.20	15	102.50
4.12	32	103.73
4.80	73	101.00
7.05	500	102.47 ⁽¹⁾
6.98	600	102.45 ⁽²⁾
Flex MMP 12/02, Series A	1,250	100.00 ⁽³⁾
Total	2,590	

(1) Through 7/31/2007; \$102.12 commencing 8/1/2007; amounts decline in steps thereafter to \$100.00 by 8/1/2013.

(2) Through 8/31/2007; \$102.10 commencing 9/1/2007; amounts decline in steps thereafter to \$100.00 by 9/1/2013.

(3) Dividend rate is 5.50% through 12/20/2007; after which, the rate will be determined according to periodic auctions for periods established by Virginia Power at the time of the auction process. This series is not callable prior to 12/20/2007.

NOTE 20. SHAREHOLDERS' EQUITY

Issuance of Common Stock

During 2006, we issued 6.6 million shares of common stock and received proceeds of \$479 million. Of this amount, 4.5 million shares and proceeds of \$330 million resulted from the settlement of stock purchase contracts associated with our 2002 issuance of equity-linked debt securities. The remainder of the shares issued and proceeds received were through Dominion Direct® (a dividend reinvestment and open enrollment direct stock purchase plan), employee savings plans and the exercise of employee stock options. From May 2006 until November 2006, we issued new common shares in consideration of proceeds received through these programs. In November 2006, we 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.

Pursuant to this authority, in November 2006 we repurchased 500 thousand shares of our common stock for approximately \$40 million. Additionally, in December 2006 we entered into a pre-paid accelerated share repurchase agreement (ASR) with a financial institution as the counterparty. Under the ASR, we will ultimately receive between 5.6 million and 6.5 million shares in exchange for the prepayment of \$500 million. At the time of execution of the ASR, the counterparty delivered to us 5 million shares. The final number of shares delivered to the Company will

be determined by a volume weighted average price of our common stock over the period commencing on December 12, 2006, and terminating on or before May 16, 2007. The actual termination date is at the option of the counterparty. The average price to be used to determine the final shares delivered to the Company is subject to a maximum and minimum price. Assuming normal termination, we will receive a minimum of 560 thousand additional shares. In no event will termination, normal or otherwise, result in the Company delivering shares or additional cash to the counterparty.

At December 31, 2006 the remaining purchase authorization is the lesser of 15.7 million shares or \$1.2 billion of our outstanding common stock.

Shares Reserved for Issuance

At December 31, 2006, we had a total of 33 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.

Accumulated Other Comprehensive Income (Loss)

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

At December 31,	2006	2005
(millions)		
Net unrealized losses on derivatives—hedging activities, net of tax	\$(422)	\$(2,777)
Net unrealized gains on investment securities, net of tax	282	165
Net unrecognized pension and other postretirement benefit costs, net of tax	(335)	—
Minimum pension liability adjustment, net of tax	—	(10)
Foreign currency translation adjustments	50	58
Total accumulated other comprehensive loss	\$(425)	\$(2,564)

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 Compensation, Governance and Nominating Committee of the Board of Directors or the Board of Directors itself, as provided under each individual plan. At December 31, 2006, approximately 14.8 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.

Our results for the years ended December 31, 2006, 2005 and 2004 include \$31 million, \$25 million and \$15 million, respectively, of compensation costs and \$11 million, \$10 million and \$6 million, respectively, of income tax benefits related to our stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in our Consolidated Statements of Income.

STOCK OPTIONS

The following table provides a summary of changes in amounts of stock options outstanding as of and for the years ended December 31, 2006, 2005 and 2004. No options were granted under any plan in 2006, 2005 and 2004.

	Shares	Weighted-average Exercise Price	Weighted-average Remaining Contractual Life	Aggregated Intrinsic Value ⁽¹⁾
	(thousands)		(years)	(millions)
Outstanding at December 31, 2003	18,544	\$56.97		
Exercisable at December 31, 2003	11,604	\$54.44		
Exercised	(4,632)	\$47.37		\$ 77
Forfeited/expired	(104)	\$60.89		
Outstanding at December 31, 2004	13,808	\$60.17		
Exercisable at December 31, 2004	10,768	\$60.01		
Exercised	(5,579)	\$59.79		\$ 77
Forfeited/expired	(15)	\$62.53		
Outstanding and exercisable at December 31, 2005	8,214	\$60.43		
Exercised	(947)	\$59.76		\$ 19
Forfeited/expired	(21)	\$60.79		
Outstanding and exercisable at December 31, 2006	7,246	\$60.51	3.2	\$167

(1) Intrinsic value represents the difference between the exercise price of the option and the market value of our stock.

We issue new shares to satisfy stock option exercises. We received cash proceeds from the exercise of stock options of approximately \$54 million, \$335 million and \$220 million in the years ended December 31, 2006, 2005 and 2004.

RESTRICTED STOCK

The fair value of our restricted stock awards is equal to the market price of our stock on the date of grant. These awards generally vest over a three-year service period and are settled by issuing new shares. The following table provides a summary of restricted stock activity for the years ended December 31, 2006, 2005 and 2004:

	Shares	Weighted-average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2003	639	\$58.80
Granted	582	63.29
Vested	(233)	63.26
Cancelled and forfeited	(28)	60.95
Nonvested at December 31, 2004	960	\$60.34
Granted	249	74.51
Vested	(30)	62.46
Cancelled and forfeited	(48)	63.27
Nonvested at December 31, 2005	1,131	\$63.27
Granted	338	70.43
Vested	(181)	60.75
Cancelled and forfeited	(42)	67.54
Nonvested at December 31, 2006	1,246	\$65.43

As of December 31, 2006, unrecognized compensation cost related to nonvested restricted stock awards totaled \$33 million and is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock awards that vested was \$14 million, \$2 million and \$15 million in 2006, 2005 and 2004, respectively. Employees may elect to have shares of restricted stock withheld upon vesting to satisfy tax withholding obligations. The number of shares withheld will vary for each employee depending on the vesting date fair value of Dominion stock and the applicable federal, state and local tax withholding rates.

GOAL-BASED STOCK

In April 2006, goal-based stock awards were granted to key non-officer employees. The issuance of shares under the awards is based on the achievement of multiple performance metrics during 2006 and 2007, including business unit goals, return on invested capital and total shareholder return relative to that of a peer group of companies. At December 31, 2006, the targeted number of shares to be issued is 97,150, but the actual number of shares issued will vary between zero and 200% of targeted shares, depending on the level of performance metrics achieved. The fair value of goal-based stock is equal to the market price of our stock on the date of grant. Awards will vest in April 2009 and be settled by issuing new shares. The following table provides a summary of goal-based stock activity:

	Targeted Number of Shares	Weighted- Average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2005	—	\$ —
Granted	100.0	69.53
Vested	—	—
Cancelled and forfeited	(2.85)	69.53
Nonvested at December 31, 2006	97.15	\$69.53

As of December 31, 2006, unrecognized compensation cost related to nonvested goal-based stock awards totaled \$5 million and is expected to be recognized over a weighted-average period of 1.7 years.

