GILEAD SCIENCES INC
Form 10-Q
November 06, 2012

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2012
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________ to ________
Commission File No. 0-19731

GILEAD SCIENCES, INC.
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	94-3047598 (IRS Employer Identification No.)
333 Lakeside Drive, Foster City, California (Address of principal executive offices)	94404 (Zip Code)

650-574-3000
Registrant’s Telephone Number, Including Area Code

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a smaller reporting company)

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

Number of shares outstanding of the issuer's common stock, par value $0.001 per share, as of October 26, 2012: 757,648,151

GILEAD SCIENCES, INC.
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We own or have rights to various trademarks, copyrights and trade names used in our business, including the following: GILEAD®, GILEAD SCIENCES®, TRUVADA®, VIREAD®, HEPSERA®, AMBISOME®, EMTRIVA®, COMPLERA®, EVIPLERA®, STRIBILD™, VISTIDE®, LETAIRIS®, VOLIBRIS®, RANEXA®, CAYSTON® and RAPISCAN®. ATRIPLA® is a registered trademark belonging to Bristol-Myers Squibb & Gilead Sciences, LLC. LEXISCAN® is a registered trademark belonging to Astellas U.S. LLC. MACUGEN® is a registered trademark belonging to Valeant Pharmaceuticals International, Inc. SUSTIVA® is a registered trademark of Bristol-Myers Squibb Pharma Company. TAMIFLU® is a registered trademark belonging to Hoffmann-La Roche Inc. This report also includes other trademarks, service marks and trade names of other companies.

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
GILEAD SCIENCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	September 30, 2012 (unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$1,550,710	$9,883,777
Short-term marketable securities	144,775	16,491
Accounts receivable, net	1,766,091	1,951,167
Inventories	1,617,369	1,389,983
Deferred tax assets	222,572	208,155
Prepaid taxes	334,013	246,444
Prepaid expenses	100,674	95,922
Other current assets	144,175	126,846
Total current assets	5,880,379	13,918,785
Property, plant and equipment, net	856,184	774,406
Noncurrent portion of prepaid royalties	176,430	174,584
Noncurrent deferred tax assets	110,331	144,015
Long-term marketable securities	955,603	63,704
Intangible assets, net	11,735,354	1,062,864
Goodwill	1,078,919	1,004,102
Other noncurrent assets	170,629	160,674
Total assets	$20,963,829	$17,303,134
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$1,319,670	$1,206,052
Accrued government rebates	805,088	547,473
Accrued compensation and employee benefits	182,756	173,316
Income taxes payable	17,087	40,583
Other accrued liabilities	647,604	471,129
Deferred revenues	99,048	74,665
Current portion of long-term debt and other obligations, net	1,730,895	1,572
Total current liabilities	4,802,148	2,514,790
Long-term deferred revenues	20,836	31,870
Long-term debt, net	7,040,382	7,605,734
Long-term income taxes payable	128,655	135,655
Other long-term obligations	221,646	147,736
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, par value $0.001 per share; 5,000 shares authorized; none outstanding	—	—
Common stock, par value $0.001 per share; 2,800,000 shares authorized; 757,933 and 753,106 shares issued and outstanding at September 30, 2012 and December 31, 2011, respectively	758	753
Additional paid-in capital	5,435,242	4,903,143

Accumulated other comprehensive income	28,249	58,200
Retained earnings	3,139,393	1,776,760
Total Gilead stockholders’ equity	8,603,642	6,738,856
Noncontrolling interest	146,520	128,493
Total stockholders’ equity	8,750,162	6,867,349
Total liabilities and stockholders’ equity	$20,963,829	$17,303,134

See accompanying notes.

GILEAD SCIENCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues:				
Product sales	$2,357,978	$2,065,859	$6,887,560	$5,969,025
Royalty revenues	63,915	51,629	216,126	204,615
Contract and other revenues	4,704	4,172	10,546	11,367
Total revenues	2,426,597	2,121,660	7,114,232	6,185,007
Costs and expenses:				
Cost of goods sold	597,269	531,989	1,795,545	1,539,963
Research and development	465,831	290,066	1,320,286	826,915
Selling, general and administrative	319,583	295,927	1,095,209	895,764
Total costs and expenses	1,382,683	1,117,982	4,211,040	3,262,642
Income from operations	1,043,914	1,003,678	2,903,192	2,922,365
Interest expense	(89,322)	(43,097)	(275,010)	(130,420)
Other income (expense), net	(3,505)	14,406	(38,665)	40,216
Income before provision for income taxes	951,087	974,987	2,589,517	2,832,161
Provision for income taxes	280,052	237,449	774,877	704,861
Net income	671,035	737,538	1,814,640	2,127,300
Net loss attributable to noncontrolling interest	4,470	3,586	14,385	11,192
Net income attributable to Gilead	$675,505	$741,124	$1,829,025	$2,138,492
Net income per share attributable to Gilead common stockholders—basic	$0.89	$0.97	$2.42	$2.72
Shares used in per share calculation—basic	757,385	767,033	757,032	787,272
Net income per share attributable to Gilead common stockholders—diluted	$0.85	$0.95	$2.33	$2.66
Shares used in per share calculation—diluted	792,304	781,312	783,824	802,762

See accompanying notes.

GILEAD SCIENCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$671,035	$737,538	$1,814,640	$2,127,300
Other comprehensive income:				
Net foreign currency translation gain (loss)	5,090	(3,958)	7,346	(1,122)
Available-for-sale securities:				
Net unrealized gain (loss), net of tax impact of $(848) and $3,681 for the three months ended September 30, 2012 and 2011, and $(660) and $(2,634) for the nine months ended September 30, 2012 and 2011, respectively	1,476	(24,786)	1,146	(24,124)
Reclassifications to net income, net of tax impact of $1,396 and $(1,531) for the three months ended September 30, 2012 and 2011, and $849 and $(4,203) for the nine months ended September 30, 2012 and 2011, respectively	2,429	(2,656)	32,979	(7,160)
Net change	3,905	(27,442)	34,125	(31,284)
Cash flow hedges:				
Net unrealized gain (loss), net of tax impact of $3,180 and $(5,031) for the three months ended September 30, 2012 and 2011, and $460 and $3,366 for the nine months ended September 30, 2012 and 2011, respectively	(67,674)	107,044	(9,084)	(66,481)
Reclassification to net income, net of tax impact of $(1,760) and $1,978 for the three months ended September 30, 2012 and 2011, and $(3,156) and $2,655 for the nine months ended September 30, 2012 and 2011, respectively	(37,449)	42,094	(62,338)	52,433
Net change	(105,123)	149,138	(71,422)	(14,048)
Other comprehensive income (loss)	(96,128)	117,738	(29,951)	(46,454)
Comprehensive income	574,907	855,276	1,784,689	2,080,846
Comprehensive loss attributable to noncontrolling interest	4,470	3,586	14,385	11,192
Comprehensive income attributable to Gilead	$579,377	$858,862	$1,799,074	$2,092,038

See accompanying notes.

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GILEAD SCIENCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(in thousands)

	Nine Months Ended September 30,	
	2012	2011
Operating Activities:		
Net income	$1,814,640	$2,127,300
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation expense	60,488	53,232
Amortization expense	144,087	175,575
Stock-based compensation expense	151,598	145,775
Excess tax benefits from stock-based compensation	(64,955)	(30,255)
Tax benefits from employee stock plans	61,401	26,574
Deferred income taxes	21,374	43,415
Other	(2,037)	47,159
Changes in operating assets and liabilities:		
Accounts receivable, net	160,831	(221,393)
Inventories	(224,742)	(136,684)
Prepaid expenses and other assets	(109,550)	13,373
Accounts payable	146,458	257,805
Income taxes payable	(75,674)	85,177
Accrued liabilities	397,831	106,492
Deferred revenues	7,238	(32,642)
Net cash provided by operating activities	2,488,988	2,660,903
Investing Activities:		
Purchases of marketable securities	(1,148,751)	(4,161,322)
Proceeds from sales of marketable securities	130,463	3,498,720
Proceeds from maturities of marketable securities	25,975	506,513
Acquisitions, net of cash acquired	(10,751,636)	(588,608)
Purchases of other investments	(25,000)	—
Capital expenditures	(127,175)	(105,794)
Net cash used in investing activities	(11,896,124)	(850,491)
Financing Activities:		
Proceeds from issuances of senior notes, net of issuance costs	—	987,370
Proceeds from issuances of common stock	350,264	158,234
Proceeds from credit facilities, net of issuance costs	1,146,844	—
Proceeds from term loan, net of issuance costs	997,889	—
Repayments of term loan	(1,000,000)	—
Repayments of credit facility	(50,000)	—
Repurchases of common stock	(467,000)	(2,156,830)
Repayments of convertible senior notes	—	(649,987)
Repayments of other long-term obligations	(2,167)	(1,619)
Excess tax benefits from stock-based compensation	64,955	30,255
Contributions from (distributions to) noncontrolling interest	32,412	(130,474)
Net cash provided by (used in) financing activities	1,073,197	(1,763,051)
Effect of exchange rate changes on cash	872	(45,881)
Net change in cash and cash equivalents	(8,333,067)	1,480

Cash and cash equivalents at beginning of period	9,883,777	907,879
Cash and cash equivalents at end of period	$1,550,710	$909,359

See accompanying notes.

GILEAD SCIENCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1.SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying unaudited Condensed Consolidated Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles for interim financial information. The financial statements include all adjustments (consisting only of normal recurring adjustments) that the management of Gilead Sciences, Inc. (Gilead, we or us) believes are necessary for a fair presentation of the periods presented. These interim financial results are not necessarily indicative of results expected for the full fiscal year or for any subsequent interim period.

The accompanying Condensed Consolidated Financial Statements include the accounts of Gilead, our wholly-owned subsidiaries and our joint ventures with Bristol-Myers Squibb Company (BMS), for which we are the primary beneficiary. We record a noncontrolling interest in our Condensed Consolidated Financial Statements to reflect BMS's interest in the joint ventures. All intercompany transactions have been eliminated. The Condensed Consolidated Financial Statements include the results of companies acquired by us from the date of each acquisition for the applicable reporting periods.

The accompanying Condensed Consolidated Financial Statements and related financial information should be read in conjunction with the audited Consolidated Financial Statements and the related notes thereto for the year ended December 31, 2011, included in our Annual Report on Form 10-K filed with the U.S. Securities and Exchange Commission (SEC). Certain amounts within our Condensed Consolidated Financial Statements have been reclassified to conform to the current presentation.

Significant Accounting Policies, Estimates and Judgments

The preparation of these Condensed Consolidated Financial Statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures. On an ongoing basis, we evaluate our estimates, including critical accounting policies or estimates related to revenue recognition, intangible assets, allowance for doubtful accounts, prepaid royalties, clinical trial accruals, contingent consideration liabilities, stock-based compensation and our tax provision. We base our estimates on historical experience and various market specific and other relevant assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ significantly from these estimates.

Net Income Per Share Attributable to Gilead Common Stockholders

Basic net income per share attributable to Gilead common stockholders is calculated based on the weighted-average number of shares of our common stock outstanding during the period. Diluted net income per share attributable to Gilead common stockholders is calculated based on the weighted-average number of shares of our common stock outstanding and other dilutive securities outstanding during the period. The potential dilutive shares of our common stock resulting from the assumed exercise of outstanding stock options, performance shares and the assumed exercise of warrants relating to the convertible senior notes due in May 2013 (May 2013 Notes), May 2014 (May 2014 Notes) and May 2016 (May 2016 Notes) (collectively, the Convertible Notes) are determined under the treasury stock method.

Because the principal amount of the Convertible Notes will be settled in cash, only the conversion spread relating to the Convertible Notes is included in our calculation of diluted net income per share attributable to Gilead common stockholders. Our common stock resulting from the assumed settlement of the conversion spread of the Convertible Notes has a dilutive effect when the average market price of our common stock during the period exceeds the conversion prices of $38.10, $45.08 and $45.41 for the May 2013 Notes, May 2014 Notes and May 2016 Notes, respectively.

In 2011, our convertible senior notes due in May 2011 (May 2011 Notes) matured and the related warrants expired. As a result, we have only considered their impact for the period they were outstanding on our net income per share calculations. Our common stock resulting from the assumed settlement of the conversion spread of the May 2011 Notes had a dilutive effect when the average market price of our common stock during the period exceeded the conversion price of $38.75. During the nine months ended September 30, 2011, the average market price of our common stock exceeded the conversion price of the May 2011 Notes and the dilutive effect is included in the accompanying table. Warrants related to the May 2011 Notes had a dilutive effect when the average market price of our common stock during the period exceeded the warrants’ exercise price of $50.80. The average market price of our common stock during the nine months ended September 30, 2011 did not exceed the exercise price of the warrants related to the May 2011 Notes; therefore, these warrants did not have a dilutive effect on our net income per share for that period.

During the three and nine months ended September 30, 2012, the average market price of our common stock exceeded the conversion prices of the May 2013 Notes, May 2014 Notes and May 2016 Notes; therefore, the dilutive effects are included in the accompanying table. During the three and nine months ended September 30, 2011, the average market price of our common stock exceeded the conversion price of the May 2013 Notes and the dilutive effect is included in the accompanying table. During the three and nine months ended September 30, 2011, the average market price of our common stock did not exceed the conversion prices of the May 2014 Notes and May 2016 Notes and therefore, these notes did not have a dilutive effect on our net income per share for those periods.

Warrants relating to the May 2013 Notes, May 2014 Notes and May 2016 Notes have a dilutive effect when the average market price of our common stock during the period exceeds the warrants’ exercise prices of $53.90, $56.76 and $60.10, respectively. During the three months ended September 30, 2012, the average market price of our common stock exceeded the warrants’ exercise prices relating to the May 2013 Notes and May 2014 Notes and the dilutive effects are included in the accompanying table. During the three months ended September 30, 2012, the average market price of our common stock did not exceed the warrants’ exercise price relating to the May 2016 Notes and therefore, these warrants did not have a dilutive effect on our net income per share for that period. The average market prices of our common stock during the nine months ended September 30, 2012 and the three and nine months ended September 30, 2011 did not exceed the warrants’ exercise prices relating to any of the Convertible Notes; therefore, these warrants did not have a dilutive effect on our net income per share for those periods.

Stock options to purchase approximately 2.1 million and 5.7 million weighted-average shares of our common stock were outstanding during the three and nine months ended September 30, 2012, but were not included in the computation of diluted net income per share attributable to Gilead common stockholders because their effect was antidilutive. Stock options to purchase approximately 21.0 million and 21.4 million weighted-average shares of our common stock were outstanding during the three and nine months ended September 30, 2011, respectively, but were not included in the computation of diluted net income per share attributable to Gilead common stockholders because their effect was antidilutive.

The following table is a reconciliation of the numerator and denominator used in the calculation of basic and diluted net income per share attributable to Gilead common stockholders (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Numerator:				
Net income attributable to Gilead	$675,505	$741,124	$1,829,025	$2,138,492
Denominator:				
Weighted-average shares of common stock outstanding used in the calculation of basic net income per share attributable to Gilead common stockholders	757,385	767,033	757,032	787,272
Effect of dilutive securities:				
Stock options and equivalents	16,239	13,548	15,463	14,452
Conversion spread related to the May 2011 Notes	—	—	—	253
Conversion spread related to the May 2013 Notes	5,723	731	4,475	785
Conversion spread related to the May 2014 Notes	5,930	—	3,529	—
Conversion spread related to the May 2016 Notes	5,726	—	3,325	—
Warrants related to the Convertible Notes	1,301	—	—	—
Weighted-average shares of common stock outstanding used in the calculation of diluted net income per share attributable to Gilead common stockholders	792,304	781,312	783,824	802,762

Concentrations of Risk

We are subject to credit risk from our portfolio of cash equivalents and marketable securities. Under our investment policy, we limit amounts invested in such securities by credit rating, maturity, industry group, investment type and issuer, except for securities issued by the U.S. government. We are not exposed to any significant concentrations of credit risk from these financial instruments. The goals of our investment policy, in order of priority, are as follows: safety and preservation of principal and diversification of risk; liquidity of investments sufficient to meet cash flow requirements; and a competitive after-tax rate of return.

We are also subject to credit risk from our accounts receivable related to our product sales. The majority of our trade accounts receivable arises from product sales in the United States and Europe.

During the second quarter of 2012, we received payment on $460.6 million in past due accounts receivable from customers based in Spain. Included in this amount were proceeds from a factoring arrangement where we sold receivables with a carrying value of $319.8 million, net of the allowance for doubtful accounts. We received proceeds of $349.7 million and recorded a gain of $29.9 million, resulting primarily from the reversal of the related allowance for doubtful accounts. This gain was recorded as an offset to selling, general and administrative (SG&A) expenses in our Condensed Consolidated Statement of Income. Subsequent to this transaction, we have had no continuing involvement with the transferred receivables, which were derecognized at the time of the sale.

As of September 30, 2012, our accounts receivable in Southern Europe, specifically Greece, Italy, Portugal and Spain, totaled approximately $826.8 million, of which $314.9 million were greater than 120 days past due and $84.8 million were greater than 365 days past due. To date, we have not experienced significant losses with respect to the collection of our accounts receivable. We believe that our allowance for doubtful accounts was adequate at September 30, 2012.

Recent Accounting Pronouncements

In July 2012, the Financial Accounting Standards Board (FASB) issued new accounting guidance intended to simplify the testing of indefinite-lived intangible assets for impairment. Entities will be allowed the option to first perform a qualitative assessment on impairment for indefinite-lived intangible assets to determine whether a quantitative assessment is necessary. This guidance is effective for impairment tests performed in the interim and annual periods for fiscal years beginning after September 15, 2012. Early adoption is permitted. The adoption of this guidance is not expected to have a material impact on our Consolidated Financial Statements.

2. FAIR VALUE MEASUREMENTS

We determine the fair value of financial and non-financial assets and liabilities using the fair value hierarchy, which establishes three levels of inputs that may be used to measure fair value, as follows:

- Level 1 inputs which include quoted prices in active markets for identical assets or liabilities;
- Level 2 inputs which include observable inputs other than Level 1 inputs, such as quoted prices for similar assets or liabilities; quoted prices for identical or similar assets or liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the asset or liability. For our marketable securities, we review trading activity and pricing as of the measurement date. When sufficient quoted pricing for identical securities is not available, we use market pricing and other observable market inputs for similar securities obtained from various third-party data providers. These inputs either represent quoted prices for similar assets in active markets or have been derived from observable market data; and
- Level 3 inputs which include unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the underlying asset or liability. Level 3 assets and liabilities include those whose fair value measurements are determined using pricing models, discounted cash flow methodologies or similar valuation techniques, as well as significant management judgment or estimation.

Our financial instruments consist principally of cash and cash equivalents, marketable securities, accounts receivable, foreign currency exchange forward and option contracts, accounts payable, and short-term and long-term debt. Cash and cash equivalents, marketable securities and foreign currency exchange contracts that hedge accounts receivable and forecasted product sales are reported at their respective fair values on our Condensed Consolidated Balance Sheets. The carrying value and fair value of the Convertible Notes were $2.99 billion and $4.98 billion, respectively, as of September 30, 2012. The carrying value and fair value of the Convertible Notes were $2.92 billion and $3.53 billion, respectively, as of December 31, 2011.

During the first quarter of 2011, we issued senior unsecured notes due in April 2021 (April 2021 Notes) in a registered offering for an aggregate principal amount of $1.00 billion. The carrying value and fair value of the April 2021 Notes were $992.7 million and $1.14 billion, respectively, as of September 30, 2012. The carrying value and fair value of the April 2021 Notes were $992.1 million and $1.06 billion, respectively, as of December 31, 2011. In December 2011, we issued senior unsecured notes due in December 2014 (December 2014 Notes), December 2016 (December 2016 Notes), December 2021 (December 2021 Notes) and December 2041 (December 2041 Notes) in a registered offering for an aggregate principal amount of $3.70 billion. The carrying value and fair value of these notes were $3.69 billion and $4.21 billion, respectively, as of September 30, 2012. The carrying value and fair value of these notes were $3.69 billion and $3.93 billion, respectively, as of December 31, 2011. The fair values of the Convertible Notes and senior unsecured notes were determined using Level 2 inputs based on their quoted market values.

The remaining financial instruments are reported on our Condensed Consolidated Balance Sheets at amounts that approximate current fair values.

The following table summarizes, for assets or liabilities recorded at fair value, the respective fair value and the classification by level of input within the fair value hierarchy defined above (in thousands):

	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Debt securities:								
U.S. treasury securities	$308,309	$—	$—	$308,309	$—	$—	$—	$—
Money market funds	1,110,384	—	—	1,110,384	7,455,982	—	—	7,455,982
Certificates of deposit	—	—	—	—	—	1,139,982	—	1,139,982
U.S. government agencies and FDIC guaranteed securities	—	353,596	—	353,596	—	—	—	—
Non-U.S. government securities	—	—	—	—	—	—	24,741	24,741
Municipal debt securities	—	8,106	—	8,106	—	—	—	—
Corporate debt securities	—	334,886	—	334,886	—	404,989	—	404,989
Residential mortgage and asset-backed securities	—	95,481	—	95,481	—	—	—	—
Student loan-backed securities	—	—	—	—	—	—	46,952	46,952
Total debt securities	1,418,693	792,069	—	2,210,762	7,455,982	1,544,971	71,693	9,072,646
Equity securities	—	—	—	—	8,503	—	—	8,503
Derivatives	—	57,298	—	57,298	—	100,475	—	100,475
	$1,418,693	$849,367	$—	$2,268,060	$7,464,485	$1,645,446	$71,693	$9,181,624
Liabilities:								
Contingent consideration	$—	$—	$199,707	$199,707	$—	$—	$135,591	$135,591
Derivatives	—	34,135	—	34,135	—	5,710	—	5,710
	$—	$34,135	$199,707	$233,842	$—	$5,710	$135,591	$141,301

Level 2 Inputs

We estimate the fair values of our government related debt, corporate debt, residential mortgage and asset-backed securities by taking into consideration valuations obtained from third-party pricing services. The pricing services utilize industry standard valuation models, including both income- and market-based approaches, for which all significant inputs are observable, either directly or indirectly, to estimate fair value. These inputs include reported trades of and broker/dealer quotes on the same or similar securities; issuer credit spreads; benchmark securities; prepayment/default projections based on historical data; and other observable inputs.

Substantially all of our foreign currency derivatives contracts have maturities primarily over an 18 month time horizon and all are with counterparties that have a minimum credit rating of A- or equivalent by Standard & Poor's, Moody's Investors Service, Inc. or Fitch, Inc. We estimate the fair values of these contracts by taking into consideration valuations obtained from a third-party valuation service that utilizes an income-based industry standard valuation model for which all significant inputs are observable, either directly or indirectly. These inputs include foreign currency rates, London Interbank Offered Rates (LIBOR) and swap rates. These inputs, where applicable, are at commonly quoted intervals.

Level 3 Inputs

Assets measured at fair value using Level 3 inputs were comprised of auction rate securities and Greek bonds within our available-for-sale investment portfolio. Our policy is to recognize transfers into or out of Level 3 classification as of the actual date of the event or change in circumstances that caused the transfer. The following table provides a rollforward of the fair value of our assets measured using Level 3 inputs (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Fair value, beginning of period	$43,872	$104,145	$71,693	$80,365
Total realized and unrealized gains (losses) included in:				
Other income (expense), net	—	1,707	(40,096)	4,578
Other comprehensive income, net	(1,618)	(22,681)	32,630	(28,375)
Sales of marketable securities	(42,254)	(1,350)	(64,227)	(28,630)
Transfers into Level 3	—	—	—	53,883
Fair value, end of period	$—	$81,821	$—	$81,821

Auction Rate Securities

The underlying assets of the auction rate securities consisted of student loans. Although auction rate securities are typically measured using Level 2 inputs, the failure of auctions and the lack of market activity and liquidity experienced since the beginning of 2008 required that these securities be measured using Level 3 inputs. The fair value of the auction rate securities was determined using a discounted cash flow model that considered projected cash flows for the issuing trusts, underlying collateral and expected yields. Projected cash flows were estimated based on the underlying loan principal, bonds outstanding and payout formulas. The weighted-average life over which the cash flows were projected considered the collateral composition of the securities and related historical and projected prepayments.

During the third quarter of 2012, we sold our remaining portfolio of auction rate securities. As a result of the sale, we received total proceeds of $37.3 million and resulted in a $3.8 million loss which was recognized in other income (expense), net on our Condensed Consolidated Statement of Income.

As of December 31, 2011, our auction rate securities were recorded in long-term marketable securities on our Condensed Consolidated Balance Sheets.

Greek Government Bonds

In 2010, the Greek government agreed to settle the majority of its aged outstanding accounts receivable with zero-coupon bonds, which were expected to trade at a discount to face value. We estimated the fair value of the Greek zero-coupon bonds using Level 3 inputs due to the then current lack of market activity and liquidity. The discount rates used in our fair value model for these bonds were based on credit default swap rates. During the first quarter of 2012, the Greek government restructured its sovereign debt which impacted all holders of Greek bonds. As a result, we recorded a $40.1 million loss related to the debt restructuring as part of other income (expense), net on our Condensed Consolidated Statement of Income and exchanged the Greek bonds for new securities, which we liquidated during the first quarter of 2012.