CASH-BASED PERFORMANCE GRANT

In April 2006, a cash-based performance grant was made to officers. Payout of the performance grant will occur by March 15, 2008 and is based on the achievement of two performance metrics during 2006 and 2007: return on invested capital and total shareholder return relative to that of a peer group of companies. At December 31, 2006, the targeted amount of the grant is \$14 million, but actual payout will vary between zero and 200% of the targeted amount, depending on the level of performance metrics achieved. At December 31, 2006, a liability of \$6 million has been accrued for this award.

NOTE 21. DIVIDEND RESTRICTIONS

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 to be detrimental to the public interest. At December 31, 2006, 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, 2006.

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 and interest payments on enhanced junior subordinated notes.

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 the employee's 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.

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 use December 31 as the measurement date for 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.

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:

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	2006	2005	2006	2005
(millions)				
Change in benefit obligation:				
Benefit obligation at beginning of year	\$3,834	\$3,410	\$1,622	\$1,381
Acquisitions	—	15	—	44
Service cost	124	110	72	64
Interest cost	210	201	81	83
Benefits paid	(175)	(142)	(72)	(67)
Actuarial (gain) loss during the year ⁽¹⁾	(329)	231	(395)	143
Plan amendments	2	9	(11)	(26)
Benefit obligation at end of year	\$3,666	\$3,834	\$1,297	\$1,622
Change in plan assets:				
Fair value of plan assets at beginning of year	\$4,360	\$4,049	\$ 794	\$ 697
Acquisitions	—	15	—	10
Actual return on plan assets	589	433	85	51
Contributions	19	5	68	72
Benefits paid from plan assets	(175)	(142)	(38)	(36)
Fair value of plan assets at end of year	\$4,793	\$4,360	\$ 909	\$ 794
Funded status	\$1,127	\$ 526	\$ (388)	\$ (828)
Unrecognized net actuarial loss	—	1,288	—	491
Unrecognized prior service cost (credit)	—	34	—	(32)
Unrecognized net transition obligation	—	—	—	23
Net asset (liability) recognized	\$1,127	\$1,848	\$ (388)	\$ (346)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	\$1,240	\$1,915	\$ 6	\$ —
Other current liabilities	(2)	—	—	—
Noncurrent pension and other postretirement benefit liabilities	(111)	(115)	(394)	(346)
Intangible asset	—	31	—	—
Accumulated other comprehensive loss to offset additional minimum liability	—	17	—	—
Net amount recognized	\$1,127	\$1,848	\$ (388)	\$ (346)

(1) The 2006 actuarial gain for pension benefits primarily resulted from increases in the discount rate and the expected retirement age. The 2006 actuarial gain for other postretirement benefits primarily resulted from an increase in the discount rate and a decrease in expected future benefit claims.

The following table summarizes the overfunded and underfunded status of our benefit plans recognized in our Consolidated Balance Sheet at December 31, 2006:

	Pension Benefits	Other Postretirement Benefits
Funded status of overfunded plans	\$1,240	\$ 6
Funded status of underfunded plans	(113)	(394)
Funded status	\$1,127	\$(388)

The accumulated benefit obligation for all of our defined benefit pension plans was \$3.2 billion and \$3.3 billion at December 31, 2006 and 2005, 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 \$110 million and \$134 million at December 31, 2006 and 2005, respectively. The total accumulated benefit obligation for these plans was \$65 million and \$118 million at December 31, 2006 and 2005, 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 at December 31, 2005. SFAS No. 158 eliminates the requirement to recognize an additional minimum liability; however, had we not been required to adopt SFAS No. 158, we would not have recognized an additional minimum liability at December 31, 2006.

We do not expect any pension or postretirement benefit plan assets to be returned to the Company during 2007.

The following table reflects amounts recognized in AOCI in our Consolidated Balance Sheet at December 31, 2006 that have not yet been recognized as components of net periodic benefit cost:

	Pension Benefits		Other Postretirement Benefits	
	AOCI After Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After Tax	AOCI After Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After Tax
(millions)				
Unrecognized net transition obligation	\$ —	\$—	\$ 6	\$(2)
Unrecognized net actuarial loss	(334)	20	18	(2)
Unrecognized prior service cost	(13)	2	(12)	3
Total	\$(347)	\$22	\$ 12	\$(1)

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

	Pension Benefits	Other Postretirement Benefits
(millions)		
2007	\$ 155	\$ 74
2008	171	80
2009	180	85
2010	204	91
2011	196	95
2012-2016	1,273	546

The above benefit payments for other postretirement benefit plans are expected to be offset by Medicare Part D subsidies of approximately \$4 million annually for the years 2007 through 2011 and approximately \$27 million during the period 2012 through 2016.

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 funds is 34% U.S. equity securities, 12% non-U.S. equity securities, 22% debt securities, 7% real estate and 25% other, such as 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:

Year Ended December 31,	Pension Plans				Other Postretirement Plans			
	2006		2005		2006		2005	
	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total	Fair Value	% of Total
(millions)								
Equity securities:								
U.S.	\$1,491	31	\$1,750	40	\$369	41	\$330	42
International	751	16	607	14	106	11	90	11
Debt securities	1,356	28	990	23	335	37	289	36
Real estate	376	8	340	8	25	3	21	3
Other	819	17	673	15	74	8	64	8
Total	\$4,793	100	\$4,360	100	\$909	100	\$794	100

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

Year Ended December 31,	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
(millions)						
Service cost	\$ 124	\$ 110	\$ 97	\$ 72	\$ 64	\$ 63
Interest cost	210	201	190	81	83	83
Expected return on plan assets	(357)	(341)	(336)	(62)	(51)	(44)
Amortization of prior service cost (credit)	4	3	2	(4)	(1)	—
Amortization of transition obligation	—	—	—	3	3	7
Amortization of net loss	89	77	56	24	19	21
Settlements and curtailments ⁽¹⁾	12	—	—	—	—	—
Net periodic benefit cost	\$ 82	\$ 50	\$ 9	\$114	\$117	\$130

(1) Relates to the pending sale of Peoples and Hope and the impact of distributions to retired executives.

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

Year Ended December 31,	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
Discount rate	5.60%	6.00%	6.25%	5.50%	6.00%	6.25%
Expected return on plan assets	8.75%	8.75%	8.75%	8.00%	8.00%	7.79%
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) The medical cost trend rate for 2006 is assumed to gradually decrease to 5.00% by 2010 and continues at that rate for 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:

At December 31,	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	6.20%	5.60%	6.10%	5.50%
Rate of increase for compensation	4.79%	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.

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	One percentage point decrease
(millions)		
Effect on total service and interest cost components for 2006	\$ 30	\$ (24)
Effect on postretirement benefit obligation at December 31, 2006	160	(120)

In addition, we sponsor defined contribution thrift-type savings plans. During 2006, 2005 and 2004, we recognized \$36 million, \$33 million and \$29 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 (VEBAs). Our remaining subsidiaries do not prefund postretirement benefit costs but instead pay claims as presented. We expect to contribute \$31 million to the Dominion VEBAs in 2007.