As of December 31, 2011, our Greek government-issued bonds were recorded in short-term and long-term marketable securities on our Condensed Consolidated Balance Sheets.

Contingent Consideration Liabilities

In connection with certain acquisitions, we may be required to pay future consideration that is contingent upon the achievement of specified development, regulatory approval or sales-based milestone events. We estimate the fair value of the contingent consideration liabilities on the acquisition date and each reporting period thereafter using a probability-weighted income approach, which reflects the probability and timing of future payments. This fair value measurement is based on significant Level 3 inputs such as the anticipated timelines and probability of achieving development, regulatory approval or sales-based milestone events and projected revenues. The resulting probability-weighted cash flows are discounted using credit-risk adjusted interest rates.

Each reporting period thereafter, we revalue these obligations by performing a review of the assumptions listed above and record increases or decreases in the fair value of these contingent consideration obligations in research and development expense within our Condensed Consolidated Statements of Income until such time that the related product candidate reaches commercialization. In the absence of any significant changes in key assumptions, the quarterly determination of fair values of these contingent consideration obligations would primarily reflect the passage of time.

Significant judgment is employed in determining Level 3 inputs and fair value measurements as of the acquisition date and for each subsequent period. Updates to assumptions could have a significant impact on our results of operations in any given period and actual results may differ from estimates. For example: significant increases in the probability of achieving a milestone or projected revenues would result in a significantly higher fair value measurement while significant decreases in the estimated probability of achieving a milestone or projected revenues would result in a significantly lower fair value measurement. Significant increases in the discount rate or in the anticipated timelines would result in a significantly lower fair value measurement while significant decreases in the discount rate or anticipated timelines would result in a significantly higher fair value measurement.

The potential contingent consideration payments resulting from development or regulatory approval based milestones related to our CGI Pharmaceuticals, Inc. and Calistoga Pharmaceuticals, Inc. (Calistoga) acquisitions range from no payment if none of the milestones are achieved, to an estimated maximum of $254 million (undiscounted), of which we had accrued $157.7 million as of September 30, 2012 and $120.2 million as of September 30, 2011. Potential future payments resulting from the acquisition of Arresto Biosciences, Inc. (Arresto) relate to royalty obligations on future sales once specified sales-based milestones are achieved.

The following table provides a rollforward of our contingent consideration liabilities, which are recorded as part of other long-term obligations in our Condensed Consolidated Balance Sheets (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Balance, beginning of period	$140,897	$126,690	$135,591	$11,100
Additions from new acquisitions	—	—	—	116,008
Net changes in valuation	58,810	1,615	64,116	1,197
Balance, end of period	$199,707	$128,305	$199,707	$128,305

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3. AVAILABLE-FOR-SALE SECURITIES

The following table is a summary of available-for-sale debt and equity securities included in cash and cash equivalents or marketable securities in our Condensed Consolidated Balance Sheets. During the first quarter of 2012, we liquidated a portion of our investment portfolio to partially fund the acquisition of Pharmasset, Inc. (Pharmasset) which was completed in January 2012. Estimated fair values of available-for-sale securities are generally based on prices obtained from commercial pricing services (in thousands):

	September 30, 2012				December 31, 2011			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Debt securities:								
U.S. treasury securities	$307,961	$368	$(20)	$308,309	$—	$—	$—	$—
Money market funds	1,110,384	—	—	1,110,384	7,455,982	—	—	7,455,982
Certificates of deposit	—	—	—	—	1,140,000	—	(18)	1,139,982
U.S. government agencies securities	353,152	474	(30)	353,596	—	—	—	—
Non-U.S. government securities	—	—	—	—	55,246	—	(30,505)	24,741
Municipal debt securities	8,075	31	—	8,106	—	—	—	—
Corporate debt securities	333,491	1,429	(34)	334,886	404,994	—	(5)	404,989
Residential mortgage-backed and asset-backed securities	95,465	175	(159)	95,481	—	—	—	—
Student loan-backed securities	—	—	—	—	51,500	—	(4,548)	46,952
Total debt securities	2,208,528	2,477	(243)	2,210,762	9,107,722	—	(35,076)	9,072,646
Equity securities	—	—	—	—	1,451	7,052	—	8,503
Total	$2,208,528	$2,477	$(243)	$2,210,762	$9,109,173	$7,052	$(35,076)	$9,081,149

The following table summarizes the classification of the available-for-sale debt and equity securities on our Condensed Consolidated Balance Sheets (in thousands):

	September 30, 2012	December 31, 2011
Cash and cash equivalents	$1,110,384	$9,000,954
Short-term marketable securities	144,775	16,491
Long-term marketable securities	955,603	63,704
Total	$2,210,762	$9,081,149

The following table summarizes our portfolio of available-for-sale debt securities by contractual maturity (in thousands):

	September 30, 2012	
	Amortized Cost	Fair Value

Less than one year	$1,245,135	$1,245,165
Greater than one year but less than five years	927,079	929,196
Greater than five years but less than ten years	17,151	17,229
Greater than ten years	19,163	19,172
Total	$2,208,528	$2,210,762

The following table summarizes the gross realized gains and losses related to sales of marketable securities (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Gross realized gains on sales	$25	$4,830	$10,124	$13,784
Gross realized losses on sales	$(3,850)	$(644)	$(43,951)	$(2,421)

The cost of securities sold was determined based on the specific identification method.

The following table summarizes our available-for-sale debt securities that were in a continuous unrealized loss position, but were not deemed to be other-than-temporarily impaired (in thousands):

	Less Than 12 Months		12 Months or Greater		Total	
	Gross Unrealized Losses	Estimated Fair Value	Gross Unrealized Losses	Estimated Fair Value	Gross Unrealized Losses	Estimated Fair Value
September 30, 2012						
Debt securities:						
U.S. treasury securities	$(20)	$67,983	$—	$—	$(20)	$67,983
Certificates of deposit	—	—	—	—	—	—
U.S. government agencies securities	(30)	41,856	—	—	(30)	41,856
Non-U.S. government securities	—	—	—	—	—	—
Corporate debt securities	(34)	42,456	—	—	(34)	42,456
Residential mortgage-backed and asset-backed securities	(159)	43,211	—	—	(159)	43,211
Student loan-backed securities	—	—	—	—	—	—
Total	$(243)	$195,506	$—	$—	$(243)	$195,506
December 31, 2011						
Debt securities:						
U.S. treasury securities	$—	$—	$—	$—	$—	$—
Certificates of deposit	(18)	1,019,982	—	—	(18)	1,019,982
U.S. government agencies securities	—	—	—	—	—	—
Non-U.S. government securities	(30,505)	24,741	—	—	(30,505)	24,741
Corporate debt securities	(5)	224,989	—	—	(5)	224,989
Residential mortgage-backed and asset-backed securities	—	—	—	—	—	—
Student loan-backed securities	—	—	(4,548)	46,952	(4,548)	46,952
Total	$(30,528)	$1,269,712	$(4,548)	$46,952	$(35,076)	$1,316,664

As of September 30, 2012 and December 31, 2011, we held a total of 39 and 42 securities, respectively, that were in an unrealized loss position.

4. DERIVATIVE FINANCIAL INSTRUMENTS

We operate in foreign countries, which exposes us to market risk associated with foreign currency exchange rate fluctuations between the U.S. dollar and various foreign currencies, the most significant of which is the Euro. In order to manage this risk, we hedge a portion of our foreign currency exposures related to outstanding monetary assets and liabilities as well as forecasted product sales using foreign currency exchange forward and option contracts. In general, the market risk related to these contracts is offset by corresponding gains and losses on the hedged transactions. The credit risk associated with these contracts is driven by changes in interest and currency exchange rates and, as a result, varies over time. We work only with major banks and closely monitor current market conditions, which limits the risk that counterparties to our contracts may be unable to perform. We also limit our risk of loss by entering into contracts that permit net settlement at maturity. Therefore, our overall risk of loss in the event of a counterparty default is limited to the amount of any unrecognized gains on outstanding contracts (i.e., those contracts that have a positive fair value) at the date of default. We do not enter into derivative contracts for trading purposes, nor do we hedge our net investment in any of our foreign subsidiaries.

We hedge our exposure to foreign currency exchange rate fluctuations for certain monetary assets and liabilities of our foreign subsidiaries that are denominated in a non-functional currency. The derivative instruments we use to hedge this exposure are not designated as hedges, and as a result, changes in their fair value are recorded in other income (expense), net on our Condensed Consolidated Statements of Income.

We hedge our exposure to foreign currency exchange rate fluctuations for forecasted product sales that are denominated in a non-functional currency. The derivative instruments we use to hedge this exposure are designated as cash flow hedges and have maturity dates of 18 months or less. Upon executing a hedging contract and quarterly thereafter, we assess prospective hedge effectiveness using a regression analysis which calculates the change in cash flow as a result of the hedge instrument. On a monthly basis, we assess retrospective hedge effectiveness using a dollar offset approach. We exclude time value from our effectiveness testing and recognize changes in the time value of the hedge in other income (expense), net. The effective component of our hedge is recorded as an unrealized gain or loss on the hedging instrument in accumulated other comprehensive income (OCI) within stockholders' equity. When the hedged forecasted transaction occurs, the hedge is de-designated and the unrealized gains or losses are reclassified into product sales. The majority of gains and losses related to the hedged forecasted transactions reported in accumulated OCI at September 30, 2012 will be reclassified to product sales within 12 months.

We had notional amounts on foreign currency exchange contracts outstanding of $3.27 billion and $4.03 billion at September 30, 2012 and December 31, 2011, respectively.

The following table summarizes information about the fair values of derivative instruments on our Condensed Consolidated Balance Sheets (in thousands):

	September 30, 2012			
	Asset Derivatives		Liability Derivatives	
	Classification	Fair Value	Classification	Fair Value
Derivatives designated as hedges:				
Foreign currency exchange contracts	Other current assets	$56,602	Other accrued liabilities	$ 25,787
Foreign currency exchange contracts	Other noncurrent assets	608	Other long-term obligations	8,317
Total derivatives designated as hedges		57,210		34,104
Derivatives not designated as hedges:				
Foreign currency exchange contracts	Other current assets	85	Other accrued liabilities	31
Total derivatives not designated as hedges		85		31
Total derivatives		$57,295		$ 34,135

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	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
	Classification	Fair Value	Classification	Fair Value
Derivatives designated as hedges:				
Foreign currency exchange contracts	Other current assets	$77,066	Other accrued liabilities	$ 5,052
Foreign currency exchange contracts	Other noncurrent assets	23,169	Other long-term obligations	620
Total derivatives designated as hedges		100,235		5,672
Derivatives not designated as hedges:				
Foreign currency exchange contracts	Other current assets	240	Other accrued liabilities	38
Total derivatives not designated as hedges		240		38
Total derivatives		$100,475		$ 5,710

The following table summarizes the effect of our foreign currency exchange contracts on our Condensed Consolidated Statements of Income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Derivatives designated as hedges:				
Net gains (losses) recognized in OCI (effective portion)	$(70,855)	$107,871	$(7,730)	$(66,236)
Net gains (losses) reclassified from accumulated OCI into product sales (effective portion)	$39,209	$(44,072)	$65,494	$(55,088)
Net gains (losses) recognized in other income (expense), net (ineffective portion and amounts excluded from effectiveness testing)	$(1,688)	$(7,759)	$(8,444)	$(10,825)
Derivatives not designated as hedges:				
Net gains (losses) recognized in other income (expense), net	$(31,973)	$86,781	$34,445	$(33,409)

There were no material amounts recorded in other income (expense), net, for the three or nine months ended September 30, 2012 and 2011 as a result of the discontinuance of cash flow hedges.

5. ACQUISITION OF PHARMASSET, INC.

On January 17, 2012, we completed the acquisition of Pharmasset, a publicly-held clinical-stage pharmaceutical company committed to discovering, developing and commercializing novel drugs to treat viral infections. Pharmasset's primary focus was the development of oral therapeutics for the treatment of HCV infection. Pharmasset's lead compound, now known as GS-7977, is a nucleotide analog which, as of January 2012, was being evaluated in Phase 2 and Phase 3 clinical studies for the treatment of HCV infection across genotypes. We believe the acquisition of Pharmasset provides us with an opportunity to complement our existing HCV portfolio and helps advance our effort to develop all-oral regimens for the treatment of HCV.

We acquired all of the outstanding shares of common stock of Pharmasset for $137 per share in cash through a tender offer and subsequent merger under the terms of an agreement and plan of merger entered into in November 2011. The aggregate cash payment to acquire all of the outstanding shares of common stock was $11.1 billion. We financed the transaction with approximately $5.2 billion in cash on hand, $3.7 billion in senior unsecured notes issued in December 2011 and $2.2 billion in bank debt issued in January 2012.

The Pharmasset acquisition was accounted for as a business combination. The results of operations of Pharmasset have been included in our Condensed Consolidated Statement of Income since January 13, 2012, the date on which we acquired approximately 88% of the outstanding shares of common stock of Pharmasset, cash consideration was transferred, and as a result, we obtained effective control of Pharmasset. The acquisition was completed on January 17, 2012, at which time Pharmasset became a wholly-owned subsidiary of Gilead and was integrated into our operations. As we do not track earnings results by product candidate or therapeutic area, we do not maintain separate earnings results for the acquired Pharmasset business.

The following table summarizes the components of the cash paid to acquire Pharmasset (in thousands):

Total consideration transferred	$10,858,372
Stock-based compensation expense	193,937
Total cash paid	$11,052,309

The $11.1 billion cash payment consisted of a $10.38 billion cash payment to the outstanding common stockholders as well as a $668.3 million cash payment to option holders under the Pharmasset stock option plans. The $10.38 billion cash payment to the outstanding common stockholders and $474.3 million of the cash payment to the option holders under the Pharmasset stock option plans were accounted for as consideration transferred. The remaining $193.9 million of cash payment was accounted for as stock-based compensation expense resulting from the accelerated vesting of Pharmasset employee options immediately prior to the acquisition.

The following table summarizes the acquisition date fair values of assets acquired and liabilities assumed, and the consideration transferred (in thousands):

Intangible assets - in-process research and development	$10,720,000
Cash and cash equivalents	106,737
Other assets acquired (liabilities assumed), net	(43,182)
Total identifiable net assets	10,783,555
Goodwill	74,817
Total consideration transferred	$10,858,372

In-Process Research and Development (IPR&D)

The estimated fair value of the acquired IPR&D related to GS-7977 was $10.72 billion, which was determined using a probability-weighted income approach that discounts expected future cash flows to present value. The estimated net cash flows were discounted using a discount rate of 12%, which is based on the estimated weighted-average cost of capital for companies with profiles similar to that of Pharmasset. This rate is comparable to the estimated internal rate of return for the acquisition and represents the rate that market participants would use to value the intangible asset. The projected cash flows from GS-7977 were based on key assumptions such as: the time and resources needed to complete its development considering its stage of development on the acquisition date, the probability of obtaining approval from the U.S. Food and Drug Administration (FDA) and other regulatory agencies, estimates of revenues and operating profits, the life of the potential commercialized product and other associated risks related to the viability of and potential alternative treatments in future target markets. Intangible assets related to IPR&D projects are considered to be indefinite-lived assets until the completion or abandonment of the associated research and development (R&D) efforts.

Goodwill

The $74.8 million of goodwill represents the excess of the consideration transferred over the fair values of assets acquired and liabilities assumed and is attributable to the synergies expected from combining our R&D operations with Pharmasset's. None of the goodwill is expected to be deductible for income tax purposes.

Stock-Based Compensation Expense

The stock-based compensation expense recognized for the accelerated vesting of employee options immediately prior to the acquisition was reported in our Condensed Consolidated Statement of Income as follows (in thousands):

	Nine Months Ended September 30, 2012
Research and development expense	$100,149
Selling, general and administrative expense	93,788
Total stock-based compensation expense	$193,937

Other Costs

Other costs incurred in connection with the acquisition include (in thousands):

	Nine Months Ended September 30, 2012	Three Months Ended December 31, 2011
Transaction costs (e.g. investment advisory, legal and accounting fees)	$10,463	$28,461
Bridge financing costs	7,333	23,817
Restructuring costs	14,929	—
Total other costs	$32,725	$52,278

The following table summarizes these costs by the line item in the Condensed Consolidated Statement of Income in which these costs were recognized (in thousands).

	Nine Months Ended September 30, 2012	Three Months Ended December 31, 2011
Research and development expense	$7,710	$—
Selling, general and administrative expense	17,682	28,461
Interest expense	7,333	23,817
Total other costs	$32,725	$52,278

Pro Forma Information

The following unaudited pro forma information presents the combined results of operations of Gilead and Pharmasset as if the acquisition of Pharmasset had been completed on January 1, 2011, with adjustments to give effect to pro forma events that are directly attributable to the acquisition. The unaudited pro forma results do not reflect any operating efficiencies or potential cost savings which may result from the consolidation of the operations of Gilead and Pharmasset. Accordingly, these unaudited pro forma results are presented for informational purposes only and are not necessarily indicative of what the actual results of operations of the combined company would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of future results of operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Total revenues	$2,426,597	$2,121,660	$7,114,232	$6,185,007
Net income attributable to Gilead	$680,483	$677,662	$1,983,004	$1,756,056

The unaudited pro forma consolidated results include non-recurring pro forma adjustments that assume the acquisition occurred on January 1, 2011. Stock-based compensation expenses of $193.9 million incurred during the nine months ended September 30, 2012 were included in the net income attributable to Gilead for the nine months ended September 30, 2011. Other costs of $17.8 million incurred during the nine months ended September 30, 2012 were included in the net income attributable to Gilead for the nine months ended September 30, 2011. Of the $17.8 million, $0.3 million was incurred during the three months ended September 30, 2012. Other costs of $52.3 million incurred during the three months ended December 31, 2011 were included in net income attributable to Gilead for the nine months ended September 30, 2011.

6. INVENTORIES

Inventories are summarized as follows (in thousands):

	September 30, 2012	December 31, 2011
Raw materials	$826,651	$697,621
Work in process	378,988	466,499
Finished goods	411,730	225,863

Total	$1,617,369	$1,389,983

As of September 30, 2012 and December 31, 2011, we held $1.18 billion and $995.7 million of efavirenz in inventory, respectively, which was purchased from BMS at BMS's estimated net selling price of efavirenz.

7. INTANGIBLE ASSETS AND GOODWILL

The following table summarizes the carrying amount of our intangible assets and goodwill (in thousands):

	September 30, 2012	December 31, 2011
Indefinite-lived intangible assets	$10,986,200	$266,200
Finite-lived intangible assets	749,154	796,664
Total intangible assets	11,735,354	1,062,864
Goodwill	1,078,919	1,004,102
Total intangible assets and goodwill	$12,814,273	$2,066,966

Indefinite-Lived Intangible Assets

In January 2012, we acquired $10.72 billion of purchased IPR&D as part of our acquisition of Pharmasset that we have classified as indefinite-lived intangible assets (See Note 5).

As of December 31, 2011, we had indefinite-lived intangible assets of $266.2 million, which consisted of $117.0 million and $149.2 million of purchased IPR&D from our acquisitions of Arresto and Calistoga, respectively.

Finite-Lived Intangible Assets

The following table summarizes our finite-lived intangible assets (in thousands):

	September 30, 2012		December 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible asset - Ranexa	$688,400	$124,114	$688,400	$97,099
Intangible asset - Lexiscan	262,800	89,030	262,800	69,723
Other	24,995	13,897	24,995	12,709
Total	$976,195	$227,041	$976,195	$179,531

Amortization expense related to intangible assets was included in cost of goods sold in our Condensed Consolidated Statements of Income and totaled $15.8 million and $47.5 million for the three and nine months ended September 30, 2012, respectively, and $17.4 million and $52.2 million for the three and nine months ended September 30, 2011, respectively.

As of September 30, 2012, the estimated future amortization expense associated with our intangible assets for the remaining three months of 2012 and each of the five succeeding fiscal years are as follows (in thousands):

Fiscal Year	Amount
2012 (remaining three months)	$15,836
2013	64,283
2014	66,735
2015	73,261
2016	100,048
2017	132,786
Total	$452,949

Goodwill

The following table summarizes the changes in the carrying amount of goodwill (in thousands):

Balance at December 31, 2011	$1,004,102
Goodwill resulting from the acquisition of Pharmasset	74,817
Balance at September 30, 2012	$1,078,919

8. COLLABORATIVE ARRANGEMENTS

From time to time, as a result of entering into strategic collaborations, we may hold investments in non-public companies. We review our interests in investee companies for consolidation and/or appropriate disclosure based on applicable guidance. For variable interest entities (VIEs), we may be required to consolidate an entity if the contractual terms of the arrangement essentially provide us with control over the entity, even if we do not have a majority voting interest. We assess whether we are the primary beneficiary of a VIE based on our power to direct the activities of the VIE that most significantly impact the VIE's economic performance and our obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. As of September 30, 2012, we determined that certain of our investee companies are VIEs; however, other than with respect to our joint ventures with BMS, we do not control and are not the primary beneficiary with respect to such investees; therefore, we do not consolidate these investees.

Bristol-Myers Squibb Company

North America

In 2004, we entered into a collaboration arrangement with BMS in the United States to develop and commercialize a single tablet regimen containing our Truvada and BMS's Sustiva (efavirenz), which we sell as Atripla. The collaboration is structured as a joint venture and operates as a limited liability company named Bristol-Myers Squibb & Gilead Sciences, LLC, which we consolidate. The ownership interests of the joint venture and thus the sharing of product revenue and costs reflect the respective economic interests of BMS and Gilead and are based on the proportions of the net selling price of Atripla attributable to efavirenz and Truvada. Since the net selling price for Truvada may change over time relative to the net selling price of efavirenz, both BMS's and our respective economic interests in the joint venture may vary annually.

We and BMS share marketing and sales efforts. Since the second quarter of 2011, except for a limited number of activities that will be jointly managed, the parties no longer coordinate detailing and promotional activities in the United States, and the parties have begun to reduce their joint promotional efforts in Canada, as we launch Complera and Stribild. The parties will continue to collaborate on activities such as manufacturing, regulatory, compliance and pharmacovigilance. We are responsible for accounting, financial reporting, tax reporting, manufacturing and product distribution for the joint venture. Both parties provide their respective bulk active pharmaceutical ingredients to the joint venture at their approximate market values. In 2006, we and BMS amended the joint venture's collaboration agreement to allow the joint venture to sell Atripla into Canada. As of September 30, 2012 and December 31, 2011, the joint venture held efavirenz active pharmaceutical ingredient which it purchased from BMS at BMS's estimated net selling price of efavirenz in the U.S. market. These amounts are included in inventories on our Condensed Consolidated Balance Sheets. As of September 30, 2012, total assets held by the joint venture were $1.85 billion and consisted primarily of cash and cash equivalents of $210.3 million, accounts receivable of $228.4 million and inventories of $1.40 billion; total liabilities were $1.46 billion and consisted primarily of accounts payable of $570.9 million and other accrued expenses of $327.2 million. As of December 31, 2011, total assets held by the joint venture were $1.62 billion and consisted primarily of cash and cash equivalents of $156.9 million, accounts receivable of $235.6 million and inventories of $1.19 billion; total liabilities were $1.27 billion and consisted primarily of accounts payable of $561.1 million and other accrued expenses of $232.9 million. These asset and liability amounts do not reflect the impact of intercompany eliminations that are included in our Condensed Consolidated Balance Sheets. Although we consolidate the joint venture, the legal structure of the joint venture limits the recourse that its creditors will have over our general credit or assets.

Europe

In 2007, Gilead Sciences Limited, a wholly-owned subsidiary in Ireland, and BMS entered into a collaboration arrangement to commercialize and distribute Atripla in the European Union, Iceland, Liechtenstein, Norway and Switzerland (collectively, the European Territory). The parties formed a limited liability company, which we consolidate, to manufacture Atripla for distribution in the European Territory using efavirenz that it purchases from BMS at BMS's estimated net selling price of efavirenz in the European Territory. We are responsible for product distribution, inventory management and warehousing. Through our local subsidiaries, we have primary responsibility for order fulfillment, collection of receivables, customer relations and handling of sales returns in all the territories where we and BMS promote Atripla. Revenue and cost sharing is based on the relative ratio of the respective net selling prices of the components of Atripla, Truvada and efavirenz.

Starting in the first quarter of 2012, except for a limited number of activities that will be jointly managed, the parties no longer coordinate detailing and promotional activities in the region. We are also responsible for accounting, financial reporting and tax reporting for the collaboration. As of September 30, 2012 and December 31, 2011, efavirenz purchased from BMS at BMS's estimated net selling price of efavirenz in the European Territory is included in inventories on our Condensed Consolidated Balance Sheets.

The parties also formed a limited liability company to hold the marketing authorization for Atripla in Europe. We have primary responsibility for regulatory activities. In the major market countries, both parties have agreed to continue to use commercially reasonable efforts to independently promote Atripla.

9.LONG-TERM OBLIGATIONS

Financing Arrangements

The following table summarizes the carrying amount of our borrowings under various financing arrangements (in thousands):

Type of Borrowing	Description	Issue Date	Due Date	Interest Rate	Carrying Value as of September 30, 2012	December 31, 2011
Convertible Senior	May 2013 Notes	April 2006	May 2013	0.625%	$630,838	$ 607,036
Convertible Senior	May 2014 Notes	July 2010	May 2014	1.00%	1,202,938	1,181,525
Convertible Senior	May 2016 Notes	July 2010	May 2016	1.625%	1,151,236	1,132,293
Senior Unsecured	April 2021 Notes	March 2011	April 2021	4.50%	992,709	992,066
Senior Unsecured	December 2014 Notes	December 2011	December 2014	2.40%	749,315	749,078
Senior Unsecured	December 2016 Notes	December 2011	December 2016	3.05%	699,037	698,864
Senior Unsecured	December 2021 Notes	December 2011	December 2021	4.40%	1,247,356	1,247,138
Senior Unsecured	December 2041 Notes	December 2011	December 2041	5.65%	997,791	997,734
Term Loan Facility	Term Loan	January 2012	January 2015	Variable	—	—
Credit Facility	Short-Term Revolver	January 2012	January 2013	Variable	350,000	—
Credit Facility	Five-Year Revolver	January 2012	January 2017	Variable	750,000	—
Total debt, net					$8,771,220	$ 7,605,734
Less current portion					1,730,838	—
Total long-term debt, net					$7,040,382	$ 7,605,734

Credit Facilities

We were eligible to borrow up to an aggregate of $1.25 billion in revolving credit loans under an amended and restated credit agreement that we entered into in 2007. The credit agreement also included a sub-facility for swing-line loans and letters of credit. As of December 31, 2011, we had $4.0 million in letters of credit outstanding under the credit agreement. In January 2012, we fully repaid the outstanding obligations under this credit agreement and terminated the credit agreement.

During the first quarter of 2012, in conjunction with our acquisition of Pharmasset, we entered into a five-year $1.25 billion revolving credit facility credit agreement (the Five-Year Revolving Credit Agreement), a $750.0 million short-term revolving credit facility credit agreement (the Short-Term Revolving Credit Agreement) and a $1.00 billion term loan facility (the Term Loan Credit Agreement). We borrowed $750.0 million under the Five-Year Revolving Credit Agreement, $400.0 million under the Short-Term Revolving Credit Agreement and $1.00 billion under the Term Loan Credit Agreement, upon the close of the acquisition. During the third quarter of 2012, we fully repaid the remaining $300.0 million of outstanding debt under the Term Loan Credit Agreement. We also repaid $50.0 million of the outstanding debt under the Short-Term Revolving Credit Agreement during the third quarter of 2012.

All three credit agreements contain customary representations, warranties, affirmative, negative and financial maintenance covenants and events of default. The loans bear interest at either (i) the Eurodollar Rate plus the Applicable Margin or (ii) the Base Rate plus the Applicable Margin, each as defined in the applicable credit agreement. We may reduce the commitments and may prepay loans under any of these agreements in whole or in part at any time without premium or penalty. We are required to comply with certain covenants under the credit agreements and notes indentures and as of September 30, 2012, we were in compliance with all such covenants.

The Five-Year Revolving Credit Agreement was inclusive of a $30.0 million swing line loan sub-facility and a $25.0 million letter of credit sub-facility. As of September 30, 2012, we had $6.9 million in letters of credit outstanding under the Five-Year Revolving Credit Agreement. The Five-Year Revolving Credit Agreement will terminate and all unpaid borrowings thereunder shall be due and payable in January 2017. The Short-Term Revolving Credit Agreement will terminate and all unpaid borrowings thereunder shall be due and payable in January 2013; however, at our request, the maturity date may be extended until January 2014.

10. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

In June 2011, we received a subpoena from the United States Attorney's Office for the Northern District of California requesting documents related to the manufacture, and related quality and distribution practices, of Atripla, Emtriva, Hepsera, Letairis, Truvada, Viread and Complera. We have been cooperating and will continue to cooperate with this governmental inquiry. An estimate of a possible loss or range of losses cannot be determined.

We are a party to various legal actions that arose in the ordinary course of our business. We do not believe that any of these legal actions will have a material adverse impact on our consolidated business, financial position or results of operations.

11. STOCK-BASED COMPENSATION EXPENSE

The following table summarizes the stock-based compensation expense included in our Condensed Consolidated Statements of Income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Cost of goods sold	$1,864	$2,234	$6,084	$7,765
Research and development expenses	23,236	18,389	162,214	54,529
Selling, general and administrative expenses	29,364	25,897	177,237	83,821
Stock-based compensation expense included in total costs and expenses	54,464	46,520	345,535	146,115
Income tax effect	(15,022)	(11,299)	(41,253)	(36,365)
Stock-based compensation expense, net of tax	$39,442	$35,221	$304,282	$109,750

Total stock-based compensation for the nine months ended September 30, 2012 included $100.1 million and $93.8 million in R&D and SG&A expenses, respectively, related to the acceleration of unvested stock options in connection with the acquisition of Pharmasset, which closed during the first quarter of 2012.

12. STOCKHOLDERS' EQUITY

Stock Repurchase Program

During the three months ended September 30, 2012, we repurchased a total of $205.2 million or 3.5 million shares of common stock under our January 2011, three-year, $5.00 billion stock repurchase program. During the nine months ended September 30, 2012, we repurchased a total of $466.9 million or 8.7 million shares of common stock under our January 2011 stock repurchase program.

13. SEGMENT INFORMATION

We operate in one business segment, which primarily focuses on the development and commercialization of human therapeutics for life threatening diseases. All products are included in one segment, because the majority of our products have similar economic and other characteristics, including the nature of the products and production processes, type of customers, distribution methods and regulatory environment.

Product sales consisted of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Antiviral products:				
Atripla	$865,378	$794,699	$2,656,997	$2,361,203
Truvada	804,190	744,727	2,348,386	2,129,139
Viread	214,909	192,887	622,016	546,999
Complera/Eviplera	99,297	19,044	224,386	19,044
Stribild	17,511	—	17,511	—
Hepsera	27,319	35,631	82,807	112,383
Emtriva	7,229	7,667	21,819	20,975
Total antiviral products	2,035,833	1,794,655	5,973,922	5,189,743
Letairis	105,054	78,954	293,976	214,765
Ranexa	95,066	81,983	273,822	236,353
AmBisome	87,448	82,241	255,865	249,372
Other products	34,577	28,026	89,975	78,792
Total product sales	$2,357,978	$2,065,859	$6,887,560	$5,969,025

The following table summarizes revenues from each of our customers who individually accounted for 10% or more of our total revenues (as a percentage of total revenues):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
Cardinal Health, Inc.	18	%	18	%	19	%	17	%
McKesson Corp.	16	%	15	%	16	%	15	%
AmerisourceBergen Corp.	11	%	13	%	11	%	13	%

14. INCOME TAXES

Our income tax rate of 29.4% and 29.9% for the three and nine months ended September 30, 2012, respectively, differed from the U.S. federal statutory rate of 35% due primarily to tax credits and certain operating earnings from non-U.S subsidiaries that are considered indefinitely invested outside of the United States, partially offset by state taxes, the stock-based compensation expense related to the Pharmasset acquisition and contingent consideration expense related to certain acquisitions for which we received no tax benefit. We do not provide for U.S. income taxes on undistributed earnings of our foreign operations that are intended to be permanently reinvested.

We file federal, state and foreign income tax returns in many jurisdictions in the United States and abroad. For federal income tax purposes, the statute of limitations is open for 2008 and onwards. For certain acquired entities, the statute of limitations is open for all years from inception due to our utilization of their net operating losses and credits carried over from prior years. For California income tax purposes, the statute of limitations is open for 2007 and onwards. Our income tax returns are audited by federal, state and foreign tax authorities. We are currently under examination by the Internal Revenue Service (IRS) for the 2008 and 2009 tax years and by various state and foreign jurisdictions. There are differing interpretations of tax laws and regulations, and as a result, significant disputes may arise with these tax authorities involving issues of the timing and amount of deductions and allocations of income among various tax jurisdictions. We periodically evaluate our exposures associated with our tax filing positions.

As of September 30, 2012, we believe that it is reasonably possible that our unrecognized tax benefits will not significantly change in the next 12 months as we do not expect to have clarification from the IRS and other tax authorities regarding any of our uncertain tax positions.

We record liabilities related to uncertain tax positions in accordance with the income tax guidance which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a minimum recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. We do not believe any of our uncertain tax positions will have a material adverse effect on our Condensed Consolidated Financial Statements, although an adverse resolution of one or more of these uncertain tax positions in any period could have a material impact on the results of operations for that period.

15. SUBSEQUENT EVENTS

In July 2012, we entered into a purchase and sale agreement to acquire an office building totaling approximately 294,000 square feet located in Foster City, California, for approximately $180.0 million in cash. We made an initial refundable deposit of $5.0 million into escrow during the third quarter of 2012. The transaction subsequently closed on November 1, 2012, at which time, the remaining balance of $175.0 million was paid into escrow.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Quarterly Report on Form 10-Q contains forward-looking statements regarding future events and our future results that are subject to the safe harbors created under the Securities Act of 1933, as amended (the Securities Act), and the Securities Exchange Act of 1934, as amended (the Exchange Act). The forward-looking statements are contained principally in this section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Risk Factors." Words such as "expect," "anticipate," "target," "goal," "project," "hope," "intend," "believe," "seek," "estimate," "continue," "may," "could," "should," "might," variations of such words and similar expressions intended to identify such forward-looking statements. In addition, any statements other than statements of historical fact are forward-looking statements, including statements regarding overall trends, operating cost and revenue trends, liquidity and capital needs and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends and similar expressions. We have based these forward-looking statements on our current expectations about future events. These statements are not guarantees of future performance and involve risks, uncertainties and assumptions that are difficult to predict. Our actual results may differ materially from those suggested by these forward-looking statements for various reasons, including those identified below under "Risk Factors." Given these risks and uncertainties, you are cautioned not to place undue reliance on forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. Except as required under federal securities laws and the rules and regulations of the Securities and Exchange Commission (SEC), we do not undertake, and specifically decline, any obligation to update any of these statements or to publicly announce the results of any revisions to any forward-looking statements after the distribution of this report, whether as a result of new information, future events, changes in assumptions or otherwise. In evaluating our business, you should carefully consider the risks described in the section entitled "Risk Factors" under Part II, Item 1A below, in addition to the other information in this Quarterly Report on Form 10-Q. Any of the risks contained herein could materially and adversely affect our business, results of operations and financial condition.

You should read the following management's discussion and analysis of our financial condition and results of operations in conjunction with our audited Consolidated Financial Statements and related notes thereto included as part of our Annual Report on Form 10-K for the year ended December 31, 2011 and our unaudited Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2012 and other disclosures (including the disclosures under "Part II. Item 1A. Risk Factors") included in this Quarterly Report on Form 10-Q. Our Condensed Consolidated Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles (GAAP) and are presented in U.S. dollars.

Management Overview

Gilead Sciences, Inc. (Gilead, we or us) is a research-based biopharmaceutical company that discovers, develops and commercializes innovative medicines in areas of unmet medical need. With each new discovery and experimental drug candidate, we seek to improve the care of patients suffering from life-threatening diseases around the world. Our primary areas of focus include human immunodeficiency virus (HIV)/AIDS, liver diseases such as hepatitis B virus (HBV) and hepatitis C virus (HCV), serious cardiovascular/metabolic and respiratory conditions and various oncologic disease areas. We continue to seek to add to our existing portfolio of products through our internal discovery and clinical development programs and through a product acquisition and in-licensing strategy.

Our product portfolio is comprised of Atripla®, Truvada®, Viread®, Emtriva®, Complera®/Eviplera®, Stribild™, Hepsera®, AmBisome®, Letairis®, Ranexa®, Cayston® and Vistide®. In addition, we also sell and distribute certain products through our corporate partners under royalty-paying collaborative agreements. For example, F. Hoffmann-La Roche Ltd (together with Hoffmann-La Roche Inc., Roche) markets Tamiflu®; GlaxoSmithKline Inc. (GSK) markets Hepsera and Viread in certain territories outside of the United States; GSK also markets Volibris® outside of the United States; Astellas Pharma US, Inc. markets AmBisome in the United States and Canada; Astellas US LLC markets Lexiscan® injection in the United States; Rapidscan Pharma Solutions, Inc. markets Rapiscan® in certain territories outside of the United States; Menarini International Operations Luxembourg SA markets Ranexa in certain territories outside of the United States; and Japan Tobacco Inc. (Japan Tobacco) markets Truvada, Viread and Emtriva in Japan.

Business Highlights

During the third quarter of 2012, our product sales increased 14% over the same quarter in 2011 and we continued to advance our product pipeline across all therapeutic areas. We believe the combination of our existing internal research programs and our recent partnerships and acquisitions will drive research and development efforts and accelerate our product pipeline so that we can continue to bring innovative therapies to individuals who are living with unmet medical needs. During the third quarter of 2012, we made the following announcements:

- The U.S. Food and Drug Administration (FDA) approved once-daily oral Truvada, in combination with safer sex practices, to reduce the risk of sexually acquired HIV-1 infection in adults at high risk for acquiring HIV. Truvada is the first drug to be approved for HIV prevention in uninfected adults, a strategy called pre-exposure prophylaxis (PrEP).
- 24-week data from a Phase 3 clinical trial, SPIRIT (Switching boosted PI to Rilpivirine In Combination with Truvada as a Single Tablet Regimen), which evaluated virologically suppressed treatment-experienced HIV patients switching from a multi-pill regimen containing a ritonavir-boosted protease inhibitor to the once-daily single tablet regimen Complera. The study met its 24-week primary endpoint, which found that switching to Complera was non-inferior to remaining on a ritonavir-boosted protease inhibitor regimen.
- Two-year Phase 3 clinical trial results showing that our integrase inhibitor, elvitegravir, dosed once daily is non-inferior to raltegravir dosed twice daily among treatment-experienced HIV patients.
- Full clinical trial results from a pivotal Phase 3 study evaluating cobicistat, a pharmacoenhancing or "boosting" agent for HIV therapy, compared to ritonavir, currently the only approved agent used to boost certain antiretroviral treatment regimens. The study found that an HIV regimen containing a cobicistat-boosted protease inhibitor was non-inferior to a regimen containing a ritonavir-boosted protease inhibitor at 48 weeks of therapy.

In August 2012, the FDA approved Stribild, a complete once-daily single tablet regimen for the treatment of HIV-1 infection in treatment-naïve adults. Stribild, referred to as “Quad” prior to FDA approval, combines four compounds in one daily tablet: elvitegravir, cobicistat, emtricitabine and tenofovir disoproxil fumarate.

Financial Highlights

During the third quarter of 2012, total revenues grew 14% to $2.43 billion compared to $2.12 billion in the third quarter of 2011. Total product sales were $2.36 billion, an increase of 14% over the same period in 2011. The growth in product sales was due primarily to our antiviral franchise, where sales increased 13% to $2.04 billion compared to the same period last year. Product gross margin increased from 74% in the third quarter of 2011 to 75% in the third quarter of 2012 due primarily to lower royalty expenses, partially offset by changes in our product mix.

Research and development (R&D) expenses were $465.8 million for the third quarter of 2012 and $290.1 million for the same period in 2011, an increase of $175.8 million, or 61%. The increase was due primarily to the continued progression of our clinical studies, particularly in liver disease and oncology.

Selling, general and administrative (SG&A) expenses were $319.6 million for the third quarter of 2012 and $295.9 million for the same period in 2011, an increase of $23.7 million, or 8%. The increase was due primarily to increased expenses to support the ongoing growth of our business and an increase in the U.S. pharmaceutical excise tax, partially offset by lower bad debt expense.

Net income for the third quarter of 2012 was $675.5 million, a 9% decrease from $741.1 million for the same period in 2011 due primarily to our continued investments in R&D and increased interest expense related to the additional debt we issued in connection with our acquisition of Pharmasset, Inc. (Pharmasset). Our diluted earnings per share decreased by 11% to $0.85 in the third quarter of 2012 from $0.95 in the same period in 2011 due primarily to the decrease in net income and an increase in diluted shares outstanding. The higher average stock price for the third quarter of 2012 compared to the same period in 2011 resulted in an increase in the number of diluted weighted average shares outstanding related to our convertible senior notes and related warrants.

Liquidity and Financing Activity

Cash, cash equivalents and marketable securities were $2.65 billion at September 30, 2012, a decrease of $7.31 billion from December 31, 2011. The primary uses of cash during the first nine months of 2012 were $11.1 billion for the acquisition of Pharmasset and $1.05 billion for the repayment of bank debt. The primary sources of cash during the first nine months of 2012 were $2.49 billion of operating cash flows and $2.14 billion in net proceeds from the issuance of bank debt in conjunction with our acquisition of Pharmasset.

In the third quarter of 2012, we repurchased a total of $205.2 million or 3.5 million shares of common stock under our January 2011, three-year, $5.00 billion stock repurchase program. As of September 30, 2012, we had repurchased $869.9 million of our common stock under this program.

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Acquisition

On January 17, 2012, we completed the acquisition of Pharmasset, a publicly-held clinical-stage pharmaceutical company committed to discovering, developing and commercializing novel drugs to treat viral infections. Pharmasset's primary focus was the development of oral therapeutics for the treatment of HCV infection. Pharmasset's lead compound, now known as GS-7977, is a nucleotide analog which, as of January 2012, was being evaluated in Phase 2 and Phase 3 clinical studies for the treatment of HCV-infection across genotypes. We believe the acquisition of Pharmasset provides us with an opportunity to complement our existing HCV portfolio and helps advance our effort to develop all-oral regimens for the treatment of HCV.

We acquired all of the outstanding shares of common stock of Pharmasset for $137 per share in cash through a tender offer and subsequent merger under the terms of an agreement and plan of merger entered into in November 2011. The aggregate cash payment to acquire all of the outstanding shares of common stock was $11.1 billion. We financed the transaction with approximately $5.2 billion in cash on hand, $3.7 billion in senior unsecured notes issued in December 2011 and $2.2 billion in bank debt issued in January 2012.

The Pharmasset acquisition was accounted for as a business combination. The results of operations of Pharmasset have been included in our Condensed Consolidated Statement of Income since January 13, 2012, the date on which we acquired approximately 88% of the outstanding shares of common stock of Pharmasset, cash consideration was transferred, and as a result, we obtained effective control of Pharmasset. The acquisition was completed on January 17, 2012, at which time Pharmasset became a wholly-owned subsidiary of Gilead and was integrated into our operations. As we do not track earnings results by product candidate or therapeutic area, we do not maintain separate earnings results for the acquired Pharmasset business.

The following table summarizes the components of the cash paid to acquire Pharmasset (in thousands):

Total consideration transferred	$10,858,372
Stock-based compensation expense	193,937
Total cash paid	$11,052,309

The $11.1 billion cash payment consisted of a $10.38 billion cash payment to the outstanding common stockholders as well as a $668.3 million cash payment to option holders under the Pharmasset stock option plans. The $10.38 billion cash payment to the outstanding common stockholders and $474.3 million of the cash payment to the option holders under the Pharmasset stock option plans were accounted for as consideration transferred. The remaining $193.9 million of cash payment was accounted for as stock-based compensation expense resulting from the accelerated vesting of Pharmasset employee options immediately prior to the acquisition.

The following table summarizes the acquisition date fair values of assets acquired and liabilities assumed, and the consideration transferred (in thousands):

Intangible assets - in-process research and development	$10,720,000
Cash and cash equivalents	106,737
Other assets acquired (liabilities assumed), net	(43,182)
Total identifiable net assets	10,783,555
Goodwill	74,817
Total consideration transferred	$10,858,372

In-Process Research and Development (IPR&D)

The estimated fair value of the acquired IPR&D related to GS-7977 was $10.72 billion, which was determined using a probability-weighted income approach, that discounts expected future cash flows to present value. The estimated net cash flows were discounted using a discount rate of 12%, which is based on the estimated weighted-average cost of capital for companies with profiles similar to that of Pharmasset. This rate is comparable to the estimated internal rate of return for the acquisition and represents the rate that market participants would use to value the intangible asset. The projected cash flows from GS-7977 were based on key assumptions such as: the time and resources needed to complete its development considering its stage of development on the acquisition date, the probability of obtaining approval from the FDA and other regulatory agencies, estimates of revenues and operating profits, the life of the potential commercialized product and other associated risks related to the viability of and potential alternative treatments in future target markets. Intangible assets related to IPR&D projects are considered to be indefinite-lived assets until the completion or abandonment of the associated R&D efforts.

Goodwill

The $74.8 million of goodwill represents the excess of the consideration transferred over the fair values of assets acquired and liabilities assumed and is attributable to the synergies expected from combining our R&D operations with Pharmasset's. None of the goodwill is expected to be deductible for income tax purposes.

Stock-Based Compensation Expense

The stock-based compensation expense recognized for the accelerated vesting of employee options immediately prior to the acquisition was reported in our Condensed Consolidated Statement of Income as follows (in thousands):

Research and development expense	$100,149
Selling, general and administrative expense	93,788
Total stock-based compensation expense	$193,937

Other Costs

Other costs incurred in connection with the acquisition include (in thousands):

	Nine Months Ended September 30, 2012	Three Months Ended December 31, 2011
Transaction costs (e.g. investment advisory, legal and accounting fees)	$10,463	$28,461
Bridge financing costs	7,333	23,817
Restructuring costs	14,929	—
Total other costs	$32,725	$52,278

The following table summarizes these costs by the line item in the Condensed Consolidated Statement of Income in which these costs were recognized (in thousands):

	Nine Months Ended September 30, 2012	Three Months Ended December 31, 2011
Research and development expense	$7,710	$—
Selling, general and administrative expense	17,682	28,461
Interest expense	7,333	23,817
Total other costs	$32,725	$52,278

Pro Forma Information

The following unaudited pro forma information presents the combined results of operations of Gilead and Pharmasset as if the acquisition of Pharmasset had been completed on January 1, 2011, with adjustments to give effect to pro forma events that are directly attributable to the acquisition. The unaudited pro forma results do not reflect any operating efficiencies or potential cost savings which may result from the consolidation of the operations of Gilead and Pharmasset. Accordingly, these unaudited pro forma results are presented for informational purposes only and are not necessarily indicative of what the actual results of operations of the combined company would have been if the acquisition had occurred at the beginning of the period presented, nor are they indicative of future results of operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Total revenues	$2,426,597	$2,121,660	$7,114,232	$6,185,007
Net income attributable to Gilead	$680,483	$677,662	$1,983,004	$1,756,056

The unaudited pro forma consolidated results include non-recurring pro forma adjustments that assume the acquisition occurred on January 1, 2011. Stock-based compensation expenses of $193.9 million incurred during the nine months ended September 30, 2012 were included in the net income attributable to Gilead for the nine months ended September 30, 2011. Other costs of $17.8 million incurred during the nine months ended September 30, 2012 were included in the net income attributable to Gilead for the nine months ended September 30, 2011. Of the $17.8 million, $0.3 million was incurred during the three months ended September 30, 2012. Other costs of $52.3 million incurred during the three months ended December 31, 2011 were included in net income attributable to Gilead for the nine months ended September 30, 2011.

Critical Accounting Policies, Estimates and Judgments

We have updated our critical accounting policies, estimates and judgments to include the valuation of contingent consideration resulting from a business combination. There have been no other material changes in our critical accounting policies, estimates and judgments during the nine months ended September 30, 2012 compared to the disclosures in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2011.

Valuation of Contingent Consideration Resulting from a Business Combination

In connection with certain acquisitions, we may be required to pay future consideration that is contingent upon the achievement of specified development, regulatory approval or sales-based milestone events. We record contingent consideration resulting from a business combination at its fair value on the acquisition date. Each quarter thereafter, we revalue these obligations and record increases or decreases in their fair value in R&D expense within our Condensed Consolidated Statement of Income until such time that the related product candidate reaches commercialization.

Increases or decreases in the fair value of the contingent consideration liabilities can result from updates to assumptions such as the expected timing or probability of achieving the specified milestones, changes in projected revenues or changes in discount rates. Significant judgment is employed in determining these assumptions as of the acquisition date and for each subsequent period. Updates to assumptions could have a significant impact on our results of operations in any given period. Actual results may differ from estimates.

Results of Operations

Total Revenues

Total revenues included product sales, royalty revenues and contract and other revenues. Total revenues for the three months ended September 30, 2012 were $2.43 billion, up 14% compared to $2.12 billion for the same period in 2011. For the nine months ended September 30, 2012, total revenues were $7.11 billion, up 15% compared to $6.19 billion for the same period in 2011. Increases in total revenues were driven by growth in product sales. A significant percentage of our product sales is denominated in foreign currencies and we face exposure to adverse movements in foreign currency exchange rates. We use foreign currency exchange forward and option contracts to hedge a percentage of our forecasted international sales, primarily those denominated in Euro. Foreign currency exchange, net of hedges, had an unfavorable impact of $20.5 million on our third quarter 2012 product sales and an unfavorable impact of $69.1 million on our product sales for the nine months ended September 30, 2012 compared to the same periods in 2011.