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, 2006, we had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

	2007	2008	2009	2010	2011	Thereafter	Total
(millions)							
Purchased electric capacity ⁽¹⁾	\$414	\$383	\$362	\$349	\$348	\$2,207	\$4,063
Production handling for gas and oil production operations ⁽²⁾	54	43	26	15	11	5	154

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2006, the present value of our total commitment for capacity payments is \$2.6 billion. Capacity payments totaled \$437 million, \$472 million and \$570 million, and energy payments totaled \$291 million, \$378 million and \$293 million for 2006, 2005 and 2004, respectively.

(2) Payments under this contract, which ends in 2012, totaled \$56 million, \$52 million and \$22 million in 2006, 2005 and 2004, respectively.

Lease Commitments

We lease various facilities, onshore and offshore drilling rigs, vehicles and equipment primarily under operating leases. The lease agreements expire on various dates and certain of the leases are renewable and contain options to purchase the leased property. Payments under certain leases are escalated based on an index such as the Consumer Price Index (CPI). Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2006 are as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
(millions)	\$209	\$182	\$163	\$131	\$119	\$294	\$1,098

Rental expense totaled \$178 million, \$160 million and \$123 million for 2006, 2005 and 2004, respectively, the majority of which is reflected in other operations and maintenance expense. Lease payments associated with our onshore and offshore drilling commitments are capitalized under the full cost method of accounting for gas and oil E&P activities.

We have an agreement 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.

Other Commitment

In December 2006, we acquired a 50% interest in a joint venture with Shell WindEnergy Inc. (Shell) to develop a wind-turbine facility in Grant County, West Virginia. We have committed to contribute approximately \$168 million of cash at various dates through January 2008 which includes our initial investment and funding for the development of the project that will produce approximately 164 Mw of electricity.

Environmental Matters

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

To the extent environmental costs are incurred in connection with operations regulated by the Virginia Commission during the period ending December 31, 2010, in excess of the level currently included in Virginia jurisdictional rates, our results of operations will decrease. After that date, we may seek recovery through rates

of only those environmental costs related to our transmission and distribution operations. However, the foregoing risks are subject to change upon the adoption, if any, of the proposed 2007 Virginia Restructuring Act Amendments as discussed later under *2007 Virginia Restructuring Act Amendments*.

SUPERFUND SITES

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

In 1987, we and a number of other entities were identified by the EPA as PRPs at two Superfund sites located in Kentucky and Pennsylvania. In 2003, the EPA issued its Certificate of Completion of remediation for the Kentucky site. Future costs for the Kentucky site will be limited to minor operations and maintenance expenditures. Regarding the Pennsylvania site, in March 2006, a federal district court approved three consent decrees between the U.S. and the PRPs, under which we and certain other PRPs, all of which are utilities, will perform the site remediation. The remediation costs are expected to be in the range of \$11 million to \$18 million, the majority of which are to be paid by the non-utility site owners. After evaluating the impact of these actions, we have reduced our current reserve from \$2 million to less than \$1 million to meet our potential obligations at these two sites. We generally seek to recover our costs associated with environmental remediation from third-party insurers. At December 31, 2006, no pending or possible insurance claims were recognized as an asset or offset against obligations.

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. In April 2006, we entered into a settlement agreement with the plaintiffs resolving all of their claims against us. In May 2006, the plaintiffs non-suited Dominion with prejudice, resulting in the dismissal of the case. We remain subject however, to a cross-claim and an indemnity claim with certain of the other defendants that were not a party to our settlement with the plaintiffs. Neither claim is material and we do not expect the resolution of these remaining claims or the settlement to have a material adverse effect on the results of operations or financial condition.

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. One of the former sites is conducting a state approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. At another site we have been accepted into a state-based voluntary remediation program. It is not known to what degree the other former 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 2006 NRC minimum financial assurance amount, aggregated for our nuclear units, was \$2.3 billion and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC.

NUCLEAR INSURANCE

The Price-Anderson Act provides the public up to \$10.8 billion of 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. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., we could be assessed up to \$100.6 million for each of our 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 billion 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 \$97 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 \$34 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 to us 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 lawsuits in the U.S. Court of Federal Claims against the DOE in connection with its failure to commence accepting spent nuclear fuel. Trial is scheduled for March 2008. We will continue to manage our spent fuel until it is accepted by the DOE.

Insurance for E&P Operations

In the past, we have maintained business interruption insurance, property damage and other insurance for our E&P operations. However, the increased level of hurricane activity in the Gulf of Mexico led our insurers to terminate certain coverages for our E&P operations; specifically, our Operator's Extra Expense (OEE), offshore property damage and offshore business interruption coverage was terminated. All onshore property coverage (with the exception of OEE) and liability coverage commensurate with past coverage remained in place for our E&P operations under our current policy. Recently our OEE coverage for both onshore and offshore E&P operations was reinstated under a new policy. However, efforts to replace the terminated insurance for our E&P operations for offshore property damage and offshore business interruption with similar traditional insurance on commercially reasonable terms were unsuccessful. In June 2006, we entered into a six-month weather derivative contract with an SPE. This arrangement provided limited alternative risk mitigation; however, it offered substantially less protection than our previous E&P insurance policies. This lack of insurance could adversely affect our results of operations.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2006, we had issued \$32 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 E&P 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 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 believe is improb-

able. We have not recognized any significant liabilities related to any of these guarantee arrangements.

In 2006, we, along with three other gas and oil exploration companies, executed agreements with a third party to design, construct, install and own the Thunder Hawk facility, a semi-submersible production facility to be located in the deepwater Gulf of Mexico. We anticipate that mechanical completion of the Thunder Hawk facility will occur in 2009 and that the processing of our production will start by 2010. Due to current offshore insurance market conditions, it is anticipated that the Thunder Hawk facility will only be partially insured against a catastrophic full or partial loss. We, along with the three other participating producers, will be required to continue to make demand payments in the event of a catastrophic loss if insurance payments are not sufficient to pay the lessor's outstanding debt incurred for the Thunder Hawk facility. The agreements require that we pay a demand charge of approximately \$63 million over five years starting on the day after the mechanical completion of the Thunder Hawk facility. Our obligation will terminate upon the earlier event of full payment of the lessor's debt incurred for the Thunder Hawk facility or the full payment of our demand charge obligation. We believe that it is unlikely that we would be required to perform under this guarantee and have not recognized any significant liabilities for this arrangement. The agreements also require the payment of production processing fees including a minimum processing fee if yearly production processing fees are below specified amounts. Our maximum obligation for the minimum processing fee would be approximately \$3 million per year. Our obligation for the payment of these processing fees will terminate upon the cessation of our production.

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, 2006. 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, 2006, we had issued the following subsidiary guarantees:

	Stated Limit	Value ⁽¹⁾
(millions)		
Subsidiary debt ⁽²⁾	\$ 624	\$ 624
Commodity transactions ⁽³⁾	3,751	744
Lease obligation for power generation facility ⁽⁴⁾	898	898
Nuclear obligations ⁽⁵⁾	375	303
Offshore drilling commitments ⁽⁶⁾	—	493
Other	727	510
Total	\$6,375	\$3,572

(1) Represents the estimated portion of the guarantee's stated limit that is utilized as of December 31, 2006 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 debt of certain DEI and CNG subsidiaries. In the event of default by the subsidiaries, we would be obligated to repay such amounts.

- (3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power, 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 certain DEI subsidiaries' potential retrospective premiums that could be assessed if there is a nuclear incident under our nuclear insurance programs and guarantees for Virginia Power's commitment to buy nuclear fuel. In addition to the guarantees listed above, we have also agreed to provide up to \$150 million and \$60 million to two DEI subsidiaries, to pay operating expenses of Millstone and Kewaunee power stations, respectively, in the event of a prolonged outage as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of nuclear power stations.
- (6) Performance and payment guarantees related to an offshore daywork drilling contract, rig share agreements and related services for certain subsidiaries of CNG. There are no stated limits for these guarantees.

Additionally, as of December 31, 2006, we had purchased \$127 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of \$844 million 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, 2006, we believe future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on our results of operations, cash flows or financial position.

We have entered into other types of contracts that require indemnifications, such as purchase and sale agreements and financing agreements. These agreements may include, but are not limited to, indemnifications around certain title, tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price and is typically limited in duration depending on the nature of the indemnified matter. Since January 1, 2004, we have entered into sale agreements with maximum exposure related to the collective purchase prices of approximately \$2.0 billion. We believe that it is improbable that we would be required to perform under these indemnifications and have not recognized any significant liabilities related to these arrangements.

Stranded Costs

Stranded costs are generation-related costs incurred or commitments made by utilities under cost-based regulation that may not be reasonably expected to be recovered in a competitive market. At December 31, 2006, our exposure to potential stranded costs included long-term power purchase contracts that could ultimately be determined to be above market prices; generating plants that could possibly become uneconomical in a deregulated environment; and unfunded obligations for nuclear plant decommissioning and postretirement benefits. We believe capped electric retail rates will provide an opportunity to recover our potential stranded costs, depending on market prices of electricity and other factors. Recovery of our potential stranded costs remains subject to numerous risks even in the capped-rate environment. These risks include, among others, exposure to long-term power purchase commitment losses, future environmental compliance requirements, changes in certain tax laws, nuclear decommissioning costs, increased fuel costs, inflation, increased capital costs and recovery of certain other items.

The Virginia Electric Utility Restructuring Act was enacted in 1999 (1999 Virginia Restructuring Act) and established a plan to restructure the electric utility industry in Virginia. Under the 1999 Virginia Restructuring Act, the generation portion of our Virginia jurisdictional operations is no longer subject to cost-based regulation. The legislation's deregulation of generation was an event that required us to discontinue the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, to the Virginia jurisdictional portion of our generation operations in 1999. The 1999 Virginia Restructuring Act also permits wires charges to be collected by utilities until July 1, 2007. Our wires charges are set at zero in 2007 for all rate classes, and as such, Virginia customers will not pay a fee if they switch from us to a different competitive service provider.

Virginia Fuel Expenses

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

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

Fuel prices have increased considerably since our Virginia fuel factor provisions were frozen in 2004, which has resulted in our fuel expenses being significantly in excess of our rate recovery. We expect that fuel expenses will continue to exceed rate recovery until our fuel factor is adjusted in July 2007.

While the 2006 amendments do not allow us to collect any unrecovered fuel expenses that were incurred prior to July 1,

2007, once our fuel factor is adjusted, the risk of under-recovery of prudently incurred fuel costs until July 1, 2010 is greatly diminished.

2007 Virginia Restructuring Act Amendments

In February 2007, both houses of the Virginia General Assembly passed identical bills that would significantly change electricity restructuring in Virginia. The bills would end capped rates two years early, on December 31, 2008. After capped rates end, retail choice would be eliminated for all but individual retail customers with a demand of more than 5 Mw and a limited number of non-residential retail customers whose aggregated load would exceed 5 Mw. Also, after the end of capped rates, the Virginia Commission would set the base rates of investor-owned electric utilities under a modified cost-of-service model. Among other features, the currently proposed model would provide for the Virginia Commission to:

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

- Authorize an enhanced ROE as a financial incentive for construction of major baseload generation projects and for renewable energy portfolio standard programs.

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

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

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

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,	2006		2005	
	Carrying Amount	Estimated Fair Value ⁽¹⁾	Carrying Amount	Estimated Fair Value ⁽¹⁾
(millions)				
Long-term debt ⁽²⁾	\$15,320	\$15,576	\$15,567	\$15,928
Junior subordinated notes payable to:				
Affiliates	1,151	1,209	1,416	1,537
Other	798	828	—	—

(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.

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our December 31, 2006 provision for credit losses, that it is unlikely that a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

As a diversified energy company, we transact with major companies in the energy industry and with commercial and residential energy consumers. Except for our E&P business activities, these transactions principally occur in the Northeast, Mid-Atlantic and Midwest regions of the U.S. 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 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 our energy marketing and risk management 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. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2006, our gross credit exposure totaled \$1.36 billion. After the application of collateral, our credit exposure is reduced to \$1.33 billion. Of this amount, investment grade counterparties represented 83% and no single counterparty exceeded 9%.

NOTE 26. EQUITY AND COST-METHOD INVESTMENTS

Equity-Method Investments

At December 31, 2006 and 2005, our equity method investments totaled \$289 million and \$331 million, respectively, and equity earnings on these investments totaled \$37 million in 2006, \$43 million in 2005 and \$34 million in 2004. We received dividend income from these investments of \$21 million, \$28 million and \$37 million in 2006, 2005 and 2004, respectively. Also during 2006, we sold two of our equity method investments, resulting in a net loss of \$3 million. Our equity method investments are reported in our Consolidated Balance Sheets in other investments. Equity earnings on these investments are reported in our Consolidated Statements of Income in other income.

Cost-Method Investments

At December 31, 2006 and 2005, the carrying value of our cost-method investments totaled \$37 million and \$4 million, respectively. In 2006 and 2005, we reviewed all of our cost-method investments for evidence of adverse changes in fair value; however, we did not estimate the fair value of our cost-method investments unless we identified events or changes in circumstances that had a significant adverse effect on the fair value of the investments.

International Investments

CNG International (CNGI) was engaged in energy-related activities outside of the U.S., primarily through equity investments in Australia and Argentina. After completing the CNG acquisition in 2000, we committed to a plan to dispose of the entire CNGI operation consistent with our strategy to focus on the eastern region of the U.S.

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 our investment in an Australian pipeline business. At December 31, 2005, our remaining CNGI investment was accounted for at its fair value of \$4 million. During 2006, we wrote off our remaining investment.

Investment in Wind-Power Facility

In December 2006, we acquired a 50% interest in a joint venture with Shell to develop a wind-turbine facility in Grant County, West Virginia, which will produce approximately 164 Mw of electricity and is expected to be in operation in the fourth quarter of 2007.

NOTE 27. DOMINION CAPITAL, INC.

Our Consolidated Balance Sheets reflect the following DCI assets:

At December 31,	2006	2005
(millions)		
Current assets ⁽¹⁾	\$229	\$108
Loans receivable, net	399	31
Available-for-sale securities	39	286
Other investments	81	58
Property, plant and equipment, net	10	10
Deferred charges and other assets	83	87
Total	\$841	\$580

(1) Includes \$36 million of loans receivable, net in 2006.