Product Sales

Total product sales were $2.36 billion for the three months ended September 30, 2012, an increase of 14% over total product sales of $2.07 billion for the same period in 2011. For the nine months ended September 30, 2012, total product sales were $6.89 billion, an increase of 15% over total product sales of $5.97 billion for the same period in 2011. Increases in product sales were driven primarily by our antiviral franchise, resulting from increased sales of Atripla, Truvada and Complera/Eviplera. Following the FDA's approval on August 27, 2012, we launched Stribild in the United States which contributed $17.5 million to total product sales for the third quarter of 2012.

Product sales in the United States increased by 20% and 22% for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, primarily driven by strong retail demand and continued sales growth in our antiviral franchise.

Letairis sales contributed $105.1 million and $294.0 million to our three and nine months ended September 30, 2012 product sales, respectively, an increase of 33% and 37% compared to the same periods in 2011. Ranexa sales contributed $95.1 million and $273.8 million to our three and nine months ended September 30, 2012 product sales, respectively, an increase of 16% for both periods compared to the respective periods in 2011.

Product sales in Europe increased by 5% for both the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, primarily driven by sales growth in our antiviral franchise. Foreign currency exchange, net of hedges, had an unfavorable impact of $22.3 million and $76.9 million on our European product sales in the three and nine months ended September 30, 2012, respectively, compared to the same periods last year.

The following table summarizes the period over period changes in our sales by product (in thousands):

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
Antiviral products:						
Atripla	$865,378	$794,699	9 %	$2,656,997	$2,361,203	13 %
Truvada	804,190	744,727	8 %	2,348,386	2,129,139	10 %
Viread	214,909	192,887	11 %	622,016	546,999	14 %
Complera/Eviplera	99,297	19,044	421%	224,386	19,044	1,078%
Stribild	17,511	—	—	17,511	—	—
Hepsera	27,319	35,631	(23)%	82,807	112,383	(26)%
Emtriva	7,229	7,667	(6)%	21,819	20,975	4 %
Total antiviral products	2,035,833	1,794,655	13 %	5,973,922	5,189,743	15 %
Letairis	105,054	78,954	33 %	293,976	214,765	37 %
Ranexa	95,066	81,983	16 %	273,822	236,353	16 %
AmBisome	87,448	82,241	6 %	255,865	249,372	3 %
Other	34,577	28,026	23 %	89,975	78,792	14 %
Total product sales	$2,357,978	$2,065,859	14 %	$6,887,560	$5,969,025	15 %

Antiviral Products

Antiviral product sales increased by 13% and 15% for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011.

- Atripla

Atripla sales increased by 9% and 13% for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, driven primarily by sales growth in the United States, Europe and Latin America. Atripla sales include the efavirenz component which has a gross margin of zero. The efavirenz portion of our Atripla sales was $316.9 million and $976.8 million for the three and nine months ended September 30, 2012, compared to $290.8 million and $863.0 million for the three and nine months ended September 30, 2011, respectively. Atripla sales accounted for 43% and 44% of our total antiviral product sales for the three and nine months ended September 30, 2012, respectively.

- Truvada

Truvada sales increased by 8% and 10% for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, driven primarily by sales growth in the United States. Truvada sales accounted for 40% and 39% of our total antiviral product sales for the three and nine months ended September 30, 2012, respectively.

- Complera/Eviplera

Sales of Complera/Eviplera increased to $99.3 million and $224.4 million for the three and nine months ended September 30, 2012, respectively, compared to $19.0 million for both the three and nine months ended September 30, 2011, primarily due to sales growth in the United States. Complera was approved in the United States in August 2011, and Eviplera was approved in the European Union in November 2011.

- Stribild

Sales of Stribild were $17.5 million for the three months ended September 30, 2012. Stribild was approved in the United States in August 2012.

Other Product Sales

Other product sales consist primarily of Letairis, Ranexa and AmBisome. During the three and nine months ended September 30, 2012, sales of Letairis increased by 33% and 37%, respectively, sales of Ranexa increased by 16% for both periods and sales of AmBisome increased by 6% and 3%, respectively. These increases were primarily due to sales growth. AmBisome product sales in the United States and Canada related solely to our sales of AmBisome to Astellas Pharma US, Inc., which were recorded at our manufacturing cost.

Royalty Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
(In thousands, except percentages)	2012	2011	Change	2012	2011	Change
Royalty revenues	$63,915	$51,629	24 %	$216,126	$204,615	6 %

Royalty revenues increased 24% and 6% for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, primarily due to increased royalty revenues from GlaxoSmithKline Inc. for Volibris and Japan Tobacco for Truvada.

Cost of Goods Sold and Product Gross Margin

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands, except percentages)	2012	2011	2012	2011
Total product sales	$2,357,978	$2,065,859	$6,887,560	$5,969,025
Cost of goods sold	$597,269	$531,989	$1,795,545	$1,539,963
Product gross margin	75 %	74 %	74 %	74 %

Our product gross margin was 75% for the three months ended September 30, 2012, an increase of 1% compared to the same period in 2011, primarily due to lower royalty expenses, partially offset by changes in our product mix. Product gross margin was 74% for the nine months ended September 30, 2012 and 2011.

Research and Development Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
(In thousands, except percentages)	2012	2011	Change	2012	2011	Change
Research and development	$465,831	$290,066	61 %	$1,320,286	$826,915	60 %

We manage our R&D expenses by identifying the R&D activities we anticipate will be performed during a given period and then prioritizing efforts based on scientific data, probability of successful development, market potential, available human and capital resources and other similar considerations. We continually review our R&D pipeline and the status of development and, as necessary, reallocate resources among the R&D portfolio that we believe will best support the future growth of our business.

R&D expenses summarized above consist primarily of personnel costs, including salaries, benefits and stock-based compensation, clinical studies performed by contract research organizations, materials and supplies, licenses and fees, milestone payments under collaboration arrangements and overhead allocations consisting of various support and facilities-related costs.

R&D expenses for the three months ended September 30, 2012 increased by $175.8 million, or 61%, compared to the same period in 2011, due primarily to a $86.8 million increase in clinical studies and outside services mainly related to study progression in liver disease and oncology and a $58.8 million increase in the estimated fair value of our contingent consideration liabilities resulting from updates to the assumptions used when estimating the fair value of these obligations due primarily to the advancement in the development of acquired compounds.

R&D expenses for the nine months ended September 30, 2012 increased by $493.4 million, or 60%, compared to the same period in 2011, due primarily to a $219.5 million increase in clinical studies and outside services mainly related to study progression in liver disease and oncology; a $100.1 million stock-based compensation expense resulting from the Pharmasset acquisition in the first quarter of 2012; a $93.6 million increase in personnel expenses due to higher headcount and expenses to support the growth of our business; and a $64.1 million increase in the estimated fair value of our contingent consideration liabilities resulting from updates to the assumptions used when estimating the fair value of these obligations due primarily to the advancement in the development of acquired compounds.

Selling, General and Administrative Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
(In thousands, except percentages)	2012	2011	Change	2012	2011	Change
Selling, general and administrative	$319,583	$295,927	8 %	$1,095,209	$895,764	22 %

SG&A expenses relate to sales and marketing, finance, human resources, legal and other administrative activities. Expenses are primarily comprised of facilities and overhead costs; marketing, advertising and legal expenses; and other general and administrative costs.

SG&A expenses for the three months ended September 30, 2012 increased by $23.7 million or 8%, compared to the same period in 2011, due primarily to $18.9 million in increased headcount related and other expenses to support the growth of our business and an $8.3 million increase in the pharmaceutical excise tax, partially offset by a reduction in bad debt expense of $11.1 million.

SG&A expenses for the nine months ended September 30, 2012 increased by $199.4 million or 22%, compared to the same period in 2011, due primarily to stock-based compensation expense of $93.8 million resulting from the Pharmasset acquisition; a $57.3 million increase in headcount related expenses to support the ongoing growth of our business; a $32.5 million increase in the pharmaceutical excise tax; and a $7.2 million increase in acquisition-related transaction costs. These increases were partially offset by a net reduction in bad debt expense of $23.4 million, which included a gain of $29.9 million related to the sale of our accounts receivable balances in Spain in the second quarter of 2012.

Interest Expense

Interest expense for the three and nine months ended September 30, 2012 was $89.3 million and $275.0 million, respectively, and increased by $46.2 million and $144.6 million compared to the same periods in 2011, respectively. The increase for both the three and nine months ended September 30, 2012 was due primarily to the additional debt we issued in connection with our acquisition of Pharmasset, which included $3.70 billion in senior unsecured notes issued in December 2011 and $2.15 billion in bank debt issued in January 2012. This increase was partially offset by a decrease of $12.8 million in interest expense for the nine months ended September 30, 2012 related to the maturity of our convertible senior notes due in May 2011 (May 2011 Notes).

Other Income (Expense), Net

Other income (expense), net, for the three and nine months ended September 30, 2012 was a net expense of $3.5 million and $38.7 million, compared to net income of $14.4 million and $40.2 million for the three and nine months ended September 30, 2011. The change for the three and nine months ended September 30, 2012 was due primarily to a decrease in interest income of $12.4 million and $39.8 million, respectively, resulting from a lower cash balance after we funded the Pharmasset acquisition and a lower average yield during the period. For the nine months ended September 30, 2012, the change in other income (expense), net, also included a $40.1 million loss on Greek bonds related to Greece's restructuring of its sovereign debt in the first quarter of 2012.

Provision for Income Taxes

Our provision for income taxes was $280.1 million and $774.9 million for the three and nine months ended September 30, 2012, respectively, compared to $237.4 million and $704.9 million for the same periods in 2011, respectively. Our effective tax rate was 29.4% and 29.9% for the three and nine months ended September 30, 2012, respectively, compared to our effective tax rate of 24.4% and 24.9% for the same periods in 2011, respectively. The effective tax rates for the three and nine months ended September 30, 2012 were higher than the effective tax rates for the same periods in 2011 as a result of the expiration of the federal research tax credit as of December 31, 2011, lower earnings from non-U.S. subsidiaries that are considered indefinitely invested outside the United States as a percentage of total earnings, the stock-based compensation expense related to the Pharmasset acquisition and contingent consideration expense related to certain acquisitions for which we receive no tax benefit.

The effective tax rates for the three and nine months ended September 30, 2012 differed from the U.S. federal statutory rate of 35% due primarily to tax credits and certain operating earnings from non-U.S. subsidiaries that are considered indefinitely invested outside the United States, partially offset by state taxes, the stock-based compensation expense related to the Pharmasset acquisition and contingent consideration expense related to certain acquisitions for which we receive no tax benefit. We do not provide for U.S. income taxes on undistributed earnings of our foreign operations that are intended to be permanently reinvested.

Liquidity and Capital Resources

We believe that our existing capital resources, supplemented by our cash flows generated from operating activities, will be adequate to satisfy our capital needs for the foreseeable future. Our cash, cash equivalents and marketable securities decreased significantly in the first quarter of 2012 as we completed our acquisition of Pharmasset in January 2012. The following table summarizes our cash, cash equivalents and marketable securities, our working capital and our cash flow activities as of the end of, and for each of, the periods presented (in thousands):

	September 30, 2012	December 31, 2011
Cash, cash equivalents and marketable securities	$2,651,088	$9,963,972
Working capital	$1,078,231	$11,403,995

	Nine Months Ended September 30, 2012	2011
Cash provided by (used in):		
Operating activities	$2,488,988	$2,660,903
Investing activities	$(11,896,124)	$(850,491)
Financing activities	$1,073,197	$(1,763,051)

Cash, Cash Equivalents and Marketable Securities

Cash, cash equivalents and marketable securities totaled $2.65 billion at September 30, 2012, a decrease of $7.31 billion or 73% from $9.96 billion as of December 31, 2011 due primarily to our acquisition of Pharmasset for $11.1 billion in January 2012. Also in January 2012, we raised an additional $2.15 billion from the issuance of bank debt, of which, we repaid $1.05 billion during the nine months ended September 30, 2012. The decrease in cash, cash equivalents and marketable securities was partially offset by $2.49 billion in cash flows from operations during the nine months ended September 30, 2012.

Of the total cash, cash equivalents and marketable securities at September 30, 2012, approximately $1.91 billion was generated from operations in foreign jurisdictions and is intended for use in our foreign operations. We do not rely on unrepatriated earnings as a source of funds for our domestic business as we expect to have sufficient cash flow and borrowing capacity in the United States to fund our domestic operational and strategic needs.

Working Capital

Working capital was $1.08 billion at September 30, 2012. The decrease of $10.33 billion from December 31, 2011 was primarily attributable to a decrease of $11.1 billion in cash used in the Pharmasset acquisition and an increase in short-term debt of $1.73 billion related to the current portion of the bank debt issued to finance the Pharmasset acquisition and the current portion of our convertible senior notes due May 2013.

Cash Provided by Operating Activities

Cash provided by operating activities of $2.49 billion for the nine months ended September 30, 2012 primarily related to net income of $1.81 billion, adjusted for non-cash items such as $302.4 million of net cash inflow related to changes in operating assets and liabilities, $204.6 million of depreciation and amortization expenses and $151.6 million of non-cash stock-based compensation expenses. Cash provided by operations included the impact of $349.7 million in proceeds from the sale of accounts receivable balances in Spain in June 2012 and $193.9 million stock-based compensation expense related to the Pharmasset acquisition.

Cash provided by operating activities of $2.66 billion for the nine months ended September 30, 2011 primarily related to net income of $2.13 billion, adjusted for non-cash items such as $228.8 million of depreciation and amortization expenses, $145.8 million of non-cash stock-based compensation expenses, $43.4 million of deferred income taxes and $72.1 million of net cash inflow related to changes in operating assets and liabilities, partially offset by $30.3 million of excess tax benefits from stock option exercises.

Cash Used in Investing Activities

Cash used in investing activities for the nine months ended September 30, 2012 was $11.90 billion, consisting primarily of $10.75 billion used in our acquisition of Pharmasset, net of the stock-based compensation expense and cash acquired, and a use of $992.3 million in net purchases of marketable securities.

Cash used in investing activities for the nine months ended September 30, 2011 was $850.5 million, consisting of $588.6 million used in our acquisitions of Arresto Biosciences, Inc. and Calistoga Pharmaceuticals, Inc., a net use of $156.1 million in purchases of marketable securities and $105.8 million of capital expenditures.

Cash Provided by (Used in) Financing Activities

Cash provided by financing activities for the nine months ended September 30, 2012 was $1.07 billion, driven primarily by net proceeds of $2.14 billion from the issuance of bank debt in conjunction with the Pharmasset acquisition and proceeds of $350.3 million from issuances of common stock under our employee stock plans. The cash proceeds were partially offset by the $1.05 billion used to repay bank debt during the period and $467.0 million used to repurchase common stock under our stock repurchase program, including commissions.

Cash used in financing activities for the nine months ended September 30, 2011 was $1.76 billion, driven primarily by the $2.16 billion used to repurchase our common stock under our stock repurchase program, including commissions, and $650.0 million used to repay our May 2011 Notes, partially offset by the $987.4 million of net proceeds from the issuance of our senior unsecured notes due in April 2021.

As of September 30, 2012, the remaining authorized amount of stock repurchases that may be made under our January 2011, three-year, $5.00 billion stock repurchase program was $4.13 billion.

Subsequent Event

In July 2012, we entered into a purchase and sale agreement to acquire an office building totaling approximately 294,000 square feet located in Foster City, California, for approximately $180.0 million in cash. We made an initial refundable deposit of $5.0 million into escrow during the third quarter of 2012. The transaction subsequently closed on November 1, 2012, at which time, the remaining balance of $175.0 million was paid into escrow.

Long-Term Debt

The following table summarizes the carrying amount of our borrowings under various financing arrangements (in thousands):

Type of Borrowing	Description	Issue Date	Due Date	Interest Rate	Carrying Value as of September 30, 2012	Carrying Value as of December 31, 2011
Convertible Senior	May 2013 Notes	April 2006	May 2013	0.625%	$630,838	$ 607,036
Convertible Senior	May 2014 Notes	July 2010	May 2014	1.00%	1,202,938	1,181,525
Convertible Senior	May 2016 Notes	July 2010	May 2016	1.625%	1,151,236	1,132,293
Senior Unsecured	April 2021 Notes	March 2011	April 2021	4.50%	992,709	992,066
Senior Unsecured	December 2014 Notes	December 2011	December 2014	2.40%	749,315	749,078
Senior Unsecured	December 2016 Notes	December 2011	December 2016	3.05%	699,037	698,864
Senior Unsecured	December 2021 Notes	December 2011	December 2021	4.40%	1,247,356	1,247,138
Senior Unsecured	December 2041 Notes	December 2011	December 2041	5.65%	997,791	997,734
Term Loan Facility	Term Loan	January 2012	January 2015	Variable	—	—
Credit Facility	Short-Term Revolver	January 2012	January 2013	Variable	350,000	—
Credit Facility	Five-Year Revolver	January 2012	January 2017	Variable	750,000	—
Total debt, net					$8,771,220	$ 7,605,734
Less current portion					1,730,838	—
Total long-term debt, net					$7,040,382	$ 7,605,734

We were eligible to borrow up to an aggregate of $1.25 billion in revolving credit loans under an amended and restated credit agreement that we entered into in 2007. The credit agreement also included a sub-facility for swing-line loans and letters of credit. As of December 31, 2011, we had $4.0 million in letters of credit outstanding under the credit agreement. In January 2012, we fully repaid the outstanding obligations under this credit agreement and terminated the credit agreement.

During the first quarter of 2012, in conjunction with our acquisition of Pharmasset, we entered into a five-year $1.25 billion revolving credit facility credit agreement (the Five-Year Revolving Credit Agreement), a $750.0 million short-term revolving credit facility credit agreement (the Short-Term Revolving Credit Agreement) and a $1.00 billion term loan facility (the Term Loan Credit Agreement). We borrowed $750.0 million under the Five-Year Revolving Credit Agreement, $400.0 million under the Short-Term Revolving Credit Agreement and $1.00 billion under the Term Loan Credit Agreement, upon the close of the acquisition. In September 2012, we fully repaid the remaining $300.0 million of outstanding debt under the Term Loan Credit Agreement. We also repaid $50.0 million of the outstanding debt under the Short-Term Revolving Credit Agreement during the third quarter of 2012.

All three credit agreements contain customary representations, warranties, affirmative, negative and financial maintenance covenants and events of default. The loans bear interest at either (i) the Eurodollar Rate plus the Applicable Margin or (ii) the Base Rate plus the Applicable Margin, each as defined in the applicable credit agreement. We may reduce the commitments and may prepay loans under any of these agreements in whole or in part at any time without premium or penalty. We are required to comply with certain covenants under the credit agreements and notes indentures as of September 30, 2012, we were in compliance with all such covenants.

The Five-Year Revolving Credit Agreement was inclusive of a $30.0 million swing line loan sub-facility and a $25.0 million letter of credit sub-facility. As of September 30, 2012, we had $6.9 million in letters of credit outstanding under the Five-Year Revolving Credit Agreement. The Five-Year Revolving Credit Agreement will terminate and all unpaid borrowings thereunder shall be due and payable in January 2017. The Short-Term Revolving Credit Agreement will terminate and all unpaid borrowings thereunder shall be due and payable in January 2013; however, at our request, the maturity date may be extended until January 2014.

Off Balance Sheet Arrangements

We do not have any off balance sheet arrangements.

Recent Accounting Pronouncements

In July 2012, the Financial Accounting Standards Board (FASB) issued new accounting guidance intended to simplify the testing of indefinite-lived intangible assets for impairment. Entities will be allowed the option to first perform a qualitative assessment on impairment for indefinite-lived intangible assets to determine whether a quantitative assessment is necessary. This guidance is effective for impairment tests performed in the interim and annual periods for fiscal years beginning after September 15, 2012. Early adoption is permitted. The adoption of this guidance is not expected to have a material impact on our Consolidated Financial Statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes in our market risk during the nine months ended September 30, 2012 compared to the disclosures in Part II, Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2011.

During the first quarter of 2012, we entered into credit agreements in connection with our acquisition of Pharmasset, that are subject to variable interest rates that create an exposure to interest rate risk similar to that disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

Also during the first quarter of 2012, the Greek government restructured its sovereign debt which impacted all holders of Greek bonds. As a result, we recorded a $40.1 million loss related to the debt restructuring as part of other income (expense), net on our Condensed Consolidated Statement of Income and exchanged the Greek government-issued bonds for new securities, which we liquidated during the first quarter of 2012.

During the second quarter of 2012, we received payment on $460.6 million in past due accounts receivable from customers based in Spain. Included in this amount were proceeds from a one-time factoring arrangement, where we sold Spanish receivables with a carrying value of $319.8 million, net of the allowance for doubtful accounts. We received proceeds of $349.7 million and recorded a gain of $29.9 million, resulting primarily from the reversal of the related allowance for doubtful accounts. This gain was recorded as an offset to selling, general and administrative (SG&A) expenses in our Condensed Consolidated Statement of Income. Subsequent to this transaction, we have had no continuing involvement with the transferred receivables, which were derecognized at the time of the sale.

As of September 30, 2012, our accounts receivable in Southern Europe, specifically Greece, Italy, Portugal and Spain, totaled approximately $826.8 million, of which $314.9 million were greater than 120 days past due and $84.8 million were greater than 365 days past due. To date, we have not experienced significant losses with respect to the collection of our accounts receivable. We believe that our allowance for doubtful accounts was adequate at September 30, 2012. Within Greece and Italy, the number of days our receivables are outstanding has continued to increase. To date, we have not experienced significant losses with respect to the collection of our accounts receivable. However, we will continue to monitor the European economic environment for any collectability issues related to our outstanding receivables.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation as of September 30, 2012 was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our “disclosure controls and procedures,” which are defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as controls and other procedures of a company that are designed to ensure that the information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to the company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective at September 30, 2012.

Changes in Internal Control over Financial Reporting

Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2012, and has concluded that there was no change during such quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Limitations on the Effectiveness of Controls

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, if any, within a company have been detected. Accordingly, our disclosure controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our disclosure control system are met and, as set forth above, our Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this report, that our disclosure controls and procedures were effective to provide reasonable assurance that the objectives of our disclosure control system were met.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Litigation with Generic Manufacturers

In November 2008, we received notice that Teva Pharmaceuticals (Teva) submitted an abbreviated new drug application (ANDA) to the U.S. Food and Drug Administration (FDA) requesting permission to manufacture and market a generic version of Truvada. In the notice, Teva alleges that two of the patents associated with emtricitabine, owned by Emory University and licensed exclusively to us, are invalid, unenforceable and/or will not be infringed by Teva's manufacture, use or sale of a generic fixed-dose combination of emtricitabine and tenofovir disoproxil fumarate. In December 2008, we filed a lawsuit in U.S. District Court in New York against Teva for infringement of the two emtricitabine patents. In March 2009, we received notice that Teva submitted an ANDA to the FDA requesting permission to manufacture and market a generic fixed-dose combination of emtricitabine, tenofovir disoproxil fumarate and efavirenz. In the notice, Teva challenged the same two emtricitabine patents. In May 2009, we filed another lawsuit in U.S. District Court in New York against Teva for infringement of the two emtricitabine patents, and this lawsuit was consolidated with the lawsuit filed in December 2008. In January 2010, we received notice that Teva submitted an ANDA to the FDA requesting permission to manufacture and market a generic version of Viread. In the notice, Teva challenged four of the tenofovir disoproxil fumarate patents protecting Viread. In January 2010, we also received notices from Teva amending its ANDAs related to generic versions of our Atripla and Truvada products. In the notice related to Teva's ANDA for a generic version of Atripla, Teva challenged four patents related to tenofovir disoproxil fumarate, two additional patents related to emtricitabine and two patents related to efavirenz. In the notice related to Teva's ANDA for a generic version of Truvada, Teva challenged four patents related to tenofovir disoproxil fumarate and two additional patents related to emtricitabine. In March 2010, we filed lawsuits against Teva for infringement of the four Viread patents and two additional emtricitabine patents. In March 2010, Bristol-Myers Squibb Company and Merck & Co., Inc. filed a lawsuit against Teva for infringement of the patents related to efavirenz. Because we filed our lawsuits within the requisite 45 day period provided in the Hatch Waxman Act, there were stays preventing FDA approval of Teva's ANDAs for 30 months or until a district court decision adverse to the patents. The 30-month stay for all three Teva ANDAs expired in July 2012. However, as a result of the court's scheduling orders, Teva is prohibited from launching at risk upon expiration of that 30-month stay. The court scheduled trial to begin in February 2013 for four patents that protect tenofovir disoproxil fumarate in our Viread, Truvada and Atripla products. A trial date has not yet been set for the emtricitabine patents but we anticipate that trial will occur in the third quarter of 2013.

In June 2010, we received notice that Lupin Limited (Lupin) submitted an ANDA to the FDA requesting permission to manufacture and market a generic version of sustained release ranolazine. In the notice, Lupin alleges that ten of the patents associated with Ranexa are invalid, unenforceable and/or will not be infringed by Lupin's manufacture, use or sale of a generic version of Ranexa. In July 2010, we filed a lawsuit against Lupin in U.S. District Court in New Jersey for infringement of our patents for Ranexa. The FDA cannot approve Lupin's ANDA until we receive a district court decision or upon the expiration of the court's automatic stay in July 2013. The court has scheduled the trial for April 2013.

In August 2010, we received notice that Sigmapharm Labs (Sigmapharm) submitted an ANDA to the FDA requesting permission to manufacture and market a generic adefovir dipivoxil. In the notice, Sigmapharm alleges that both of the patents associated with Hepsera are invalid, unenforceable and/or will not be infringed by Sigmapharm's manufacture, use or sale of a generic version of Hepsera. In September 2010, we filed a lawsuit against Sigmapharm in U.S. District Court in New Jersey for infringement of our patents. The FDA cannot approve Sigmapharm's ANDA until we receive a district court decision or upon the expiration of the court's automatic stay in February 2013. The court has not yet set a trial date in this case but we anticipate that trial will occur in the first half of 2013. Upon expiry of the 30-month stay in February 2013, if Sigmapharm obtains final FDA approval of its product from the FDA, it may elect to launch its generic product "at risk" of infringing our patents prior to the decision of the court.

One of the patents challenged by Sigmapharm has also been challenged by Ranbaxy, Inc. (Ranbaxy) pursuant to a notice received in October 2010. The patent challenged by Ranbaxy expires in July 2018. We have the option of filing a lawsuit at any time if we believe that Ranbaxy is infringing our patent.

In February 2011, we received notice that Natco Pharma Ltd. (Natco) submitted an ANDA to the FDA requesting permission to manufacture and market a generic oseltamivir phosphate. In the notice, Natco alleges that one of the patents associated with Tamiflu is invalid, unenforceable and/or will not be infringed by Natco's manufacture, use or sale of a generic version of Tamiflu. In March 2011, we and F. Hoffmann-La Roche Ltd. filed a lawsuit against Natco in U.S. District Court in New Jersey for infringement of one of the patents associated with Tamiflu.

In November 2011, we received notice that Teva submitted an Abbreviated New Drug Submission (ANDS) to the Canadian Ministry of Health requesting permission to manufacture and market a generic fixed-dose combination of emtricitabine and tenofovir disoproxil fumarate. In the notice, Teva alleges that three of the patents associated with Truvada are invalid, unenforceable and/or will not be infringed by Teva's manufacture, use or sale of a generic version of Truvada. In January 2012, we filed a lawsuit against Teva in Canadian Federal Court seeking an order of prohibition against approval of this ANDS.

In December 2011, we received notice that Teva submitted an ANDS to the Canadian Ministry of Health requesting permission to manufacture and market a generic fixed-dose combination of emtricitabine, tenofovir disoproxil fumarate and efavirenz. In the notice, Teva alleges that three of our patents associated with the efavirenz component of Atripla and two of Merck's patents associated with Atripla are invalid, unenforceable and/or will not be infringed by Teva's manufacture, use or sale of a generic fixed-dose combination of emtricitabine, tenofovir disoproxil fumarate and efavirenz.

In February 2012, we filed a lawsuit against Teva in Canadian Federal Court seeking an order of prohibition against approval of this ANDS.

In July 2012, we received notice that Lupin submitted an ANDA to the FDA requesting permission to manufacture and market a generic version of Truvada. In the notice, Lupin alleges that four patents associated with emtricitabine and four patents associated with tenofovir disoproxil fumarate are invalid, unenforceable and/or will not be infringed by Lupin's manufacture, use or sale of a generic version of a fixed dose combination of emtricitabine and tenofovir disoproxil fumarate. In August 2012, we filed a lawsuit against Lupin in U.S. District Court in New York for infringement of our patents.

In July 2012, we received notice that Cipla Ltd. submitted an ANDA to the FDA requesting permission to manufacture and market a generic version of Emtriva. In the notice, Cipla alleges that two patents associated with emtricitabine are invalid, unenforceable and/or will not be infringed by Cipla's manufacture, use or sale of a generic version of emtricitabine. We are currently reviewing the notice letter. In August 2012, we filed a lawsuit against Cipla in U.S. District Court in New York for infringement of our patents.

In August 2012, we received notice that Teva submitted an ANDS to the Canadian Ministry of Health requesting permission to manufacture and market a generic version of tenofovir disoproxil fumarate. In the notice, Teva alleges that two patents associated with Viread are invalid, unenforceable and/or will not be infringed by Teva's manufacture, use or sale of a generic version of Viread. In September 2012, we filed a lawsuit against Teva in Canadian Federal Court seeking an order of prohibition against approval of this ANDS.

In October 2012, we received notice that Lupin submitted an ANDA to the FDA requesting permission to manufacture and market a generic version of Viread. In the notice, Lupin alleges that four patents associated tenofovir disoproxil fumarate are invalid, unenforceable and/or will not be infringed by Lupin's manufacture, use or sale of a generic version of tenofovir disoproxil fumarate. In October 2012, we filed a lawsuit against Lupin in U.S. District Court in New York for infringement of our patents.

We cannot predict the ultimate outcome of these actions, and we may spend significant resources enforcing and defending these patents. If we are unsuccessful in these lawsuits, some or all of our original claims in the patents may be narrowed or invalidated and the patent protection for Atripla, Truvada, Viread, Hepsera, Ranexa and Tamiflu in the United States and Atripla, Truvada and Viread in Canada could be substantially shortened. Further, if all of the patents covering those products are invalidated, the FDA or Canadian Ministry of Health could approve the requests to manufacture a generic version of such products in the United States or Canada, respectively, prior to the expiration date of those patents.

Department of Justice Investigation

In June 2011, we received a subpoena from the United States Attorney's Office for the Northern District of California requesting documents related to the manufacture, and related quality and distribution practices, of Atripla, Emtriva, Hepsera, Letairis, Truvada, Viread and Complera. We have been cooperating and will continue to cooperate with this governmental inquiry.

Interference Proceedings and Litigation with Idenix Pharmaceuticals, Inc.

In February 2012, we received notice that the United States Patent and Trademark Office (PTO) had declared an Interference between our U.S. Patent No. 7,429,572 and Idenix Pharmaceuticals, Inc.'s (Idenix) pending patent application no. 12/131868. An Interference is an administrative proceeding before the PTO designed to determine who was the first to invent the subject matter being claimed by both parties. Our patent covers metabolites of GS-7977 and RG7128. Idenix is attempting to claim a class of compounds, including these metabolites, in their pending patent application. In the course of this proceeding, both parties will be called upon to submit evidence of the date they conceived of their respective inventions. The Interference will determine who was first to invent these compounds and therefore who is entitled to the patent claiming these compounds. If the administrative law judge determines Idenix is entitled to these patent claims and it is determined that we have infringed those claims, we may be required to obtain a license from, and pay royalties to, Idenix to commercialize GS-7977 and RG7128. Any determination by the PTO can be challenged by either party in U.S. Federal Court.

In June 2012, we met with Idenix in mandatory settlement discussions. The parties were unable to settle the Interference due to our widely divergent views on the strength of our respective positions, on whether we need a license to Idenix's patents and on whether Idenix needs a license to Gilead patents to develop and manufacture its pipeline products. We believe the Idenix patent involved in the Interference and similar U.S. and foreign patents claiming the same compounds and metabolites are invalid. As a result, we filed an Impeachment Action in Canadian Federal Court to invalidate the Idenix CA2490191 patent, which is the Canadian patent that corresponds to the Idenix U.S. Patent No. 7608600 and the Idenix patent application that is the subject of the Interference. We also filed a similar legal action in the Federal Court of Norway seeking to invalidate the corresponding Norwegian patent. We expect to bring similar action in other countries in 2012 or early 2013. Idenix has not been awarded patents on these compounds and metabolites in other European countries, Japan, and China. In the event such patents issue, we expect to challenge them in proceedings similar to those we invoked in Canada and Norway.

Contract Arbitration

In March 2012, Jeremy Clark, a former employee of Pharmasset, Inc. (Pharmasset), which we acquired in January 2012, and inventor of U.S. Patent No. 7,429,572, filed a demand for arbitration in his lawsuit against Pharmasset and Dr. Raymond Schinazi. Mr. Clark initially filed the lawsuit against Pharmasset and Dr. Schinazi in Alabama District Court in February 2008 seeking to void the assignment provision in his employment agreement and assert ownership of U.S. Patent No. 7,429,572, which claims metabolites of GS-7977 and RG7128. In December 2008, the court ordered a stay of the litigation pending the outcome of an arbitration proceeding required by Mr. Clark's employment agreement. Instead of proceeding with arbitration, Mr. Clark filed two additional lawsuits in September 2009 and June 2010, both of which were subsequently dismissed by the court. In September 2010, Mr. Clark filed a motion seeking reconsideration of the court's December 2008 order which was denied by the court. In December 2011, Mr. Clark filed a motion to appoint a special prosecutor. In February 2012, the Alabama Court issued an order requiring Mr. Clark to enter arbitration or risk dismissal of his case. Mr. Clark filed a demand for arbitration in March 2012. We cannot predict the outcome of the arbitration. If Mr. Clark's prior assignment of this patent to Pharmasset is voided by the arbitration panel, and he is ultimately found to be the owner of the 7,429,572 patent and it is determined that we have infringed the patent, we may be required to obtain a license from and pay royalties to Mr. Clark to commercialize GS-7977 and RG7128.

Other Matters

We are a party to various legal actions that arose in the ordinary course of our business. We do not believe that any of such legal actions will have a material adverse impact on our consolidated business, financial position or results of operations.

ITEM 1A. RISK FACTORS

In evaluating our business, you should carefully consider the following risks in addition to the other information in this Quarterly Report on Form 10-Q. A manifestation of any of the following risks could materially and adversely affect our business, results of operations and financial condition. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. It is not possible to predict or identify all such factors and, therefore, you should not consider the following risks to be a complete statement of all the potential risks or uncertainties that we face.

The public announcement of data from clinical studies evaluating GS-7977 and GS-5885 in HCV-infected patients is likely to cause significant volatility in our stock price. If the development of GS-7977 alone or in combination with GS-5885 is delayed or discontinued, our stock price could decline significantly.

During the fourth quarter of 2012 and 2013, we expect to receive a significant amount of data from clinical trials evaluating GS-7977, an investigational nucleotide analog we acquired through our purchase of Pharmasset Inc. (Pharmasset), alone or in combination with other direct acting antivirals in HCV-infected individuals across genotypes. In February 2012, we announced that the majority of HCV genotype 1 patients with a prior “null” response to an interferon-containing regimen enrolled in an arm of our ongoing ELECTRON study experienced viral relapse within four weeks of completing 12 weeks of treatment with GS-7977 plus ribavirin. In April 2012, we announced data from our ELECTRON and QUANTUM studies. These studies found that 88 and 53 percent of genotype 1 patients and treatment-naïve patients, respectively, taking a 12-week all-oral regimen of GS-7977 and ribavirin achieved a sustained viral response four weeks (SVR-4) after the completion of a 12-week course of therapy. In July 2012, we announced data from two Phase 2 studies evaluating a 24-week course of therapy with GS-7977 and ribavirin in treatment-naïve genotype 1 patients. In the QUANTUM study, 53 percent of the patients achieved SVR-4 after the completion of a 24-week course of therapy. The second study was conducted by the National Institute of Allergy and Infectious Diseases in a cohort of predominantly African American patients, a population which has historically been more difficult to treat for HCV. One hundred percent of the patients in this cohort who completed a 24-week course of therapy achieved SVR-4 after completion of therapy. These data indicate that the treatment of genotype 1 patients with GS-7977 plus ribavirin for 12 or 24 weeks is sufficient to cure the majority, but not all genotype 1 patients, of their disease.

In April 2012, we also announced data from our ATOMIC study, which found that 90 percent of genotype 1 HCV patients achieved a sustained viral response 12 weeks after a 12-week course of therapy with GS-7977 plus ribavirin and interferon. Also in April 2012, Bristol-Myers Squibb Company (BMS) announced data from its Phase 2 study evaluating GS-7977 in combination with daclatasvir, an investigational NS5A inhibitor, with and without ribavirin in genotype 1 and genotype 2 and 3 treatment-naïve HCV infected patients. The data showed that 100% of genotype 1 and 91% of genotype 2 and 3 patients achieved SVR-4 after the completion of a 24-week course of this treatment regimen.

Based on the data described above, we have worked with the U.S. Food and Drug Administration (FDA) and European regulators to agree upon a Phase 3 program for GS-7977 and our investigational NS5A inhibitor, GS-5885. Our new drug application (NDA) for GS-7977 will be supported by four Phase 3 studies named Fission, Positron, Fusion and Neutrino. Fission is the first study in 500 genotype 2 and 3 naïve patients comparing 12 weeks of treatment with GS-7977 and ribavirin to the current standard of care of 24 weeks of treatment with interferon and ribavirin. The second study, Positron, is also comparing 12 weeks of treatment with GS-7977 and ribavirin in 240 genotype 2 and 3 interferon intolerant/ineligible patients to placebo. The Fusion study will include 200 genotype 2 and 3 treatment experienced patients exploring 12 or 16 weeks duration of treatment with GS-7977 and ribavirin. Neutrino, the fourth Phase 3 study, is a single arm study evaluating a 12 week course of GS-7977, interferon and ribavirin in 300 genotype 1, 4, 5 and 6 infected-patients. All four studies are fully enrolled, and all patients have started therapy. Assuming data from the studies are positive, we anticipate being able to file for regulatory approvals for GS-7977 in the second quarter of 2013. If successful, we expect the initial indication to be for 12 weeks of treatment with GS-7977 and ribavirin in genotype 2 and 3 patients and for 12 weeks of treatment with GS-7977, interferon and ribavirin in genotype 1, 4, 5 and 6 patients.

In parallel, we are also advancing GS-7977 in combination with GS-5885 for the treatment of genotype 1 patients. We have developed two formulations of GS-7977 and GS-5885 co-formulated into a single fixed-dose combination tablet. The investigational new drug application on the first fixed-dose combination was filed in June 2012, and a Phase 1 study evaluating the bioavailability of the active drugs was initiated in July 2012. We are enrolling patients in a Phase 3 study evaluating the fixed-dose combination with and without ribavirin for either 12 or 24 weeks in treatment-naïve genotype-1 infected patients. These data will allow us to decide on the design of the second confirmatory study supporting the NDA of the GS-7977 and GS-5885 fixed-dose combination. If treatment of genotype 1-infected patients with the GS-7977 and GS-5885 fixed-dose combination for 12 weeks results in acceptably high SVR4 rates, then the second confirmatory study could be initiated in the first half of 2013. If the data from the second study is also positive, we anticipate being able to file for regulatory approval of the fixed-dose combination by mid-2014.

Development programs, including the development programs described above, are subject to numerous risks that could result in developmental and regulatory delays or in a decision to discontinue further development of GS-7977 and/or GS-5885. As a result, we may not complete our clinical studies of GS-7977 and GS-5885 or any regulatory filings in the currently anticipated timelines or at all. In addition, regulatory authorities require that patients have a sustained viral response for 12 weeks after the cessation of therapy to be considered “cured” of HCV. If data from any of the clinical studies indicate that a smaller than anticipated number of patients achieved a sustained viral response at 4, 12 or 24 weeks post-treatment, our development programs for the treatment of HCV may be delayed or discontinued and our stock price may decline significantly. Further, developing drugs for the treatment of HCV is an extremely competitive field and a significant number of drugs are under development. Depending on the length of any delay we may experience in our development of GS-7977 and GS-5885, other companies who are developing competitive compounds in HCV may be able to progress their development timelines and potentially bring compounds to market before GS-7977 and/or GS-5885 or shortly thereafter.

A substantial portion of our revenues is derived from sales of our HIV products, particularly Atripla and Truvada. If we are unable to maintain or continue increasing sales of these products, our results of operations may be adversely affected.

We are currently dependent on sales of our products for the treatment of HIV infection, particularly Atripla and Truvada, to support our existing operations. Our HIV products contain tenofovir disoproxil fumarate and/or emtricitabine, which belong to the nucleoside class of antiviral therapeutics. Were the treatment paradigm for HIV to change, causing nucleoside-based therapeutics to fall out of favor, or if we were unable to maintain or continue increasing our HIV product sales, our results of operations would likely suffer and we would likely need to scale back our operations, including our spending on research and development (R&D) efforts. For the quarter ended September 30, 2012, Atripla and Truvada product sales together were $1.67 billion, or 69% of our total revenues. We may not be able to sustain or increase the growth rate of sales of our HIV products, especially Atripla, Truvada and Complera/Eviplera, for any number of reasons including, but not limited to, the following:

- As our HIV products are used over a longer period of time in many patients and in combination with other products, and additional studies are conducted, new issues with respect to safety, resistance and interactions with other drugs may arise, which could cause us to provide additional warnings or contraindications on our labels, narrow our approved indications or halt sales of a product, each of which could reduce our revenues.
- As our HIV products mature, private insurers and government payers often reduce the amount they will reimburse patients for these products, which increases pressure on us to reduce prices.
- A large part of the market for our HIV products consists of patients who are already taking other HIV drugs. If we are not successful in encouraging physicians to change patients' regimens to include our HIV products, the sales of our HIV products will be limited.
- As generic HIV products are introduced into major markets, our ability to maintain pricing and market share may be affected.

If we fail to commercialize new products or expand the indications for existing products, our prospects for future revenues may be adversely affected.

If we do not introduce new products to market or increase sales of our existing products, we will not be able to increase or maintain our total revenues and continue to expand our R&D efforts. Drug development is inherently risky and many product candidates fail during the drug development process. For example, in January 2011, we announced our decision to terminate our Phase 3 clinical trial of ambrisentan in patients with idiopathic pulmonary fibrosis (IPF). In April 2011, we announced our decision to terminate our Phase 3 clinical trial of aztreonam for inhalation solution for the treatment of cystic fibrosis (CF) in patients with Burkholderia spp. In addition, our marketing application for our single tablet regimen of elvitegravir, cobicistat, tenofovir disoproxil fumarate and emtricitabine for the treatment of HIV in treatment-naïve patient may not be approved by the European Medicines Agency (EMA) or other foreign regulatory agencies, and our new drug applications for elvitegravir for the treatment of HIV in treatment-experienced patients and cobicistat, a pharmacoenhancing or “boosting” agent, may not be approved by the FDA, EMA or other foreign regulatory authorities. Even if marketing approval is granted for any of these products, there may be significant limitations on their use. Further, we may be unable to file our marketing applications for new products, including GS-7977 and GS-5885 in the currently anticipated timelines and marketing approval for the products may not be granted.

Our results of operations will be adversely affected by current and potential future healthcare reforms.

Legislative and regulatory changes to government prescription drug procurement and reimbursement programs occur relatively frequently in the United States and foreign jurisdictions. In March 2010, healthcare reform legislation was adopted in the United States. As a result, we are required to further rebate or discount products reimbursed or paid for by various public payers, including Medicaid and other entities eligible to purchase discounted products through the 340B Drug Pricing Program under the Public Health Service Act, such as AIDS Drug Assistance Programs (ADAPs). The discounts, rebates and fees in the legislation that impacted us include:

- our minimum base rebate amount owed to Medicaid on products reimbursed by Medicaid has been increased by 8%, and the discounts or rebates we owe to ADAPs and other Public Health Service entities which reimburse or purchase our products have also been increased by 8%;
- we are required to extend rebates to patients receiving our products through Medicaid managed care organizations;
- we are required to provide a 50% discount on products sold to patients while they are in the Medicare Part D "donut hole;" and
- we, along with other pharmaceutical manufacturers of branded drug products, are required to pay a portion of a new industry fee (also known as the pharmaceutical excise tax) of $2.5 billion for 2011, calculated based on select government sales during the 2010 calendar year as a percentage of total industry government sales.

The amount of the industry fee imposed on the pharmaceutical industry as a whole will increase to $2.8 billion in 2012, with additional increases over the next several years to a peak of $4.1 billion per year in 2018, and then decrease to $2.8 billion in 2019 and thereafter. As the amount of the industry fee increases, our product sales increase and drug patents expire on major drugs, such as Lipitor, we expect our portion of the excise tax to increase as well. We estimate our portion of the pharmaceutical excise tax to be $80-$100 million in 2012, compared to approximately $50 million in 2011. The excise tax is not tax deductible.

Further, even though not addressed in the healthcare reform legislation, discussions continue at the federal level on legislation that would either allow or require the federal government to directly negotiate price concessions from pharmaceutical manufacturers or set minimum requirements for Medicare Part D pricing.

In addition, state Medicaid programs could request additional supplemental rebates on our products as a result of the increase in the federal base Medicaid rebate. Private insurers could also use the enactment of these increased rebates to exert pricing pressure on our products, and to the extent that private insurers or managed care programs follow Medicaid coverage and payment developments, the adverse effects may be magnified by private insurers adopting lower payment schedules.

Our existing products are subject to reimbursement from government agencies and other third parties. Pharmaceutical pricing and reimbursement pressures may reduce profitability.

Successful commercialization of our products depends, in part, on the availability of governmental and third-party payer reimbursement for the cost of such products and related treatments. Government health administration authorities, private health insurers and other organizations generally provide reimbursement. In the United States, the European Union and other significant or potentially significant markets for our products and product candidates, government authorities and third-party payers are increasingly attempting to limit or regulate the price of medical products and services, particularly for new and innovative products and therapies, which has resulted in lower average selling prices.

A significant portion of our sales of the majority of our products are subject to significant discounts from list price and rebate obligations. In the United States, state ADAPs, which purchase a significant portion of our HIV products, rely on federal, supplemental federal and state funding to help fund purchases of our products. Given the current economic downturn, we have experienced a shift in our payer mix as patients previously covered by private insurance move to public reimbursement programs that require rebates or discounts from us or as patients previously covered by one public reimbursement program move to another public reimbursement program that requires greater rebates or discounts from us. As a result of this shift, revenue growth may be lower than prescription growth. If federal and state funds are not available in amounts sufficient to support the number of patients that rely on ADAPs, sales of our HIV products could be negatively impacted which would reduce our revenues. For example, during the first quarter of 2011, the state budget crisis in Florida led to a temporary movement of patients who were previously covered by

Florida's ADAP into industry-supported patient assistance programs. In prior quarters, due to the insufficiency of federal and state funds and as many states reduced eligibility criteria, we saw an increase in the number of patients on state ADAP wait lists, and we may see similar increases in future periods. Until these patients are enrolled in ADAP, they generally receive product from industry-supported patient assistance programs or are unable to access treatment. The increased emphasis on managed healthcare in the United States and on country and regional pricing and reimbursement controls in the European Union will put additional pressure on product pricing, reimbursement and usage, which may adversely affect our product sales and profitability. These pressures can arise from rules and practices of managed care groups, judicial decisions and governmental laws and regulations related to Medicare, Medicaid and healthcare reform, pharmaceutical reimbursement policies and pricing in general.

In Europe, the success of our commercialized products, and any other product candidates we may develop, will depend largely on obtaining and maintaining government reimbursement, because in many European countries patients are unlikely to use prescription drugs that are not reimbursed by their governments. In addition, negotiating prices with governmental authorities can delay commercialization by 12 months or more. Reimbursement policies may adversely affect our ability to sell our products on a profitable basis. In many international markets, governments control the prices of prescription pharmaceuticals, including through the implementation of reference pricing, price cuts, rebates, revenue-related taxes and profit control, and they expect prices of prescription pharmaceuticals to decline over the life of the product or as volumes increase.

Recently, many countries in the European Union have increased the amount of discounts required on our products, and these efforts could continue as countries attempt to manage healthcare expenditures, especially in light of the severe fiscal and debt crises experienced by many countries in the European Union. For example, in June 2010, Spain imposed an incremental discount on all branded drugs and in August 2010, Germany increased the rebate on prescription pharmaceuticals. As generic drugs come to market, we may face price decreases for our products in some countries in the European Union. Further, cost containment pressures in the European Union could lead to delays in the treatment of patients and also delay pricing approval, which could negatively impact the commercialization of new products.

Approximately 41% of our product sales occur outside the United States, and currency fluctuations and hedging expenses may cause our earnings to fluctuate, which could adversely affect our stock price.

Because a significant percentage of our product sales are denominated in foreign currencies, primarily the Euro, we face exposure to adverse movements in foreign currency exchange rates. When the U.S. dollar strengthens against these foreign currencies, the relative value of sales made in the respective foreign currency decreases. Conversely, when the U.S. dollar weakens against these currencies, the relative value of such sales increases. Overall, we are a net receiver of foreign currencies and, therefore, benefit from a weaker U.S. dollar and are adversely affected by a stronger U.S. dollar relative to those foreign currencies in which we transact significant amounts of business.