Securitizations of Financial Assets

At December 31, 2006 and 2005, DCI held \$39 million and \$286 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 CDO and collateralized mortgage obligation (CMO) transactions.

In connection with ongoing efforts to divest our remaining financial services investments, we executed certain agreements in 2003 that resulted in the sale of certain financial assets in exchange for an investment in the subordinated notes of a third-party CDO entity. This investment consisted of \$100 million of Class B-1 Notes, 7.5% current pay interest and \$148 million of Class B-2 Notes, 3% paid-in-kind (PIK) interest. The equity interest in the new CDO entity, a voting interest entity, were held

by an entity that is not affiliated with us. The CDO entity's primary focus is the purchase and origination of middle market senior secured first and second lien commercial and industrial loans in both the primary and secondary loan markets.

Prior to June 2006, our intent was to rate and market the B-1 Notes and hold the B-2 Notes to maturity. DCI also had a commitment to fund up to \$15 million of liquidity to the CDO entity, but this commitment has expired. The equity interests in the CDO entity are held by another entity that is not affiliated with us.

We have decided to pursue the sale of the B-2 Notes. In June 2006, we recorded an \$85 million charge in other operations and maintenance expense reflecting an other-than-temporary decline in the fair value of the B-2 Notes. An impairment was required because of a further increase in interest rates, an increase in our credit risk associated with the equity reduction discussed below and because we no longer expect the fair value of the B-2 Notes to recover prior to a sale.

DCI's investments in the CDO entity were previously included in available-for-sale securities in our Consolidated Balance Sheet. In June 2006, the equity investor reduced its equity at risk in the CDO entity, which required a redetermination of whether the CDO entity is a VIE under FIN 46R. We concluded that the CDO entity is a VIE and that DCI is the primary beneficiary of the CDO entity, which we have consolidated in accordance with FIN 46R. Due to its consolidation, we now reflect the assets and liabilities of the CDO entity in our Consolidated Balance Sheet. At December 31, 2006, the CDO entity had \$385 million of notes payable that mature in January 2017 and are nonrecourse to us. The CDO entity held the following assets that serve as collateral for its obligations at December 31, 2006:

	Amount
(millions)	
Other current assets ⁽¹⁾	\$183
Loans receivable, net	367
Other investments	36
Total assets	\$586

(1) Includes \$36 million of loans receivable, net in 2006.

There were no mortgage securitizations in 2005 or 2006. Activity for the subordinated notes related to the CDO entity, retained interests from securitizations of CMOs and CDO retained interests is summarized as follows:

	CMO	Retained Interests —CDO ⁽¹⁾
(millions)		
Balance at January 1, 2005	\$ 67	\$ 268
Interest income	—	11
Proceeds from the sale of CDOs	—	(16)
Other cash received	(1)	(8)
Fair value adjustment	(28)	—
Balance at December 31, 2005	\$ 38	\$ 255
Interest income	—	12
Consolidation of CDO	—	(171)
Cash received	(1)	(11)
Fair value adjustment	2	(85)
Balance at December 31, 2006	\$ 39	\$ —

(1) Includes interest receivable.

Loans Related to the CDO Entity

Presented below are the significant accounting policies associated with loans receivable reflected on our balance sheet due to consolidation of the CDO entity:

LOANS RECEIVABLE

Loans receivable are recorded at cost and valued at the lower of cost or realizable value. A loan is considered non-performing if it meets the definition of either a (i) Defaulted Security, or (ii) PIK Security, where interest has been deferred or paid-in-kind for three months (or 6 months in the case of a security that is only required to pay interest on a quarterly basis).

- In general, a Defaulted Security is: 1) a loan where a default as to the payment of principal and/or interest has occurred and is continuing, 2) a loan that has a Standard & Poor's Rating of "D" or "SD" or has a Moody's Rating of "Ca" or lower; and, 3) a loan that in the reasonable business judgment of the CDO entity's collateral manager, is a Defaulted Security.
- In general, a PIK Security is a loan with respect to which the obligor has the right to defer or capitalize all or a portion of the interest due on such loan as principal, unless such asset is required on each payment date to pay in cash a spread of at least the LIBOR plus 2.50%.

The CDO entity's loans receivable balance at December 31, 2006 is summarized as follows:

	Performing	Non-performing	Total
(millions)			
Loans receivable ⁽¹⁾	\$394	\$16	\$410
Allowance for loan losses	(2)	(5)	(7)
Loans receivable, net	\$392	\$11	\$403

(1) Current portion: Performing—\$28 million; Non-performing—\$8 million

The notional value of the non-performing portfolio at December 31, 2006 was \$148 million. During 2006, the CDO entity recorded a \$7 million provision for loan losses and recorded direct write-offs, net of recoveries amounting to \$20 million. The interest income earned in 2006 from cash collections on non-performing loans was \$1 million. There were no loans held for sale at December 31, 2006.

ALLOWANCE FOR LOAN LOSSES

The allowance for loan losses is a significant estimate that represents the CDO entity's estimate of probable losses inherent in the loan portfolio and equity investments as determined by the CDO entity's collateral manager.

In calculating the allowance for loan losses, the CDO entity's collateral manager applies a systematic and consistent approach that considers among other factors: historical payment experience, past-due status, current financial information, ability of the debtors to generate cash flows and realizable value of collateral on a loan by loan basis. Each material non-performing loan and material equity investment is reviewed on a quarterly basis. A range of probable losses is estimated for each loan after which a probable loss is determined.

A loan is written off when it is considered fully uncollectible and of such little value that its continuance as an asset is not warranted. A loan or equity investment is also written off if the bor-

rower has ceased operations, the majority of the borrower's assets have been liquidated or sold, or the remaining collections of the loans are speculative and expected to be minimal or highly contingent.

LOAN ORIGATION FEES AND COSTS

Loan origination fees and costs are deferred and recorded as part of loans receivable and then amortized over the life of the loan as an adjustment to the yield in interest income.

DEFERRED FINANCING CLOSING

Costs incurred to refinance debt are deferred and amortized over the life of the notes. All costs associated with any notes that are paid in full are expensed at the date of the payoff.

Key Economic Assumptions and Sensitivity Analyses

The loans receivable held by the CDO entity are subject to credit loss and interest rate risk. Adverse changes of up to 20% in credit losses and interest rates are estimated in each case to have less than an \$80 million pre-tax impact on future results of operations.

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 \$2 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,	2006	2005	2004
(millions)			
Retained interests from CMO securitizations ⁽¹⁾	\$—	\$25	\$46
Retained interests from CDO securitizations ⁽¹⁾	85	—	13
Venture capital and other equity investments ⁽²⁾	6	10	26
Total	\$91	\$35	\$85

(1) Reflects the 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 and CDO securitizations in 2006, 2005 and 2004. We updated our credit loss and prepayment assumptions to reflect our recent experience.

(2) Other impairments were recorded primarily due to asset dispositions.