We use foreign currency exchange forward and option contracts to hedge a percentage of our forecasted international sales, primarily those denominated in the Euro. We also hedge certain monetary assets and liabilities denominated in foreign currencies, which reduces but does not eliminate our exposure to currency fluctuations between the date a transaction is recorded and the date that cash is collected or paid. We cannot predict future fluctuations in the foreign currency exchange rate of the U.S. dollar. If the U.S. dollar appreciates significantly against certain currencies and our hedging program does not sufficiently offset the effects of such appreciation, our results of operations will be adversely affected and our stock price may decline.

Additionally, the expenses that we recognize in relation to our hedging activities can also cause our earnings to fluctuate. The level of hedging expenses that we recognize in a particular period is impacted by the changes in interest rate spreads between the foreign currencies that we hedge and the U.S. dollar.

Our inability to accurately estimate demand for our products, as well as sales fluctuations as a result of inventory levels held by wholesalers, pharmacies and non-retail customers make it difficult for us to accurately forecast sales and may cause our earnings to fluctuate, which could adversely affect our financial results and our stock price.

In the quarter ended September 30, 2012, approximately 78% of our product sales in the United States were to three wholesalers, Cardinal Health, Inc., McKesson Corp. and AmerisourceBergen Corp. The U.S. wholesalers with whom we have entered into inventory management agreements make estimates to determine end user demand and may not be completely effective in matching their inventory levels to actual end user demand. As a result, changes in inventory levels held by those wholesalers can cause our operating results to fluctuate unexpectedly if our sales to these wholesalers do not match end user demand. In addition, inventory is held at retail pharmacies and other non-wholesale locations with whom we have no inventory management agreements and no control over buying patterns. Adverse changes in economic conditions or other factors may cause retail pharmacies to reduce their inventories of our products, which would reduce their orders from wholesalers and, consequently, the wholesalers' orders from us, even if end user demand has not changed. For example, during the fourth quarter of 2010, our wholesalers increased their inventory levels for our antiviral products. In the first quarter of 2011, our wholesalers drew down on their inventory such that inventory levels for our antiviral products moved to the lower end of the contractual boundaries set by our inventory management agreements. As inventory in the distribution channel fluctuates from quarter to quarter, we may continue to see fluctuations in our earnings and a mismatch between prescription demand for our products and our revenues.

In addition, the non-retail sector in the United States, which includes government institutions, including state ADAPs, correctional facilities and large health maintenance organizations, tends to be even less consistent in terms of buying patterns and often causes quarter over quarter fluctuations that do not necessarily mirror patient demand. Federal and state budget pressures, as well as the annual grant cycles for federal and state ADAP funds, may cause ADAP purchasing patterns to not reflect patient demand. For example, in the first and second quarters of 2012, we observed large non-retail purchases by a number of state ADAPs which exceeded patient demand. We believe such purchases were driven by the grant cycle for federal ADAP funds, the early communication of Ryan White Federal Funds and the desire by state ADAPs to reduce patient wait lists, which led to a significant reduction in ADAP purchasing in the third quarter of 2012. As a result, we expect to continue to experience fluctuations in the purchasing patterns of our non-retail customers which may result in fluctuations in our product sales, revenues and earnings in the future.

In light of the global economic downturn and budget crises faced by many European countries, we have observed variations in purchasing patterns induced by cost containment measures in Europe. We believe these measures have caused some government agencies and other purchasers to reduce inventory of our products in the distribution channels, which has decreased our revenues and caused fluctuations in our product sales and earnings. We may continue to see this trend in the future.

We face significant competition.

We face significant competition from large pharmaceutical and biotechnology companies, most of whom have substantially greater resources than we do. In addition, our competitors have more products and have operated in the fields in which we compete for longer than we have. Our HIV products compete primarily with products from the joint venture established by GlaxoSmithKline Inc. (GSK) and Pfizer Inc. (Pfizer) which markets fixed-dose combination products that compete with Atripla, Truvada and Complera/Eviplera and Stribild. For example, lamivudine, marketed by this joint venture, is competitive with emtricitabine, the active pharmaceutical ingredient of Emtriva and a component of Atripla, Truvada and Complera/Eviplera.

We also face competition from generic HIV products. In May 2010, the compound patent covering Epivir (lamivudine) itself expired in the United States, and generic lamivudine is now available in the United States, Spain, Portugal and Italy. We expect that generic versions of lamivudine will be launched in other countries within the European Union. In May 2011, a generic version of Combivir (lamivudine and zidovudine) was approved and was recently launched in the United States. In addition, in late 2011, generic tenofovir also became available in Turkey, which resulted in an increase in the rebate for Viread in Turkey. We also expect competition from a generic version of Sustiva (efavirenz), a component of our Atripla, to be available in the United States, Europe and Canada in 2013, which may negatively impact sales of our HIV products.

For Viread and Hepsera for treatment of chronic hepatitis B, we compete primarily with products produced by GSK, BMS and Novartis Pharmaceuticals Corporation (Novartis) in the United States, the European Union and China. For AmBisome, we compete primarily with products produced by Merck & Co., Inc. (Merck) and Pfizer. In addition, we are aware of at least three lipid formulations that claim similarity to AmBisome becoming available outside of the United States, including the possible entry of such formulations in Greece and Taiwan. These formulations may reduce market demand for AmBisome. Furthermore, the manufacture of lipid formulations of amphotericin B is very complex and if any of these formulations are found to be unsafe, sales of AmBisome may be negatively impacted by association. Letairis competes directly with a product produced by Actelion Pharmaceuticals US, Inc. and indirectly with pulmonary arterial hypertension products from United Therapeutics Corporation and Pfizer. Ranexa competes predominantly with generic compounds from three distinct classes of drugs, beta-blockers, calcium channel blockers and long-acting nitrates for the treatment of chronic angina in the United States. Cayston competes with a product marketed by Novartis. Tamiflu competes with products sold by GSK and generic competitors.

In addition, a number of companies are pursuing the development of technologies which are competitive with our existing products or research programs. These competing companies include specialized pharmaceutical firms and large pharmaceutical companies acting either independently or together with other pharmaceutical companies. Furthermore, academic institutions, government agencies and other public and private organizations conducting research may seek patent protection and may establish collaborative arrangements for competitive products or programs.

If significant safety issues arise for our marketed products or our product candidates, our future sales may be reduced, which would adversely affect our results of operations.
The data supporting the marketing approvals for our products and forming the basis for the safety warnings in our product labels were obtained in controlled clinical trials of limited duration and, in some cases, from post-approval use. As our products are used over longer periods of time by many patients with underlying health problems, taking numerous other medicines, we expect to continue to find new issues such as safety, resistance or drug interaction issues, which may require us to provide additional warnings or contraindications on our labels or narrow our approved indications, each of which could reduce the market acceptance of these products.
Our product Letairis, which was approved by the FDA in June 2007, is a member of a class of compounds called endothelin receptor antagonists (ERAs) which pose specific risks, including serious risks of birth defects. Because of these risks, Letairis is available only through the Letairis Education and Access Program (LEAP), a restricted distribution program intended to help physicians and patients learn about the risks associated with the product and assure appropriate use of the product. As the product is used by additional patients, we may discover new risks associated with Letairis which may result in changes to the distribution program and additional restrictions on the use of Letairis which may decrease demand for the product.
Regulatory authorities have been moving towards more active and transparent pharmacovigilance and are making greater amounts of stand-alone safety information directly available to the public through websites and other means, e.g. periodic safety update report summaries, risk management plan summaries and various adverse event data. Safety information, without the appropriate context and expertise, may be misinterpreted and lead to misperception or legal action which may potentially cause our product sales or stock price to decline.
Further, if serious safety, resistance or drug interaction issues arise with our marketed products, sales of these products could be limited or halted by us or by regulatory authorities and our results of operations would be adversely affected.
Our operations depend on compliance with complex FDA and comparable international regulations. Failure to obtain broad approvals on a timely basis or to maintain compliance could delay or halt commercialization of our products.
The products we develop must be approved for marketing and sale by regulatory authorities and, once approved, are subject to extensive regulation by the FDA, the EMA and comparable regulatory agencies in other countries. We are continuing clinical trials for Atripla, Truvada, Viread, Hepsera, Complera/Eviplera, Stribild, Emtriva, AmBisome, Letairis, Ranexa and Cayston for currently approved and additional uses. We anticipate that we will file for marketing approval in additional countries and for additional indications and products over the next several years. These products may fail to receive such marketing approvals on a timely basis, or at all.
Further, our marketed products and how we manufacture and sell these products are subject to extensive regulation and review. Discovery of previously unknown problems with our marketed products or problems with our manufacturing or promotional activities may result in restrictions on our products, including withdrawal of the products from the market. If we fail to comply with applicable regulatory requirements, including those related to promotion and manufacturing, we could be subject to penalties including fines, suspensions of regulatory approvals, product recalls, seizure of products and criminal prosecution.
For example, under FDA rules, we are often required to conduct post-approval clinical studies to assess a known serious risk, signals of serious risk or to identify an unexpected serious risk and implement a Risk Evaluation and Mitigation Strategy for our products, which could include a medication guide, patient package insert, a communication plan to healthcare providers or other elements as the FDA deems are necessary to assure safe use of the drug, which could include imposing certain restrictions on the distribution or use of a product. Failure to comply with these or other requirements, if imposed on a sponsor by the FDA, could result in significant civil monetary penalties and our operating results may be adversely affected.

The results and anticipated timelines of our clinical trials are uncertain and may not support continued development of a product pipeline, which would adversely affect our prospects for future revenue growth.

We are required to demonstrate the safety and efficacy of products that we develop for each intended use through extensive preclinical studies and clinical trials. The results from preclinical and early clinical studies do not always accurately predict results in later, large-scale clinical trials. Even successfully completed large-scale clinical trials may not result in marketable products. If any of our product candidates fails to achieve its primary endpoint in clinical trials, if safety issues arise or if the results from our clinical trials are otherwise inadequate to support regulatory approval of our product candidates, commercialization of that product candidate could be delayed or halted. For example, in January 2011, we announced our decision to terminate our Phase 3 clinical trial of ambrisentan in patients with IPF and, in April 2011, we announced our decision to terminate our Phase 3 clinical trial of aztreonam for inhalation solution for the treatment of CF in patients with Burkholderia spp. In addition, we may also face challenges in clinical trial protocol design. If the clinical trials for any of the product candidates in our pipeline are delayed or terminated, our prospects for future revenue growth would be adversely impacted. For example, we face numerous risks and uncertainties with our product candidates, including GS-7977 and GS-5885 for the treatment of hepatitis C; aztreonam for inhalation solution for the treatment of bronchiectasis; ranolazine for the treatment of incomplete revascularization post-percutaneous coronary intervention and type II diabetes; and GS-1101 for the treatment of chronic lymphocytic leukemia, each currently in Phase 3 clinical trials, that could prevent completion of development of these product candidates. These risks include our ability to enroll patients in clinical trials, the possibility of unfavorable results of our clinical trials, the need to modify or delay our clinical trials or to perform additional trials and the risk of failing to obtain FDA and other regulatory body approvals. As a result, our product candidates may never be successfully commercialized. Further, we may make a strategic decision to discontinue development of our product candidates if, for example, we believe commercialization will be difficult relative to other opportunities in our pipeline. If these programs and others in our pipeline cannot be completed on a timely basis or at all, then our prospects for future revenue growth may be adversely impacted. In addition, clinical trials involving our commercial products could raise new safety issues for our existing products, which could in turn decrease our revenues and harm our business.

Due to our reliance on third-party contract research organizations to conduct our clinical trials, we are unable to directly control the timing, conduct, expense and quality of our clinical trials.

We extensively outsource our clinical trial activities and usually perform only a small portion of the start-up activities in-house. We rely on independent third-party contract research organizations (CROs) to perform most of our clinical studies, including document preparation, site identification, screening and preparation, pre-study visits, training, program management and bioanalytical analysis. Many important aspects of the services performed for us by the CROs are out of our direct control. If there is any dispute or disruption in our relationship with our CROs, our clinical trials may be delayed. Moreover, in our regulatory submissions, we rely on the quality and validity of the clinical work performed by third-party CROs. If any of our CROs' processes, methodologies or results were determined to be invalid or inadequate, our own clinical data and results and related regulatory approvals could be adversely impacted.

Expenses associated with clinical trials may cause our earnings to fluctuate, which could adversely affect our stock price.

The clinical trials required for regulatory approval of our products, as well as clinical trials we are required to conduct after approval, are very expensive. It is difficult to accurately predict or control the amount or timing of these expenses from quarter to quarter, and the FDA and/or other regulatory agencies may require more clinical testing than we originally anticipated. Uneven and unexpected spending on these programs, including on the clinical trials that will be necessary to advance GS-7977, GS-5885 and our other product candidates for the treatment of HCV, may cause our operating results to fluctuate from quarter to quarter, and our stock price may decline.

We depend on relationships with other companies for sales and marketing performance, development and commercialization of product candidates and revenues. Failure to maintain these relationships, poor performance by these companies or disputes with these companies could negatively impact our business.

We rely on a number of significant collaborative relationships with major pharmaceutical companies for our sales and marketing performance in certain territories. These include collaborations with BMS for Atripla in the United States, Europe and Canada; F. Hoffmann-La Roche Ltd. (together with Hoffmann-La Roche Inc., Roche) for Tamiflu worldwide; and GSK for ambrisentan in territories outside of the United States. In some countries, we rely on international distributors for sales of Truvada, Viread, Hepsera, Emtriva and AmBisome. Some of these relationships also involve the clinical development of these products by our partners. Reliance on collaborative relationships poses a number of risks, including the risk that:

- we are unable to control the resources our corporate partners devote to our programs or products;
- disputes may arise with respect to the ownership of rights to technology developed with our corporate partners;
- disagreements with our corporate partners could cause delays in, or termination of, the research, development or commercialization of product candidates or result in litigation or arbitration;
- contracts with our corporate partners may fail to provide significant protection or may fail to be effectively enforced if one of these partners fails to perform;
- our corporate partners have considerable discretion in electing whether to pursue the development of any additional products and may pursue alternative technologies or products either on their own or in collaboration with our competitors;
- our corporate partners with marketing rights may choose to pursue competing technologies or to devote fewer resources to the marketing of our products than they do to products of their own development; and
- our distributors and our corporate partners may be unable to pay us, particularly in light of current economic conditions.

Given these risks, there is a great deal of uncertainty regarding the success of our current and future collaborative efforts. If these efforts fail, our product development or commercialization of new products could be delayed or revenues from products could decline.

We also rely on collaborative relationships with major pharmaceutical companies for development and commercialization of certain product candidates. Gilead (as successor to Pharmasset) is a party to a collaboration agreement with Roche to develop PSI-6130 and its prodrugs for the treatment of chronic HCV infection. The collaborative research efforts under this agreement ended on December 31, 2006. Roche later asked Pharmasset to consider whether Roche may have contributed to the inventorship of GS-7977 and whether Pharmasset has complied with the confidentiality provisions of the collaboration agreement. Pharmasset advised us that it carefully considered the issues raised by Roche and that it believed any such issues are without merit. We have also considered these issues and reached the same conclusion. However, if Roche were to successfully assert that it contributed to the inventorship of GS-7977 and either independently develop GS-7977 or file an abbreviated new drug application (ANDA) to market GS-7977, Roche could at some point in the future market that product and begin competing against us prior to the expiration of our patents for GS-7977. Such marketing activity by Roche could materially reduce the revenues we expect to receive from the sale of GS-7977, which could adversely affect our results of operations.

Under our April 2002 licensing agreement with GSK, we gave GSK the right to control clinical and regulatory development and commercialization of Hepsera in territories in Asia, Africa and Latin America. These include major markets for Hepsera, such as China, Japan, Taiwan and South Korea. In November 2009, we entered into an agreement with GSK that provided GSK with exclusive commercialization rights and registration responsibilities for Viread for the treatment of chronic hepatitis B in China. In October 2010, we granted similar rights to GSK in Japan and Saudi Arabia. The success of Hepsera and Viread for the treatment of chronic hepatitis B in these territories depends almost entirely on the efforts of GSK. In this regard, GSK promotes Epivir-HBV/Zeffix, a product that competes with Hepsera and Viread for the treatment of chronic hepatitis B. Consequently, GSK's marketing strategy for Hepsera and Viread for the treatment of chronic hepatitis B may be influenced by its promotion of Epivir-HBV/Zeffix. We receive royalties from GSK equal to a percentage of GSK's net sales of Hepsera and Viread for the treatment of chronic hepatitis B as well as net sales of GSK's Epivir-HBV/Zeffix. If GSK fails to devote sufficient resources to, or does not succeed in developing or commercializing Hepsera or Viread for the treatment of chronic hepatitis B in its territories, our potential revenues in these territories may be substantially reduced.

In addition, Cayston and Letairis are distributed through third-party specialty pharmacies, which are pharmacies specializing in the dispensing of medications for complex or chronic conditions that may require a high level of patient education and ongoing counseling. The use of specialty pharmacies requires significant coordination with our sales and marketing, medical affairs, regulatory affairs, legal and finance organizations and involves risks, including but not limited to risks that these specialty pharmacies will:

- not provide us with accurate or timely information regarding their inventories, patient data or safety complaints;
- not effectively sell or support Cayston or Letairis;
- not devote the resources necessary to sell Cayston or Letairis in the volumes and within the time frames that we expect;
- not be able to satisfy their financial obligations to us or others; or
- cease operations.

We also rely on a third party to administer LEAP, the restricted distribution program designed to support Letairis. This third party provides information and education to prescribers and patients on the risks of Letairis, confirms insurance coverage and investigates alternative sources of reimbursement or assistance, ensures fulfillment of the risk management requirements mandated for Letairis by the FDA and coordinates and controls dispensing to patients through the third-party specialty pharmacies. Failure of this third party or the specialty pharmacies that distribute Letairis to perform as expected may result in regulatory action from the FDA or decreased Letairis sales, either of which would harm our business.

Further, Cayston may only be taken by patients using a specific inhalation device that delivers the drug to the lungs of patients. Our ongoing distribution of Cayston is entirely reliant upon the manufacturer of that device. For example, the manufacturer could encounter other issues with regulatory agencies related to the device or be unable to supply sufficient quantities of this device. In addition, the manufacturer may not be able to provide adequate warranty support for the device after it has been distributed to patients. With respect to distribution of the drug and device to patients, we are reliant on the capabilities of specialty pharmacies. For example, the distribution channel for drug and device is complicated and requires coordination. The reimbursement approval processes associated with both drug and device are similarly complex. If the device manufacturer is unable to obtain reimbursement approval or receives approval at a lower-than-expected price, sales of Cayston may be adversely affected. Any of the previously described issues may limit the sales of Cayston, which would adversely affect our financial results.

Our success will depend to a significant degree on our ability to protect our patents and other intellectual property rights both domestically and internationally. We may not be able to obtain effective patents to protect our technologies from use by competitors and patents of other companies could require us to stop using or pay for the use of required technology.

Patents and other proprietary rights are very important to our business. Our success will depend to a significant degree on our ability to:

- obtain patents and licenses to patent rights;
- preserve trade secrets;
- defend against infringement and efforts to invalidate our patents; and
- operate without infringing on the proprietary rights of others.

If we have a properly drafted and enforceable patent, it can be more difficult for our competitors to use our technology to create competitive products and more difficult for our competitors to obtain a patent that prevents us from using technology we create. As part of our business strategy, we actively seek patent protection both in the United States and internationally and file additional patent applications, when appropriate, to cover improvements in our compounds, products and technology.

We have a number of U.S. and foreign patents, patent applications and rights to patents related to our compounds, products and technology, but we cannot be certain that issued patents will be enforceable or provide adequate protection or that pending patent applications will result in issued patents. Patent applications are confidential for a period of time before a patent is issued. As a result, we may not know if our competitors filed patent applications for technology covered by our pending applications or if we were the first to invent or first to file an application directed toward the technology that is the subject of our patent applications. Competitors may have filed patent applications or received patents and may obtain additional patents and proprietary rights that block or compete with our products. In addition, if competitors file patent applications covering our technology, we may have to participate in interference proceedings or litigation to determine the right to a patent. Litigation and interference proceedings are unpredictable and expensive, such that, even if we are ultimately successful, our results of operations may be adversely affected by such events.

From time to time, certain individuals or entities may challenge our patents. For example, in 2007, the Public Patent Foundation filed requests for re-examination with the United States Patent and Trademark Office (PTO) challenging four of our patents related to tenofovir disoproxil fumarate, which is an active ingredient in Atripla, Truvada and Viread and Stribild. The PTO granted these requests and issued non-final rejections for the four patents, which is a step common in a proceeding to initiate the re-examination process. In 2008, the PTO confirmed the patentability of all four patents.

From time to time, we may become involved in disputes with inventors on our patents. For example, in March 2012, Jeremy Clark, a former employee of Pharmasset, which we acquired in January 2012, and inventor of U.S. Patent No. 7,429,572, filed a demand for arbitration in his lawsuit against Pharmasset and Dr. Raymond Schinazi. Mr. Clark initially filed the lawsuit against Pharmasset and Dr. Schinazi in February 2008 seeking to void the assignment provision in his employment agreement and assert ownership of U.S. Patent No. 7,429,572, which claims metabolites of GS-7977 and RG7128. In December 2008, the court ordered a stay of the litigation pending the outcome of an arbitration proceeding required by Mr. Clark's employment agreement. Instead of proceeding with arbitration, Mr. Clark filed two additional lawsuits in September 2009 and June 2010, both of which were subsequently dismissed by the court. In September 2010, Mr. Clark filed a motion seeking reconsideration of the court's December 2008 order which was denied by the court. In December 2011, Mr. Clark filed a motion to appoint a special prosecutor. In February 2012, the court issued an order requiring Mr. Clark to enter arbitration or risk dismissal of his case. Mr. Clark filed a demand for arbitration in March 2012. We cannot predict the outcome of the arbitration. If Mr. Clark's prior assignment of this patent to Pharmasset is voided by the arbitration panel, and he is ultimately found to be the owner of the 7,429,572 patent and it is determined that we have infringed the patent, we may be required to obtain a license from and pay royalties to Mr. Clark to commercialize GS-7977 and RG7128.

Patents do not cover the ranolazine compound, the active ingredient of Ranexa. Instead, when it was discovered that only a sustained release formulation of ranolazine would achieve therapeutic plasma levels, patents were obtained on those formulations and the characteristic plasma levels they achieve. Patents do not cover the active ingredients in AmBisome. In addition, we do not have patent filings in China or certain other Asian countries covering all forms of adefovir dipivoxil, the active ingredient in Hepsera. Asia is a major market for therapies for hepatitis B, the indication for which Hepsera has been developed.

We may obtain patents for certain products many years before marketing approval is obtained for those products. Because patents have a limited life, which may begin to run prior to the commercial sale of the related product, the commercial value of the patent may be limited. However, we may be able to apply for patent term extensions in some countries.

Generic manufacturers have sought and may continue to seek FDA approval to market generic versions of our products through an ANDA, the application form typically used by manufacturers seeking approval of a generic drug. Please see a description of our ANDA litigation in "Legal Proceedings" beginning on page 39.

Our success depends in large part on our ability to operate without infringing upon the patents or other proprietary rights of third parties.

If we infringe the patents of others, we may be prevented from commercializing products or may be required to obtain licenses from these third parties. We may not be able to obtain alternative technologies or any required license on reasonable terms or at all. If we fail to obtain these licenses or alternative technologies, we may be unable to develop or commercialize some or all of our products. For example, we are aware of a body of patents that may relate to our operation of LEAP, our restricted distribution program designed to support Letairis.

We own patents that claim GS-7977 as a chemical entity and its metabolites. However, the existence of issued patents does not guarantee our right to practice the patented technology or commercialize the patented product. Third parties may have or obtain rights to patents which they may claim could be used to prevent or attempt to prevent us from commercializing the patented product candidates obtained from the Pharmasset acquisition. For example, we are aware of patents and patent applications owned by other parties that might be alleged to cover the use of GS-7977. If these other parties are successful in obtaining valid and enforceable patents, and establishing our infringement of those patents, we could be prevented from selling GS-7977 unless we were able to obtain a license under such patents. If any license is needed it may not be available on commercially reasonable terms or at all.

In some instances, we may be required to defend our right to a patent on an invention through an Interference proceeding before the PTO. An Interference is an administrative proceeding before the PTO designed to determine who was the first to invent the subject matter being claimed by both parties. In February 2012, we received notice that the PTO had declared an Interference between our U.S. Patent No. 7,429,572 and Idenix Pharmaceuticals, Inc.'s (Idenix) pending patent application no. 12/131868. Our patent covers metabolites of GS-7977 and RG7128. Idenix is attempting to claim a class of compounds, including these metabolites, in their pending patent application. In the course of this proceeding, both parties will be called upon to submit evidence of the date they conceived of their respective inventions. The Interference will determine who was first to invent these compounds and therefore who is entitled to the patent claiming these compounds. If the administrative law judge determines Idenix is entitled to these patent claims and it is determined that we have infringed those claims, we may be required to obtain a license from, and pay royalties to, Idenix to commercialize GS-7977 and RG7128. Any determination by the judge can be challenged by either party in U.S. Federal Court.

In June 2012, we met with Idenix in mandatory settlement discussions. The parties were unable to settle the Interference due to our widely divergent views on the strength of our respective positions, on whether we need a license to Idenix's patents and whether Idenix needs a license to Gilead patents to develop and manufacture its pipeline products. We believe the Idenix patents involved in the Interference and similar U.S. and foreign patents claiming the same compounds and metabolites are invalid. As a result, we filed an Impeachment Action in Canadian Federal Court to invalidate the Idenix CA2490191 patent, which is the Canadian patent that corresponds to the Idenix U.S. Patent No. 7608600 and the Idenix patent application that is the subject of the Interference. We also filed a similar legal action in the Federal Court of Norway seeking to invalidate the corresponding Norwegian patent. We expect to bring similar action in other countries in 2012 or early 2013. Idenix has not been awarded patents on these compounds and metabolites in other European countries, Japan and China. In the event such patents issue, we expect to challenge them in proceedings similar to those we invoked in Canada and Norway.

Furthermore, we use significant proprietary technology and rely on unpatented trade secrets and proprietary know-how to protect certain aspects of our production and other technologies. Our trade secrets may become known or independently discovered by our competitors.

Manufacturing problems, including at our third-party manufacturers and corporate partners, could cause inventory shortages and delay product shipments and regulatory approvals, which may adversely affect our results of operations.

In order to generate revenue from our products, we must be able to produce sufficient quantities of our products to satisfy demand. Many of our products are the result of complex manufacturing processes. The manufacturing process for pharmaceutical products is also highly regulated and regulators may shut down manufacturing facilities that they believe do not comply with regulations.

Our products are either manufactured at our own facilities or by third-party manufacturers or corporate partners. We depend on third parties to perform manufacturing activities effectively and on a timely basis for the majority of our solid dose products. In addition, Roche, either by itself or through third parties, is responsible for manufacturing Tamiflu. We, our third-party manufacturers and our corporate partners are subject to current Good Manufacturing Practices (GMP), which are extensive regulations governing manufacturing processes, stability testing, record keeping and quality standards as defined by the FDA and the EMA. Similar regulations are in effect in other countries.

Our third-party manufacturers and corporate partners are independent entities who are subject to their own unique operational and financial risks which are out of our control. If we or any of these third-party manufacturers or corporate partners fail to perform as required, this could impair our ability to deliver our products on a timely basis or receive royalties or cause delays in our clinical trials and applications for regulatory approval. To the extent these risks materialize and affect their performance obligations to us, our financial results may be adversely affected.

In addition, we, our third-party manufacturers and our corporate partners may only be able to produce some of our products at one or a limited number of facilities and, therefore, have limited manufacturing capacity for certain products. For example, earlier in 2012, due to unexpected delays both in qualifying two new external sites and with expanding Cayston manufacturing in San Dimas, we were unable to supply enough Cayston to fulfill our projected demand. During February through September 2012, we suspended access for patients with new prescriptions for Cayston subject to certain exceptions where specific medical need exists. As a result of our inability to manufacture sufficient Cayston to meet demand, the amount of revenues we received from the sale of Cayston was reduced.

Our manufacturing operations are subject to routine inspections by regulatory agencies. For example, in January and February 2010, the FDA conducted a routine inspection of our San Dimas manufacturing facility, where we exclusively manufacture Cayston and AmBisome and fill and finish Macugen. At the conclusion of that inspection, the FDA issued Form 483 Inspectional Observations stating concerns over: the maintenance of aseptic processing conditions in the manufacturing suite for our AmBisome product; environmental maintenance issues in the San Dimas warehousing facility; batch sampling; and the timeliness of completion of annual product quality reports. On September 24, 2010, our San Dimas manufacturing facility received a Warning Letter from the FDA further detailing the FDA's concerns over the AmBisome manufacturing environment, including control systems and monitoring, procedures to prevent microbiological contamination and preventative cleaning and equipment maintenance. Referencing certain Viread lots, the letter also stated concerns connected with quality procedures, controls and investigation procedures, and a generalized concern over the effectiveness of the San Dimas quality unit in carrying out its responsibilities. In November and December 2010, the FDA re-inspected the San Dimas facility. The re-inspection closed with no additional Form 483 observations. In August 2011, the FDA notified us that we resolved all issues raised by the FDA in its Warning Letter.

Our ability to successfully manufacture and commercialize Cayston will depend upon our ability to manufacture in a multi-product facility.

Aztreonam, the active pharmaceutical ingredient in Cayston, is a mono-bactam Gram-negative antibiotic. We manufacture Cayston by ourselves in San Dimas, California, or through third parties, in multi-product manufacturing facilities. Historically, the FDA has permitted the manufacture of mono-bactams in multi-product manufacturing facilities; however, there can be no assurance that the FDA will continue to allow this practice. We do not currently have a single-product facility that can be dedicated to the manufacture of Cayston nor have we engaged a contract manufacturer with a single-product facility for Cayston. If the FDA prohibits the manufacture of mono-bactam antibiotics, like aztreonam, in multi-product manufacturing facilities in the future, we may not be able to procure a single-product manufacturing facility in a timely manner, which would adversely affect our commercial supplies of Cayston and our anticipated financial results attributable to such product.

We may not be able to obtain materials or supplies necessary to conduct clinical trials or to manufacture and sell our products, which would limit our ability to generate revenues.

We need access to certain supplies and products to conduct our clinical trials and to manufacture our products. In light of the global economic downturn, we have had increased difficulty in purchasing certain of the raw materials used in our manufacturing process. If we are unable to purchase sufficient quantities of these materials or find suitable alternate materials in a timely manner, our development efforts for our product candidates may be delayed or our ability to manufacture our products would be limited, which would limit our ability to generate revenues.

Suppliers of key components and materials must be named in an NDA filed with the FDA, EMA or other regulatory authority for any product candidate for which we are seeking marketing approval, and significant delays can occur if the qualification of a new supplier is required. Even after a manufacturer is qualified by the regulatory authority, the manufacturer must continue to expend time, money and effort in the area of production and quality control to ensure full compliance with GMP. Manufacturers are subject to regular, periodic inspections by the regulatory authorities following initial approval. If, as a result of these inspections, a regulatory authority determines that the equipment, facilities, laboratories or processes do not comply with applicable regulations and conditions of product approval, the regulatory authority may suspend the manufacturing operations. If the manufacturing operations of any of the single suppliers for our products are suspended, we may be unable to generate sufficient quantities of commercial or clinical supplies of product to meet market demand, which would in turn decrease our revenues and harm our business. In addition, if delivery of material from our suppliers were interrupted for any reason, we may be unable to ship certain of our products for commercial supply or to supply our products in development for clinical trials. In addition, some of our products and the materials that we utilize in our operations are made at only one facility. For example, we manufacture AmBisome and fill and finish Macugen exclusively at our facilities in San Dimas, California. In the event of a disaster, including an earthquake, equipment failure or other difficulty, we may be unable to replace this manufacturing capacity in a timely manner and may be unable to manufacture AmBisome and Macugen to meet market needs.

Cayston is dependent on two different third-party single-source suppliers. First, aztreonam, the active pharmaceutical ingredient in Cayston, is manufactured by a single supplier at a single site. Second, it is administered to the lungs of patients through a device that is made by a single supplier at a single site. Disruptions or delays with any of these single suppliers could adversely affect our ability to supply Cayston, and we cannot be sure that alternative suppliers can be identified in a timely manner, or at all. See the Risk Factor entitled “Our ability to successfully manufacture and commercialize Cayston will depend upon our ability to manufacture in a multi-product facility.”

In addition, we depend on a single supplier for high-quality cholesterol, which is used in the manufacture of AmBisome. We also rely on a single source for the active pharmaceutical ingredient of Hepsera, Letairis and Vistide and for the tableting of Letairis. Astellas US LLC, which markets Lexiscan in the United States, is responsible for the commercial manufacture and supply of product in the United States and is dependent on a single supplier for the active pharmaceutical ingredient of Lexiscan. Problems with any of the single suppliers we depend on may negatively impact our development and commercialization efforts.

A significant portion of the raw materials and intermediates used to manufacture our HIV products (Atripla, Truvada, Viread, Complera/Eviplera, Stribild and Emtriva) are supplied by Chinese-based companies. As a result, an international trade dispute between China and the United States or any other actions by the Chinese government that would limit or prevent Chinese companies from supplying these materials would adversely affect our ability to manufacture and supply our HIV products to meet market needs and have a material and adverse effect on our operating results.

We face credit risks from our Southern European customers that may adversely affect our results of operations.

Our European product sales to government-owned or supported customers in Southern Europe, specifically Greece, Italy, Portugal and Spain have historically been and continue to be subject to significant payment delays due to government funding and reimbursement practices. This has resulted and may continue to result in days sales outstanding being significantly higher in these countries due to the average length of time that accounts receivable remain outstanding.

As of September 30, 2012, our accounts receivable in these countries totaled approximately $826.8 million, of which $314.9 million were past due greater than 120 days and $84.8 million were past due greater than 365 days as follows (in thousands):

	September 30, 2012	
	Greater than 120 days past due	Greater than 365 days past due
Portugal	$93,912	$23,824
Italy	105,818	49,217
Spain	92,249	7,804
Greece	22,888	3,965
Total	$314,867	$84,810

As a result of the fiscal and debt crises in these countries, the number of days our invoices are past due has continued to increase in line with that being experienced by other pharmaceutical companies that are also selling directly to hospitals. Historically, receivable balances with certain publicly-owned hospitals accumulate over a period of time and are then subsequently settled as large lump sum payments. If significant changes were to occur in the reimbursement practices of these European governments or if government funding becomes unavailable, we may not be able to collect on amounts due to us from these customers and our results of operations would be adversely affected.

In 2011, the Greek government settled substantially all of its outstanding receivables subject to the bond settlement with zero-coupon bonds that traded at a discount to face value. In March 2012, the Greek government restructured its sovereign debt which impacted all holders of Greek bonds. As a result, we recorded a $40.1 million loss. In June 2012, we received payment on $460.6 million accounts receivable from customers in Spain that were past due six months or more.

Our revenues and gross margin could be reduced by imports from countries where our products are available at lower prices.

Prices for our products are based on local market economics and competition and sometimes differ from country to country. Our sales in countries with relatively higher prices may be reduced if products can be imported into those or other countries from lower price markets. There have been cases in which other pharmaceutical products were sold at steeply discounted prices in the developing world and then re-exported to European countries where they could be re-sold at much higher prices. If this happens with our products, particularly Truvada and Viread, which we have agreed to make available at substantially reduced prices to 134 countries participating in our Gilead Access Program, or Atripla, which Merck distributes at substantially reduced prices to HIV infected patients in developing countries under our 2006 agreement, our revenues would be adversely affected. In addition, we have established partnerships with thirteen Indian generic manufacturers to distribute high-quality, low-cost generic versions of tenofovir disoproxil fumarate to 112 developing world countries, including India. If generic versions of our medications under these licenses are then re-exported to the United States, Europe or other markets outside of these 112 countries, our revenues would be adversely affected.

In addition, purchases of our products in countries where our selling prices are relatively low for resale in countries in which our selling prices are relatively high may adversely impact our revenues and gross margin and may cause our sales to fluctuate from quarter to quarter. For example, in the European Union, we are required to permit products purchased in one country to be sold in another country. Purchases of our products in countries where our selling prices are relatively low for resale in countries in which our selling prices are relatively high affect the inventory level held by our wholesalers and can cause the relative sales levels in the various countries to fluctuate from quarter to quarter and not reflect the actual consumer demand in any given quarter. These quarterly fluctuations may impact our earnings, which could adversely affect our stock price and harm our business.

Expensive litigation and government investigations have reduced and may continue to reduce our earnings.

We are involved in a number of litigation, investigation and other dispute-related matters that require us to expend substantial internal and financial resources. We expect these matters will continue to require a high level of internal and financial resources for the foreseeable future. These matters have reduced and will continue to reduce our earnings. Please see a description of our Department of Justice investigation; Interference and litigation proceedings with Idenix; ANDA litigation with generic manufacturers; and contract arbitration with Jeremy Clark in "Legal Proceedings" beginning on page 39.

The outcome of the lawsuits above, or any other lawsuits that may be brought against us, the investigation or any other investigations that may be initiated, are inherently uncertain, and adverse developments or outcomes can result in significant expenses, monetary damages, penalties or injunctive relief against us that could significantly reduce our earnings and cash flows and harm our business.

In some countries, we may be required to grant compulsory licenses for our products or face generic competition for our products.

In a number of developing countries, government officials and other interested groups have suggested that pharmaceutical companies should make drugs for HIV infection available at low cost. Alternatively, governments in those developing countries could require that we grant compulsory licenses to allow competitors to manufacture and sell their own versions of our products, thereby reducing our product sales. For example, in the past, certain offices of the government of Brazil have expressed concern over the affordability of our HIV products and declared that they were considering issuing compulsory licenses to permit the manufacture of otherwise patented products for HIV infection, including Viread. In July 2009, the Brazilian patent authority rejected our patent application for tenofovir disoproxil fumarate, the active pharmaceutical ingredient in Viread. This was the highest level of appeal available to us within the Brazilian patent authority. Because we do not currently have a patent in Brazil, the Brazilian government now purchases its supply of tenofovir disoproxil fumarate from generic manufacturers.

In addition, concerns over the cost and availability of Tamiflu related to a potential avian flu pandemic and H1N1 influenza generated international discussions over compulsory licensing of our Tamiflu patents. For example, the Canadian government considered allowing Canadian manufacturers to manufacture and export the active ingredient in Tamiflu to eligible developing and least developed countries under Canada's Access to Medicines Regime. Furthermore, Roche issued voluntary licenses to permit third-party manufacturing of Tamiflu. For example, Roche granted a sublicense to Shanghai Pharmaceutical (Group) Co., Ltd. for China and a sublicense to India's Hetero Drugs Limited for India and certain developing countries. Should one or more compulsory licenses be issued permitting generic manufacturing to override our Tamiflu patents, or should Roche issue additional voluntary licenses to permit third-party manufacturing of Tamiflu, those developments could reduce royalties we receive from Roche's sales of Tamiflu. Certain countries do not permit enforcement of our patents, and third-party manufacturers are able to sell generic versions of our products in those countries. Compulsory licenses or sales of generic versions of our products could significantly reduce our sales and adversely affect our results of operations, particularly if generic versions of our products are imported into territories where we have existing commercial sales.

Changes in royalty revenue disproportionately affect our pre-tax income, earnings per share and gross margins.

A portion of our revenues is derived from royalty revenues recognized from collaboration agreements with third parties. Royalty revenues impact our pre-tax income, earnings per share and gross margins disproportionately more than their contributions to our revenues. Any increase or decrease to our royalty revenue could be material and could significantly impact our operating results. For example, we recognized $75.5 million in royalty revenue for the year ended December 31, 2011 related to royalties received from sales of Tamiflu by Roche. Although such royalty revenue represented approximately 1% of our total revenues in 2011, it represented approximately 2% of our pre-tax income during the period. Roche's Tamiflu sales have unpredictable variability due to their strong relationship with global pandemic planning efforts. Tamiflu royalties increased sharply in 2009 and the first quarter of 2010 primarily as a result of pandemic planning initiatives worldwide. Tamiflu royalties since the second quarter of 2010 have decreased due to declining pandemic planning initiatives worldwide.

We may face significant liability resulting from our products that may not be covered by insurance and successful claims could materially reduce our earnings.

The testing, manufacturing, marketing and use of our commercial products, as well as product candidates in development, involve substantial risk of product liability claims. These claims may be made directly by consumers, healthcare providers, pharmaceutical companies or others. In recent years, coverage and availability of cost-effective product liability insurance has decreased, so we may be unable to maintain sufficient coverage for product liabilities that may arise. In addition, the cost to defend lawsuits or pay damages for product liability claims may exceed our coverage. If we are unable to maintain adequate coverage or if claims exceed our coverage, our financial condition and our ability to clinically test our product candidates and market our products will be adversely impacted. In addition, negative publicity associated with any claims, regardless of their merit, may decrease the future demand for our products and impair our financial condition.

Business disruptions from natural or man-made disasters may harm our future revenues.

Our worldwide operations could be subject to business interruptions stemming from natural or man-made disasters for which we may be self-insured. Our corporate headquarters and Fremont locations, which together house a majority of our research and development activities, and our San Dimas and Oceanside manufacturing facilities are located in California, a seismically active region. As we do not carry earthquake insurance and significant recovery time could be required to resume operations, our financial condition and operating results could be materially adversely affected in the event of a major earthquake.

Changes in our effective income tax rate could reduce our earnings.

Various factors may have favorable or unfavorable effects on our income tax rate. These factors include, but are not limited to, interpretations of existing tax laws, changes in tax laws and rates, our portion of the non-deductible pharmaceutical excise tax, the accounting for stock options and other share-based payments, mergers and acquisitions, future levels of R&D spending, changes in accounting standards, changes in the mix of earnings in the various tax jurisdictions in which we operate, changes in overall levels of pre-tax earnings and resolution of federal, state and foreign income tax audits. The impact on our income tax provision resulting from the above mentioned factors may be significant and could have a negative impact on our net income.

Our income tax returns are audited by federal, state and foreign tax authorities. We are currently under examination by the Internal Revenue Service for the 2008 and 2009 tax years and by various state and foreign jurisdictions. There are differing interpretations of tax laws and regulations, and as a result, significant disputes may arise with these tax authorities involving issues of the timing and amount of deductions and allocations of income among various tax jurisdictions. Resolution of one or more of these exposures in any reporting period could have a material impact on the results of operations for that period.

If we fail to attract and retain highly qualified personnel, we may be unable to successfully develop new product candidates, conduct our clinical trials and commercialize our product candidates.

Our future success will depend in large part on our continued ability to attract and retain highly qualified scientific, technical and management personnel, as well as personnel with expertise in clinical testing, governmental regulation and commercialization. We face competition for personnel from other companies, universities, public and private research institutions, government entities and other organizations. Competition for qualified personnel in the biopharmaceutical field is intense, and there is a limited pool of qualified potential employees to recruit. We may not be able to attract and retain quality personnel on acceptable terms. If we are unsuccessful in our recruitment and retention efforts, our business may be harmed.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

During the third quarter of 2012, we made $205.2 million in purchases under our January 2011, three-year, $5.00 billion stock repurchase program. As of September 30, 2012, we had repurchased $869.9 million of our common stock under the January 2011 stock repurchase program with a remaining authorized amount of $4.13 billion available for repurchases under this program.

The table below summarizes our stock repurchase activity for the three months ended September 30, 2012 (in thousands, except per share amounts):

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program [1]	Maximum Fair Value of Shares that May Yet Be Purchased Under the Program [1]
July 1 – July 31, 2012	130	$ 49.43	100	$4,330,086
August 1 – August 31, 2012	2,018	$ 51.05	1,946	$4,219,184
September 1 – September 30, 2012	1,422	$ 49.93	1,414	$4,130,086
Total	3,570 [2]	$ 50.55	3,460 [2]	

(1) In January 2011, we announced that our Board authorized a $5.00 billion stock repurchase program, which expires in January 2014.

(2) The difference between the total number of shares purchased and the total number of shares purchased as part of publicly announced programs is due to shares of common stock withheld by us from employee restricted stock awards in order to satisfy our applicable tax withholding obligations.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibit Footnote	Exhibit Number	Description of Document
√(1)	2.1	Agreement and Plan of Merger among Registrant, Apex Merger Sub, Inc. and CV Therapeutics, Inc., dated as of March 12, 2009
†(2)	2.5	Agreement and Plan of Merger among Registrant, Merger Sub and Pharmasset, Inc., dated as of November 21, 2011
(3)	3.1	Restated Certificate of Incorporation of Registrant, as amended through May 12, 2011
(3)	3.2	Amended and Restated Bylaws of Registrant, as amended and restated on May 12, 2011
	4.1	Reference is made to Exhibit 3.1 and Exhibit 3.2
(4)	4.2	Indenture related to the Convertible Senior Notes due 2013 (2013 Notes), between Registrant and Wells Fargo Bank, National Association, as trustee (including form of 0.625% Convertible Senior Note due 2013), dated April 25, 2006
(5)	4.3	Indenture related to the Convertible Senior Notes due 2014 (2014 Notes), between Registrant and Wells Fargo Bank, National Association, as trustee (including form of 1.00% Convertible Senior Note due 2014), dated July 30, 2010
(5)	4.4	Indenture related to the Convertible Senior Notes due 2016 (2016 Notes), between Registrant and Wells Fargo Bank, National Association, as trustee (including form of 1.625% Convertible Senior Note due 2016), dated July 30, 2010
(6)	4.5	Indenture related to Senior Notes, dated as of March 30, 2011, between Registrant and Wells Fargo, National Association, as Trustee
(6)	4.6	First Supplemental Indenture related to Senior Notes, dated as of March 30, 2011, between Registrant and Wells Fargo, National Association, as Trustee (including form of Senior Notes)
(7)	4.7	Second Supplemental Indenture related to Senior Notes, dated as of December 13, 2011, between Registrant and Wells Fargo, National Association, as Trustee (including Form of 2014 Note, Form of 2016 Note, Form of 2021 Note, Form of 2041 Note)
(8)	10.1	Confirmation of OTC Convertible Note Hedge related to 2013 Notes, dated April 19, 2006, as amended and restated as of April 24, 2006, between Registrant and Bank of America, N.A.
(8)	10.2	Confirmation of OTC Warrant Transaction, dated April 19, 2006, as amended and restated as of April 24, 2006, between Registrant and Bank of America, N.A. for warrants expiring in 2013
(9)	10.3	Confirmation of OTC Convertible Note Hedge related to 2014 Notes, dated July 26, 2010, between Registrant and Goldman, Sachs & Co.
(9)	10.4	Confirmation of OTC Convertible Note Hedge related to 2014 Notes, dated July 26, 2010, between Registrant and JPMorgan Chase Bank, National Association

(9)	10.5	Confirmation of OTC Convertible Note Hedge related to 2016 Notes, dated July 26, 2010, between Registrant and Goldman, Sachs & Co.
(9)	10.6	Confirmation of OTC Convertible Note Hedge related to 2016 Notes, dated July 26, 2010, between Registrant and JPMorgan Chase Bank, National Association
(9)	10.7	Confirmation of OTC Warrant Transaction, dated July 26, 2010, between Registrant and Goldman, Sachs & Co. for warrants expiring in 2014
(9)	10.8	Confirmation of OTC Warrant Transaction, dated July 26, 2010, between Registrant and JPMorgan Chase Bank, National Association for warrants expiring in 2014
(9)	10.9	Confirmation of OTC Warrant Transaction, dated July 26, 2010, between Registrant and Goldman, Sachs & Co. for warrants expiring in 2016
(9)	10.10	Confirmation of OTC Warrant Transaction, dated July 26, 2010, between Registrant and JPMorgan Chase Bank, National Association for warrants expiring in 2016
(10)	10.11	Confirmation of OTC Additional Convertible Note Hedge related to 2014 Notes, dated August 5, 2010, between Registrant and Goldman, Sachs & Co.