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. Beginning in 2005, the financial impact of the Clearinghouse's optimization of company assets is 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 commodity risk management 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 2004 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 were redesignated as 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 redesignated contracts were previously presented in operating revenue on a net basis. Upon redesignation as non-trading, all unrealized changes in fair value and settlements related to those derivative contracts that are financially settled are reported in other operations and maintenance expense. The statement of income related amounts for those reclassified derivative sales contracts that are physically settled are presented in operating revenue, while the statement of income related amounts for physically-settled purchase contracts are reported in operating expenses.

We are organized primarily on the basis of products and services sold in the U.S. We manage our operations through the following segments:

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

Dominion Energy includes our tariff-based electric transmission, natural gas transmission pipeline and underground natural gas storage businesses and the Cove Point LNG facility. It also includes gathering and extraction activities, certain Appalachian natural gas production and producer services, which consist of aggregation of gas supply, market-based services related to gas transportation and storage, associated gas trading and the 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 price risk management activities associated with our generation assets.

Dominion E&P includes our gas and oil exploration, development and production operations. These 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, West Texas, Mid-Continent, the Rockies and Appalachia, as well as the Western Canadian Sedimentary Basin.

Corporate includes our corporate, service company and other functions (including unallocated debt), corporate-wide commodity risk management, the remaining assets of DCI, the net impact of our discontinued telecommunications operations that were sold in May 2004, and the net impact of the discontinued operations of the Peaker facilities. 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 2006, we reported net expenses of \$149 million in the Corporate segment attributable to our operating segments.

The net expenses in 2006 primarily related to the impact of the following:

- A \$166 million (\$104 million after-tax) charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, attributable to Dominion Delivery;
- A \$21 million tax benefit from the partial reduction of previously recorded valuation allowances on certain federal and state tax loss carryforwards (attributable to Dominion Generation), since these carryforwards are expected to be utilized to offset capital gain income that will be generated from the sale of Peoples and Hope;
- A \$27 million (\$17 million after-tax) charge resulting from the cancellation of a pipeline project, attributable to the Energy segment; and
- A \$26 million impairment (\$15 million after-tax) charge in the fourth quarter resulting from a change in our method of assessing other-than-temporary declines in the fair value of securities held as investments in our nuclear decommissioning trusts.

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 2005 hurricanes 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. At December 31, 2005, we had not recognized any deferred tax benefits related to the charge, since realization of tax benefits was not anticipated at that 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.

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

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
2006							
Total revenue from external customers	\$4,226	\$1,369	\$6,971	\$3,026	\$ (45)	\$ 935	\$16,482
Intersegment revenue	17	1,202	137	216	717	(2,289)	—
Total operating revenue	4,243	2,571	7,108	3,242	672	(1,354)	16,482
Depreciation, depletion and amortization	323	127	311	813	35	(3)	1,606
Equity in earnings of equity method investees	1	12	18	2	4	—	37
Interest income	19	20	65	15	199	(203)	115
Interest and related charges	211	70	259	184	509	(203)	1,030
Income tax expense (benefit)	257	248	351	404	(340)	—	920
Loss from discontinued operations, net of tax	—	—	—	—	(183)	—	(183)
Net income (loss)	438	360	537	680	(635)	—	1,380
Investment in equity method investees	5	99	119	6	60	—	289
Capital expenditures	518	420	1,018	2,079	17	—	4,052
Total assets (billions)	10.2	6.3	16.1	13.2	15.6	(12.1)	49.3
2005							
Total revenue from external customers	\$4,299	\$1,675	\$8,035	\$2,644	\$ 29	\$ 1,289	\$17,971
Intersegment revenue	38	1,405	203	246	588	(2,480)	—
Total operating revenue	4,337	3,080	8,238	2,890	617	(1,191)	17,971
Depreciation, depletion and amortization	329	121	351	563	35	(2)	1,397
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	264	140	538	(251)	966
Income tax expense (benefit)	253	212	224	324	(425)	—	588
Loss from discontinued operations, net of tax	—	—	—	—	(8)	—	(8)
Cumulative effect of change in accounting principle, net of tax	—	—	—	—	(6)	—	(6)
Net income (loss)	448	319	416	565	(715)	—	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	\$3,759	\$2,047	\$4,896	\$2,291	\$ 69	\$ 867	\$13,929
Intersegment revenue	75	384	793	157	509	(1,918)	—
Total operating revenue	3,834	2,431	5,689	2,448	578	(1,051)	13,929
Depreciation, depletion and amortization	316	116	266	558	35	(2)	1,289
Equity in earnings (losses) 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	241	94	622	(244)	926
Income tax expense (benefit)	256	119	326	314	(310)	—	705
Loss from discontinued operations, net of tax	—	—	—	—	(24)	—	(24)
Net income (loss)	466	190	533	595	(535)	—	1,249

As of December 31, 2006 and 2005, approximately 2% of our total long-lived assets were associated with international operations. For the years ended December 31, 2006, 2005 and 2004, approximately 1%, 1% and 2%, respectively, of operating revenues were associated with international operations.

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 depletion follow:

At December 31,	2006	2005
(millions)		
Capitalized costs:		
Proved properties	\$11,747	\$ 9,929
Unproved properties	1,980	1,775
	13,727	11,704
Accumulated depletion:		
Proved properties	3,506	2,513
Unproved properties	144	109
	3,650	2,622
Net capitalized costs	\$10,077	\$ 9,082

Total Costs Incurred

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

Year Ended December 31,	2006			2005			2004		
	Total	United States	Canada	Total	United States	Canada	Total	United States	Canada
(millions)									
Property acquisition costs:									
Proved properties	\$ 87	\$ 87	\$ —	\$ 118	\$ 118	\$—	\$ 20	\$ 20	\$ —
Unproved properties	171	165	6	151	137	14	116	102	14
	258	252	6	269	255	14	136	122	14
Exploration costs	399	383	16	235	230	5	213	199	14
Development costs ⁽¹⁾	1,451	1,365	86	1,207	1,128	79	915	841	74
Total	\$2,108	\$2,000	\$108	\$1,711	\$1,613	\$98	\$1,264	\$1,162	\$102

(1) Development costs incurred for proved undeveloped reserves were \$302 million, \$284 million and \$172 million for 2006, 2005 and 2004, 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,	2006			2005			2004		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
(millions)									
Revenue (net of royalties) from:									
Sales to nonaffiliated companies	\$1,883	\$1,749	\$134	\$1,499	\$1,369	\$130	\$1,526	\$1,297	\$229
Transfers to other operations	253	253	—	268	268	—	195	195	—
Total	2,136	2,002	134	1,767	1,637	130	1,721	1,492	229
Less:									
Production (lifting) costs	552	510	42	443	406	37	394	309	85
Depreciation, depletion and amortization	801	750	51	564	525	39	560	497	63
Income tax expense	285	271	14	283	264	19	295	266	29
Results of operations	\$ 498	\$ 471	\$ 27	\$ 477	\$ 442	\$ 35	\$ 472	\$ 420	\$ 52

Company-Owned Reserves

Estimated net quantities of proved gas and oil (including condensate) reserves in the U.S. and Canada at December 31, 2006, 2005 and 2004, and changes in the reserves during those years, are shown in the two schedules that follow:

	2006			2005			2004		
	Total	United States	Canada	Total	United States	Canada	Total	United States	Canada
(billion cubic feet)									
Proved developed and undeveloped reserves—Gas									
At January 1	4,962	4,856	106	4,910	4,814	96	5,161	4,718	443
Changes in reserves:									
Extensions, discoveries and other additions	431	393	38	299	276	23	387	342	45
Revisions of previous estimates ⁽¹⁾	109	58	51	73	71	2	2	141	(139)
Production	(318)	(302)	(16)	(290)	(275)	(15)	(348)	(312)	(36)
Purchases of gas in place	48	48	—	55	55	—	10	10	—
Sales of gas in place	(96)	(92)	(4)	(85)	(85)	—	(302)	(85)	(217)
At December 31	5,136	4,961	175	4,962	4,856	106	4,910	4,814	96
Proved developed reserves—Gas									
At January 1	3,706	3,605	101	3,685	3,591	94	3,834	3,474	360
At December 31	3,556	3,424	132	3,706	3,605	101	3,685	3,591	94
Proved developed and undeveloped reserves—Oil									
(thousands of barrels)									
At January 1	217,698	198,602	19,096	164,062	144,007	20,055	204,509	149,707	54,802
Changes in reserves:									
Extensions, discoveries and other additions	11,373	10,678	695	6,681	5,399	1,282	11,615	7,699	3,916
Revisions of previous estimates ⁽²⁾	38,010	40,629	(2,619)	63,884	65,264	(1,380)	(22,925)	(1,989)	(20,936)
Production	(24,947)	(23,923)	(1,024)	(15,575)	(14,714)	(861)	(13,783)	(11,258)	(2,525)
Purchases of oil in place	615	615	—	69	69	—	666	666	—
Sales of oil in place	(10,490)	(9,752)	(738)	(1,423)	(1,423)	—	(16,020)	(818)	(15,202)
At December 31 ⁽³⁾	232,259	216,849	15,410	217,698	198,602	19,096	164,062	144,007	20,055
Proved developed reserves—Oil									
At January 1	152,889	145,735	7,154	113,992	102,152	11,840	88,379	55,530	32,849
At December 31	180,779	173,718	7,061	152,889	145,735	7,154	113,992	102,152	11,840

(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 2006 U.S. revision is comprised of approximately 27.6 million barrels of natural gas liquids and 13 million barrels of oil/condensate. Natural gas liquids revisions were primarily the result of additional contractual changes with third-party gas processors in which we now take title to our processed natural gas liquids, and residue gas and liquids reserve amounts recognized under such contracts. Oil/condensate revisions were primarily the result of positive performance revisions at Gulf of Mexico deepwater locations. 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.

(3) Ending reserves for 2006, 2005 and 2004 included 114.6, 127.6 and 148.6 million barrels of oil/condensate, respectively, and 117.7, 90.1 and 15.5 million barrels of natural gas liquids, respectively.

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:

	2006			2005			2004		
	Total	United States	Canada	Total	United States	Canada	Total	United States	Canada
(millions)									
Future cash inflows ⁽¹⁾	\$38,326	\$36,604	\$1,722	\$63,004	\$61,112	\$1,892	\$36,819	\$35,735	\$1,084
Less:									
Future development costs ⁽²⁾	3,226	3,052	174	1,979	1,877	102	1,527	1,488	39
Future production costs	7,421	6,936	485	8,127	7,718	409	5,609	5,302	307
Future income tax expense	9,112	8,782	330	19,019	18,527	492	10,152	9,909	243
Future cash flows	18,567	17,834	733	33,879	32,990	889	19,531	19,036	495
Less annual discount (10% a year)	10,458	10,143	315	18,916	18,560	356	10,505	10,275	230
Standardized measure of discounted future net cash flows	\$ 8,109	\$ 7,691	\$ 418	\$14,963	\$14,430	\$ 533	\$ 9,026	\$ 8,761	\$ 265

(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 \$704 million, \$468 million and \$340 million for 2007, 2008 and 2009, respectively.

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:

	2006	2005	2004
(millions)			
Standardized measure of discounted future net cash flows at January 1	\$ 14,963	\$ 9,026	\$ 9,233
Changes in the year resulting from:			
Sales and transfers of gas and oil produced during the year, less production costs	(2,791)	(2,502)	(2,004)
Prices and production and development costs related to future production	(11,788)	8,929	1,656
Extensions, discoveries and other additions, less production and development costs	758	1,396	1,118
Previously estimated development costs incurred during the year	302	284	172
Revisions of previous quantity estimates	409	27	(734)
Accretion of discount	2,327	1,367	1,359
Income taxes	4,352	(3,659)	(291)
Other purchases and sales of proved reserves in place	(346)	140	(878)
Other (principally timing of production)	(77)	(45)	(605)
Standardized measure of discounted future net cash flows at December 31	\$ 8,109	\$14,963	\$ 9,026

NOTE 30. QUARTERLY FINANCIAL AND COMMON STOCK DATA (UNAUDITED)

A summary of our quarterly results of operations for the years ended December 31, 2006 and 2005 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors. As described in Note 9, we reported the operations of the Peaker facilities as discontinued operations beginning in the fourth quarter of 2006. Prior quarters for 2006 and 2005 have been recast to conform to this presentation. All differences between amounts presented below and those previously reported in our Quarterly Reports on Forms 10-Q during 2006 and 2005 are a result of reporting the results of operations of the Peaker facilities as discontinued operations.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
(millions, except per share amounts)					
2006					
Operating revenue	\$ 4,951	\$ 3,548	\$ 4,016	\$ 3,967	\$16,482
Income from operations	961	483	1,297	604	3,345
Income from continuing operations	539	167	658	199	1,563
Loss from discontinued operations	(5)	(6)	(4)	(168)	(183)
Net income	534	161	654	31	1,380
Basic EPS:					
Income from continuing operations	1.56	0.48	1.87	0.57	4.47
Loss from discontinued operations	(0.02)	(0.02)	(0.01)	(0.48)	(0.52)
Net income	1.54	0.46	1.86	0.09	3.95
Diluted EPS:					
Income from continuing operations	1.55	0.48	1.86	0.56	4.45
Loss from discontinued operations	(0.02)	(0.02)	(0.01)	(0.47)	(0.52)
Net income	1.53	0.46	1.85	0.09	3.93
Dividends paid per share	0.69	0.69	0.69	0.69	2.76
Common stock prices (high-low)	\$ 80.42- 68.88	\$ 76.02- 68.72	\$ 81.42- 74.44	\$ 84.44- 76.04	\$ 84.44- 68.72
2005					
Operating revenue	\$ 4,730	\$ 3,634	\$ 4,533	\$ 5,074	\$17,971
Income from operations	875	704	181	673	2,433
Income from continuing operations before cumulative effect of change in accounting principle	433	337	11	266	1,047
Income (Loss) from discontinued operations	(4)	(5)	4	(3)	(8)
Cumulative effect of change in accounting principle	—	—	—	(6)	(6)
Net income	429	332	15	257	1,033
Basic EPS:					
Income from continuing operations before cumulative effect of change in accounting principle	1.27	0.99	0.03	0.77	3.06
Income (Loss) from discontinued operations	(0.01)	(0.01)	0.01	(0.01)	(0.02)
Cumulative effect of change in accounting principle	—	—	—	(0.02)	(0.02)
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	1.26	0.99	0.03	0.77	3.04
Income (Loss) from discontinued operations	(0.01)	(0.02)	0.01	(0.01)	(0.02)
Cumulative effect of change in accounting principle	—	—	—	(0.02)	(0.02)
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

Our 2006 results include the impact of the following significant items:

- First quarter results include a \$94 million after-tax charge resulting from the write-off of certain regulatory assets related to the pending sale of Peoples and Hope, a \$222 million tax benefit from the partial reversal of previously recorded valuation allowances on certain federal and state tax loss carryforwards expected to be utilized to offset capital gain income that will be generated from the sale and the establishment of \$141 million of deferred tax liabilities associated with the excess of our financial reporting basis over the tax basis in the stock of Peoples and Hope. Results also include a \$76 million after-tax benefit resulting from favorable changes in the fair value of certain gas and oil derivatives that were de-designated as hedges following the 2005 hurricanes.
- Second quarter results include an \$85 million charge resulting from the impairment of a DCI investment for which no tax benefit has been recognized.
- Third quarter results include a \$171 million after-tax benefit from business interruption insurance revenue related to the 2005 hurricanes.
- Fourth quarter results include a \$164 million after-tax charge associated with the impairment of the Peaker facilities as a result of their pending sale.

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 the 2005 hurricanes, 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 the 2005 hurricanes.

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President and Chief Executive Officer,
Dominion Generation

Duane C. Radtke, 58

Executive Vice President
President and Chief Executive Officer,
Dominion Exploration & Production

David A. Christian, 52

Senior Vice President (Dominion Resources Services),
Nuclear Operations and Chief Nuclear Officer

Mary C. Doswell, 48

Senior Vice President and Chief Administrative Officer
President and Chief Executive Officer,
Dominion Resources Services

G. Scott Hetzer, 50

Senior Vice President and Treasurer

Steven A. Rogers, 45

Senior Vice President and Chief Accounting Officer

James L. Sanderlin, 65

Senior Vice President, Law

James F. Stutts, 62

Senior Vice President and General Counsel

SHAREHOLDER INFORMATION

Dominion Resources Services, Inc. is the transfer agent and registrar for Dominion's common stock. Our Shareholder Services staff provides personal assistance for any inquiries Monday through Friday from 9 a.m. to noon and from 1 p.m. to 4 p.m. (ET). In addition, automated information is available 24 hours a day through our voice response system.

1-800-552-4034 (toll free)

1-804-775-2500

Major press releases and other company information may be obtained by visiting our Web site at www.dom.com. Shareholders may also obtain account-specific information by visiting this site. To sign up for this service, visit www.dom.com and click on "Investors" and then select "Access Your Account Online." Once you have accessed the sign-in page, click on "First Time Visitor" in the upper-left corner of the screen and follow the directions for "New Member Sign Up." After you have signed up, you will be able to monitor your account, make changes and review your Dominion Direct® statements at your convenience.

Direct Stock Purchase Plan

You may buy Dominion common stock through Dominion Direct®. Please contact Shareholder Services for a prospectus and enrollment form or visit www.dom.com and click on "Investors."

Common Stock Listing

New York Stock Exchange

Trading symbol: D

Common Stock Price Range

	2006		2005	
	High	Low	High	Low
First Quarter	\$80.42	\$68.88	\$76.01	\$66.51
Second Quarter	76.02	68.72	76.87	67.75
Third Quarter	81.42	74.44	86.87	72.15
Fourth Quarter	84.44	76.04	86.97	73.50
Year	\$84.44	\$68.72	\$86.97	\$66.51

Dividends on Dominion common stock are paid as declared by the board. Dividends are typically paid on the 20th of March, June, September and December. Dividends can be paid by check or electronic deposit, or they may be reinvested.

On December 31, 2006, there were approximately 162,000 registered shareholders, including approximately 68,000 certificate holders.

Certifications

Dominion has submitted to the New York Stock Exchange (NYSE) a certification by its chief executive officer that he is not aware of any violation by the company of NYSE corporate governance listing standards. Dominion has also filed with the Securities and Exchange Commission certifications by its chief executive officer and chief financial officer as Exhibits 31.1 and 31.2 in its Annual Report on Form 10-K for the year ended December 31, 2006.

Annual Meeting

This year's Annual Meeting of Shareholders of Dominion Resources, Inc. will be held Friday, April 27, at 9:30 a.m. (ET) at 510 Atlantic Ave., Boston, Massachusetts.

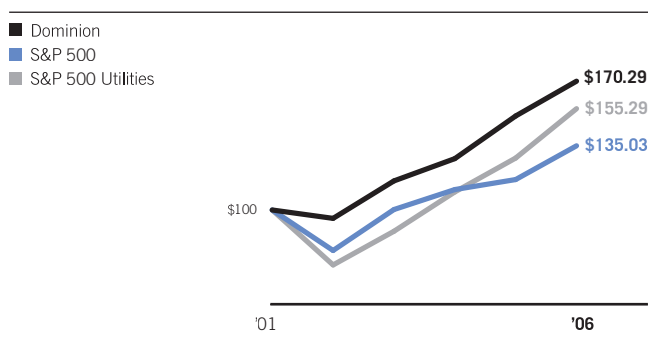
Performance Graph

This graph and table below show the five-year cumulative total return comparison between Dominion, the S&P 500 Index, and the S&P 500 Utilities Index.

Indexed Returns

Years Ending December	Base Period					
	2001	2002	2003	2004	2005	2006
Dominion	100	95.43	115.87	128.03	151.30	170.29
S&P 500	100	77.90	100.25	111.15	116.61	135.03
S&P 500 Utilities	100	70.01	88.39	109.85	128.35	155.29

COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN



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120 Tredegar Street
Richmond, Virginia 23219

Mailing Address

Dominion Resources, Inc.
P.O. Box 26532
Richmond, Virginia 23261-6532

Web Site

www.dom.com

Independent Registered Public Accounting Firm

Deloitte & Touche LLP
Richmond, Virginia

Shareholder Inquiries

Shareholder.Services@dom.com

Dominion Resources Services, Inc.
Shareholder Services
P.O. Box 26532
Richmond, Virginia 23261-6532

Additional Information

Copies of Dominion's Annual Report, Proxy Statement and reports on Form 10-K, Form 10-Q and Form 8-K are available without charge. These items can be viewed by visiting www.dom.com, or requests for these items can be made by writing to:

Corporate Secretary
Dominion Resources, Inc.
P.O. Box 26532
Richmond, Virginia 23261-6532

Electronic Reports

Our Proxy Statement and Annual Report are available electronically. Please refer to the proxy card that was mailed to shareholders with this annual report for more information.

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Design: Graphic Expression Inc., New York, New York

Printing: The Hennegan Company, Florence, Kentucky

Financial Typesetting: RR Donnelley

Photography: All photography by Cameron Davidson, except the portrait on page 13 by Mark Mitchell. The abstract image on the front cover and opening spread is from Getty Images.

Dominion Resources, Inc.

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