Exhibit Footnote	Exhibit Number	Description of Document
(10)	10.12	Confirmation of OTC Additional Convertible Note Hedge related to 2014 Notes, dated August 5, 2010, between Registrant and JPMorgan Chase Bank, National Association
(10)	10.13	Confirmation of OTC Additional Convertible Note Hedge related to 2016 Notes, dated August 5, 2010, between Registrant and Goldman, Sachs & Co.
(10)	10.14	Confirmation of OTC Additional Convertible Note Hedge related to 2016 Notes, dated August 5, 2010, between Registrant and JPMorgan Chase Bank, National Association
(10)	10.15	Confirmation of OTC Additional Warrant Transaction, dated August 5, 2010, between Registrant and Goldman, Sachs & Co. for warrants expiring in 2014
(10)	10.16	Confirmation of OTC Additional Warrant Transaction, dated August 5, 2010, between Registrant and JPMorgan Chase Bank, National Association for warrants expiring in 2014
(10)	10.17	Confirmation of OTC Additional Warrant Transaction, dated August 5, 2010, between Registrant and Goldman, Sachs & Co. for warrants expiring in 2016
(10)	10.18	Confirmation of OTC Additional Warrant Transaction, dated August 5, 2010, between Registrant and JPMorgan Chase Bank, National Association for warrants expiring in 2016
(10)	10.19	Amendment to Confirmation of OTC Convertible Note Hedge related to 2014 Notes, dated August 30, 2010, between Registrant and Goldman, Sachs & Co.
(10)	10.20	Amendment to Confirmation of OTC Convertible Note Hedge related to 2014 Notes, dated August 30, 2010, between Registrant and JPMorgan Chase Bank, National Association
(10)	10.21	Amendment to Confirmation of OTC Convertible Note Hedge related to 2016 Notes, dated August 30, 2010, between Registrant and Goldman, Sachs & Co.
(10)	10.22	Amendment to Confirmation of OTC Convertible Note Hedge related to 2016 Notes, dated August 30, 2010, between Registrant and JPMorgan Chase Bank, National Association
(10)	10.23	Amendment to Confirmation of OTC Additional Convertible Note Hedge related to 2014 Notes, dated August 30, 2010, between Registrant and Goldman, Sachs & Co.
(10)	10.24	Amendment to Confirmation of OTC Additional Convertible Note Hedge related to 2014 Notes, dated August 30, 2010, between Registrant and JPMorgan Chase Bank, National Association
(10)	10.25	Amendment to Confirmation of OTC Additional Convertible Note Hedge related to 2016 Notes, dated August 30, 2010, between Registrant and Goldman, Sachs & Co.
(10)	10.26	Amendment to Confirmation of OTC Additional Convertible Note Hedge related to 2016 Notes, dated August 30, 2010, between Registrant and JPMorgan Chase Bank, National Association
(11)	10.27	

		5-Year Revolving Credit Facility Credit Agreement among Registrant and Gilead Biopharmaceutics Ireland Corporation, as Borrowers, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer, certain other lenders parties thereto, Barclays Capital, as Syndication Agent, and Goldman Sachs Bank USA, JPMorgan Chase Bank, N.A., Royal Bank of Canada and Wells Fargo Bank, N.A., as Co-Documentation Agents, dated as of January 12, 2012
(11)	10.28	Short-Term Revolving Credit Facility Credit Agreement, among Registrant and Gilead Biopharmaceutics Ireland Corporation, as Borrowers, Bank of America, N.A., as Administrative Agent, certain other lenders parties thereto, Barclays Capital, as Syndication Agent, and Goldman Sachs Bank USA, JPMorgan Chase Bank, N.A., Royal Bank of Canada and Wells Fargo Bank, N.A., as Co-Documentation Agents, dated as of January 12, 2012
(11)	10.29	Term Loan Facility Credit Agreement, among Registrant, as Borrower, Bank of America, N.A., certain other lenders parties thereto, Barclays Capital, as Syndication Agent, and Goldman Sachs Bank USA, JPMorgan Chase Bank, N.A., Royal Bank of Canada and Wells Fargo Bank, N.A., as Co-Documentation Agents, dated as of January 12, 2012
(11)	10.30	Parent Guaranty Agreement (5-Year Revolving Credit Facility), dated as of January 12, 2012, by Registrant
(11)	10.31	Parent Guaranty Agreement (Short-Term Revolving Credit Facility), dated as of January 12, 2012, by Registrant

Exhibit Footnote	Exhibit Number	Description of Document
*(12)	10.32	Gilead Sciences, Inc. 1991 Stock Option Plan, as amended through January 29, 2003
*(13)	10.33	Form of option agreements used under the 1991 Stock Option Plan
*(12)	10.34	Gilead Sciences, Inc. 1995 Non-Employee Directors' Stock Option Plan, as amended through January 30, 2002
*(14)	10.35	Form of option agreement used under the Gilead Sciences, Inc. 1995 Non-Employee Directors' Stock Option Plan
*(15)	10.36	Gilead Sciences, Inc. 2004 Equity Incentive Plan, as amended through May 6, 2009
*(16)	10.37	Form of employee stock option agreement used under 2004 Equity Incentive Plan (for grants prior to February 2008)
*(17)	10.38	Form of employee stock option agreement used under 2004 Equity Incentive Plan (for grants made February 2008 through April 2009)
*(18)	10.39	Form of employee stock option agreement used under 2004 Equity Incentive Plan (for grants commencing in May 2009)
*(19)	10.40	Form of employee stock option agreement used under 2004 Equity Incentive Plan (for grants commencing in February 2010)
*(20)	10.41	Form of employee stock option agreement used under 2004 Equity Incentive Plan (for 2011 and subsequent year grants)
*(17)	10.42	Form of non-employee director stock option agreement used under 2004 Equity Incentive Plan (for grants prior to 2008)
*(17)	10.43	Form of non-employee director option agreement used under 2004 Equity Incentive Plan (for initial grants made in 2008)
*(17)	10.44	Form of non-employee director option agreement used under 2004 Equity Incentive Plan (for annual grants made in May 2008)
*(18)	10.45	Form of non-employee director option agreement used under 2004 Equity Incentive Plan (for annual grants commencing in May 2009)
*(21)	10.46	Form of restricted stock unit issuance agreement used under 2004 Equity Incentive Plan (for annual grants to non-employee directors commencing in May 2012)
*(18)	10.47	Form of restricted stock award agreement used under 2004 Equity Incentive Plan (for annual grants to certain non-employee directors prior to May 2012)
*(18)	10.48	Form of performance share award agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers made in 2009)

*(19) 10.49	Form of performance share award agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers made in 2010)
*(20) 10.50	Form of performance share award agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers made in 2011)
*(22) 10.51	Form of performance share award agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers made in 2012)
*(23) 10.52	Form of restricted stock unit issuance agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers made prior to May 2009)
*(18) 10.53	Form of restricted stock unit issuance agreement used under the 2004 Equity Incentive Plan (for grants to certain executive officers commencing in May 2009)
*(24) 10.54	Form of restricted stock unit issuance agreement used under the 2004 Equity Incentive Plan (service-based vesting for certain executive officers commencing in November 2009)
*(20) 10.55	Form of restricted stock unit issuance agreement used under the 2004 Equity Incentive Plan (service-based vesting for certain executive officers commencing in 2011)

Exhibit Footnote	Exhibit Number	Description of Document
*(19)	10.56	Gilead Sciences, Inc. Employee Stock Purchase Plan, amended and restated on November 3, 2009
*(25)	10.57	Gilead Sciences, Inc. International Employee Stock Purchase Plan, adopted November 3, 2009
*(26)	10.58	Gilead Sciences, Inc. Deferred Compensation Plan-Basic Plan Document
*(26)	10.59	Gilead Sciences, Inc. Deferred Compensation Plan-Adoption Agreement
*(26)	10.60	Addendum to the Gilead Sciences, Inc. Deferred Compensation Plan
*(27)	10.61	Gilead Sciences, Inc. 2005 Deferred Compensation Plan, as amended and restated on October 23, 2008
*(22)	10.62	Gilead Sciences, Inc. Severance Plan, as amended on January 26, 2012
*(16)	10.63	Gilead Sciences, Inc. Corporate Bonus Plan
*(3)	10.64	Amended and Restated Gilead Sciences, Inc. Code Section 162(m) Bonus Plan
*(28)	10.65	2012 Base Salaries for the Named Executive Officers
*(29)	10.66	Offer Letter dated April 16, 2008 between Registrant and Robin Washington
*(13)	10.67	Form of Indemnity Agreement entered into between Registrant and its directors and executive officers
*(13)	10.68	Form of Employee Proprietary Information and Invention Agreement entered into between Registrant and certain of its officers and key employees
*(19)	10.69	Form of Employee Proprietary Information and Invention Agreement entered into between Registrant and certain of its officers and key employees (revised in September 2006)
+(30)	10.70	Amended and Restated Collaboration Agreement by and among Registrant, Gilead Holdings, LLC, Bristol-Myers Squibb Company, E.R. Squibb & Sons, L.L.C., and Bristol-Myers Squibb & Gilead Sciences, LLC, dated September 28, 2006
(17)	10.71	Commercialization Agreement by and between Gilead Sciences Limited and Bristol-Myers Squibb Company, dated December 10, 2007
+(31)	10.72	Amendment Agreement, dated October 25, 1993, between Registrant, the Institute of Organic Chemistry and Biochemistry (IOCB) and Rega Stichting v.z.w. (REGA), together with the following exhibits: the License Agreement, dated December 15, 1991, between Registrant, IOCB and REGA (the 1991

2015 2014

License Agreement), the License Agreement, dated October 15, 1992, between Registrant, IOCB and REGA (the October 1992 License Agreement) and the License Agreement, dated December 1, 1992, ottom" STYLE="BORDER-TOP:1px solid #000000; BORDER-BOTTOM:1px solid #000000">At December 31,

(millions)

LIABILITIES AND EQUITY			
Current Liabilities			
Securities due within one year	$	**400**	$
Short-term debt		**391**	
Accounts payable		**201**	247
Payables to affiliates		**22**	41
Affiliated current borrowings		**95**	384
Accrued interest, payroll and taxes(1)		**183**	194
Regulatory liabilities		**55**	75
Other(1)		**128**	97
Total current liabilities		**1,475**	1,038
Long-Term Debt		**2,892**	2,594
Deferred Credits and Other Liabilities			
Deferred income taxes and investment tax credits		**2,214**	2,158
Regulatory liabilities		**201**	192
Other(1)		**231**	300
Total deferred credits and other liabilities		**2,646**	2,650
Total liabilities		**7,013**	6,282
Commitments and Contingencies (see Note 22)			
Equity			
Membership interests		**3,417**	3,652
Accumulated other comprehensive loss		**(99)**	(86)
Total equity		**3,318**	3,566
Total liabilities and equity	$	**10,331**	$ 9,848

(1) See Note 24 for amounts attributable to related parties.
The accompanying notes are an integral part of Dominion Gas   Consolidated Financial Statements.

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Dominion Gas Holdings, LLC

Consolidated Statements of Equity

(millions)	Membership Interests	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2012	$ 3,416	$ (140)	$ 3,276
Net income	461		461
Equity contribution from parent	6		6
Distributions	(398)		(398)
Other comprehensive income, net of tax		82	82
Balance at December 31, 2013	3,485	(58)	3,427
Net income	512		512
Equity contribution from parent	1		1
Distributions	(346)		(346)
Other comprehensive loss, net of tax		(28)	(28)
Balance at December 31, 2014	3,652	(86)	3,566
Net income	**457**		**457**
Distributions	**(692)**		**(692)**
Other comprehensive loss, net of tax		**(13)**	**(13)**
Balance at December 31, 2015	**$ 3,417**	**$ (99)**	**$ 3,318**

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

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Dominion Gas Holdings, LLC

Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	**2015**	2014	2013
Operating Activities			
Net income	**$ 457**	$ 512	$ 461
Adjustments to reconcile net income to net cash provided by operating activities:			
Gains on sales of assets	**(123)**	(124)	(122)
Depreciation and amortization	**217**	197	188
Deferred income taxes and investment tax credits, net	**163**	216	102
Other adjustments	**16**	2	(3)
Changes in:			
Accounts receivable	**115**	(42)	(17)
Affiliated receivables	**(86)**	(1)	2
Inventories	**(13)**	(2)	
Prepayments	**99**	(99)	13
Accounts payable	**(51)**	(35)	62
Payables to affiliates	**(19)**	(4)	8
Accrued interest, payroll and taxes	**(11)**	(15)	48
Other operating assets and liabilities	**(136)**	(134)	(44)
Net cash provided by operating activities	**628**	471	698
Investing Activities			
Plant construction and other property additions	**(795)**	(719)	(650)
Proceeds from sale of assets to an affiliate		47	113
Proceeds from Blue Racer		1	78
Proceeds from assignments of shale development rights	**79**	60	18
Advances to affiliate, net			(5)
Other	**(11)**	(5)	(14)
Net cash used in investing activities	**(727)**	(616)	(460)
Financing Activities			
Issuance of short-term debt, net	**391**		
Repayment of affiliated current borrowings, net	**(289)**	(892)	(545)
Repayment and acquisition of affiliated long-term debt			(569)
Issuance of long-term debt	**700**	1,400	1,200
Distribution payments to parent	**(692)**	(346)	(318)
Other	**(7)**	(16)	(10)
Net cash provided by (used in) financing activities	**103**	146	(242)
Increase (decrease) in cash and cash equivalents	**4**	1	(4)
Cash and cash equivalents at beginning of year	**9**	8	12
Cash and cash equivalents at end of year	**$ 13**	$ 9	$ 8
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 70**	$ 23	$ 31
Income taxes	**98**	266	148
Significant noncash investing and financing activities:			
Accrued capital expenditures	**57**	35	42
Extinguishment of affiliated long-term debt in exchange for assets sold to affiliate		67	
Distribution of non-cash asset (account receivable) to parent			80
Proceeds from sale of assets to affiliate not yet received			30

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

Combined Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Dominion, headquartered in Richmond, Virginia, is one of the nation s largest producers and transporters of energy. Dominion s operations are conducted through various subsidiaries, including Virginia Power and Dominion Gas. Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. Virginia Power is a member of PJM, an RTO, and its electric transmission facilities are integrated into the PJM wholesale electricity markets. All of Virginia Power s stock is owned by Dominion. Dominion Gas is a holding company that conducts business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. All of Dominion Gas membership interests are held by Dominion.

Dominion s operations also include an LNG import, transport and storage facility in Maryland, a preferred equity interest in which was contributed to Dominion Midstream in 2014, an equity investment in Atlantic Coast Pipeline and regulated gas transportation and distribution operations in West Virginia. Dominion s nonregulated operations include merchant generation, energy marketing and price risk management activities, retail energy marketing operations and an equity investment in Blue Racer.

In October 2014, Dominion Midstream launched its initial public offering of 20,125,000 common units representing limited partner interests at a price of $21 per unit, which included an over-allotment option to purchase an additional 2,625,000 common units at the initial offering price, which was exercised in full by the underwriters. Dominion received $392 million in net proceeds from the sale of the units, after deducting underwriting discounts, structuring fees and estimated offering expenses. At December 31, 2015, Dominion owns the general partner and 64.1% of the limited partner interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DCG and a 25.93% noncontrolling partnership interest in Iroquois. The public s ownership interest in Dominion Midstream is reflected as non-controlling interest in Dominion s Consolidated Financial Statements.

Dominion manages its daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. Dominion also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt) and the net impact of operations that are discontinued, which is discussed in Notes 3 and 25. In addition, Corporate and Other includes specific items attributable to Dominion s operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

Virginia Power manages its daily operations through two primary operating segments: DVP and Dominion Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

Dominion Gas manages its daily operations through one primary operating segment: Dominion Energy. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment s performance and the effect of certain items recorded at Dominion Gas as a result of the recognition of Dominion s basis in the net assets contributed.

See Note 25 for further discussion of the Companies operating segments.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

The Companies make certain estimates and assumptions in preparing their Consolidated Financial Statements in accordance with 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, expenses and cash flows for the periods presented. Actual results may differ from those estimates.

The Companies Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of their respective majority-owned subsidiaries and non-wholly-owned entities in which they have a controlling financial interest. For certain partnership structures, income is allocated based on the liquidation value of the underlying contractual arrangements. SunEdison s ownership interest in Four Brothers and Three Cedars, as well as Terra Nova Renewable Partners 33% interest in certain of Dominion s merchant solar projects, is reflected as noncontrolling interest in Dominion s Consolidated Financial Statements. See Note 3 for further information on transactions with SunEdison.

The Companies report certain contracts, instruments and investments at fair value. See Note 6 for further information on fair value measurements.

Dominion maintains pension and other postretirement benefit plans. Virginia Power and Dominion Gas participate in certain of these plans. See Note 21 for further information on these plans.

Certain amounts in the 2014 and 2013 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2015 presentation for comparative purposes. The reclassifications did not affect the Companies net income, total assets, liabilities, equity or cash flows.

Amounts disclosed for Dominion are inclusive of Virginia Power and/or Dominion Gas, where applicable.

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. Dominion and Virginia Power collect sales, consumption and consumer utility taxes and Dominion Gas collects sales taxes; however, these amounts are excluded from revenue. Dominion s customer receivables at December 31, 2015 and 2014 included $462 million and $564 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity and natural gas delivered but not yet billed to its utility

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customers. Virginia Power s customer receivables at December 31, 2015 and 2014 included $333 million and $407 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to its customers. Dominion Gas customer receivables at December 31, 2015 and 2014 included $98 million and $127 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its customers.

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

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Nonregulated electric sales** consist primarily of sales of electricity at market-based rates and contracted fixed rates, and associated derivative activity;
- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue and associated derivative activity;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of gathering, transmission, distribution and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers; and
- **Other revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity. Other revenue also includes miscellaneous service revenue from electric and gas distribution operations, and gas processing and handling revenue.

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

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric distribution operations and miscellaneous revenue from generation operations, including sales of capacity and other commodities.

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

- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices and sales of gas purchased from third parties. Revenue from sales of gas production is recognized based on actual volumes of gas sold to purchasers and is reported net of royalties;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of gathering, transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers;
- **NGL revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity; and
- **Other revenue** consists primarily of miscellaneous service revenue, gas processing and handling revenue.

Electric Fuel, Purchased Energy and Purchased Gas-Deferred Costs

Where permitted by regulatory authorities, the differences between Dominion s and Virginia Power s actual electric fuel and purchased energy expenses and Dominion s and Dominion Gas 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 in excess of current period fuel expenses is recognized as a regulatory liability.

Of the cost of fuel used in electric generation and energy purchases to serve utility customers, approximately 84% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Virtually all of Dominion Gas , Cove Point s and Hope s natural gas purchases are either subject to deferral accounting or are recovered from the customer in the same accounting period as the sale.

Income Taxes

A consolidated federal income tax return is filed for Dominion and its subsidiaries, including Virginia Power and Dominion Gas subsidiaries. In addition, where applicable, combined income tax returns for Dominion and its subsidiaries are filed in various states; otherwise, separate state income tax returns are filed.

Although Dominion Gas is disregarded for income tax purposes, a provision for income taxes is recognized to reflect the inclusion of its business activities in the tax returns of its parent, Dominion. Virginia Power and Dominion Gas participate in intercompany tax sharing agreements with Dominion and its subsidiaries. Current income taxes are based on taxable income or loss and credits determined on a separate company basis.

Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

Accounting for income taxes involves an asset and liability approach. 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. Accordingly, deferred taxes are recognized for the future consequences of different treatments used for the reporting of transactions in financial accounting and income tax returns. The Companies 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. Where the treatment of temporary differences is different for rate-regulated operations, a regulatory asset is recognized if it is probable that future revenues will be

Combined Notes to Consolidated Financial Statements, Continued

provided for the payment of deferred tax liabilities.

The Companies recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If it is not more-likely-than-not that a tax position, or some portion thereof, will be sustained, the related tax benefits are not recognized in the financial statements. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in income taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities, noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities on the Consolidated Balance Sheets and current payables are included in accrued interest, payroll and taxes on the Consolidated Balance Sheets.

The Companies recognize interest on underpayments and overpayments of income taxes in interest expense and other income, respectively. Penalties are also recognized in other income.

Dominion s, Virginia Power s and Dominion Gas interest and penalties were immaterial in 2015, 2014 and 2013.

At December 31, 2015, Virginia Power s Consolidated Balance Sheet included a $296 million affiliated receivable, representing current year excess federal income tax payments expected to be refunded, $9 million of federal income taxes payable for prior years, less than $1 million of state income taxes payable, $10 million of state income taxes receivable, $14 million of noncurrent state income taxes receivable and $2 million of noncurrent state income taxes payable.

At December 31, 2014, Virginia Power s Consolidated Balance Sheet included $225 million of federal and state income taxes receivable, $13 million of noncurrent state income taxes receivable and $38 million of noncurrent federal and state income taxes payable. In March 2015, Virginia Power received a $229 million refund of its 2014 federal income tax payments.

At December 31, 2015, Dominion Gas Consolidated Balance Sheet included $91 million of affiliated receivables, representing current year excess federal income tax payments expected to be refunded and the benefit of utilizing a subsidiary s tax loss to offset taxable income in Dominion s consolidated tax return to be filed in 2016, less than $1 million of state income taxes payable, $4 million of state income taxes receivable and $22 million of noncurrent state income taxes payable.

At December 31, 2014, Dominion Gas Consolidated Balance Sheet included $96 million of federal and state income taxes receivable, $14 million of state income taxes payable, $7 million of noncurrent state income taxes payable and $20 million noncurrent state income taxes receivable. In March 2015, Dominion Gas received a $93 million refund of its 2014 federal income tax payments.

Investment tax credits are recognized by nonregulated operations in the year qualifying property is placed in service. For regulated operations, investment tax credits are deferred and amortized over the service lives of the properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. The following table illustrates the checks outstanding but not yet presented for payment and recorded in accounts payable for the Companies:

Year Ended December 31,	2015	2014
(millions)		
Dominion	**$ 27**	$ 42
Virginia Power	**11**	20
Dominion Gas	**7**	9

For purposes of the Consolidated Statements of Cash Flows, cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

Dominion and Virginia Power use derivative instruments such as futures, swaps, forwards, options and FTRs to manage the commodity and financial market risks of their business operations. Dominion Gas uses derivative instruments such as physical and financial forwards, futures and swaps to manage commodity price and interest rate risks.

All derivatives, except those for which an exception applies, are required to be reported in the 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.

The Companies do not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Dominion had margin assets of $16 million and $287 million associated with cash collateral at December 31, 2015 and 2014, respectively. Dominion s margin liabilities associated with cash collateral at December 31, 2015 were immaterial. Dominion had margin liabilities of $34 million associated with cash collateral at December 31, 2014. Virginia Power did not have any margin assets associated with cash collateral at December 31, 2015. Virginia Power had margin assets of $6 million associated with cash collateral at December 31 2014. Virginia Power did not have any margin liabilities associated with cash collateral at December 31, 2015 or 2014. Dominion Gas did not have any margin assets or liabilities related to cash collateral at December 31, 2015 or 2014. See Note 7 for further information about derivatives.

To manage price risk, Dominion and Virginia Power hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent Dominion and Virginia Power do not hold offsetting positions for such derivatives, they believe these instruments represent economic hedges that mitigate their exposure to fluctuations in commodity prices and interest rates. As part of Dominion s strategy to market energy and manage related risks, it formerly managed a portfolio of commodity-based financial derivative instruments held for trading purposes. Dominion used established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and used various derivative instruments to reduce risk by creating offsetting market positions. In the second quarter of 2013, Dominion commenced a repositioning of its producer services business. The repositioning was completed in the first quarter of 2014 and resulted in the termination of natural gas trading and certain energy marketing activities.

Statement of Income Presentation:

- **Derivatives Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue on a net basis.
- **Derivatives Not Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue, operating expenses or interest and related charges based on the nature of the underlying risk.

In Virginia Power s generation operations, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities for jurisdictions subject to cost-based rate regulation. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

Derivative Instruments Designated as Hedging Instruments

The Companies designate a portion of their derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the Companies 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. The Companies 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, the Companies may elect to exclude certain gains or losses on hedging instruments from the assessment 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. Hedge accounting is discontinued prospectively for derivatives that cease to be highly effective hedges. For derivative instruments that are accounted for as fair value hedges or cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges A majority of the Companies hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas, NGLs and other energy-related products. The Companies also use interest rate swaps to hedge their exposure to variable interest rates on long-term debt. For transactions in which the Companies

are hedging the variability of cash flows, changes in the fair value of the derivatives are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. Any derivative gains or losses reported in AOCI are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Dominion entered into interest rate derivative instruments to hedge its forecasted interest payments related to planned debt issuances in 2013 and 2014. These interest rate derivatives were designated by Dominion as cash flow hedges in 2012 and 2013, prior to the formation of Dominion Gas. For the purposes of the Dominion Gas financial statements, the derivative balances, AOCI balance, and any income statement impact related to these interest rate derivative instruments entered into by Dominion have been, and will continue to be, included in the Dominion Gas Consolidated Financial Statements as the forecasted interest payments related to the debt issuances now occur at Dominion Gas.

Fair Value Hedges Dominion also uses fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and commodity inventory. In addition, Dominion and Virginia Power have designated interest rate swaps as fair value hedges on certain fixed rate long-term debt to manage interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item s fair value. Derivative gains and losses from the hedged item are reclassified to earnings when the hedged item is included in earnings, or earlier, if the hedged item no longer qualifies for hedge accounting.

Hedge accounting is discontinued if the hedged item no longer qualifies for hedge accounting. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives. See Note 7 for further information on derivatives.

Property, Plant and Equipment

Property, plant and equipment is recorded at lower of original cost or fair value, if impaired. Capitalized costs include labor, materials and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is generally charged to expense as it is incurred.

In 2015, 2014 and 2013, Dominion capitalized interest costs and AFUDC to property, plant and equipment of $100 million, $80 million and $66 million, respectively. In 2015, 2014 and 2013, Virginia Power capitalized AFUDC to property, plant and equipment of $30 million, $39 million and $33 million, respectively. In 2015, 2014 and 2013, Dominion Gas capitalized AFUDC to property, plant and equipment of $1 million, $1 million and $5 million, respectively.

Under Virginia law, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset and is not capitalized to property, plant and equipment. In 2015, 2014 and 2013, Virginia Power recorded $19 million, $8 million and $32 million of AFUDC related to these projects, respectively.

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Combined Notes to Consolidated Financial Statements, Continued

For property subject to cost-of-service rate regulation, including Virginia Power electric distribution, electric transmission, and generation property, Dominion Gas natural gas distribution and transmission property, and for certain Dominion natural gas property, the undepreciated cost of such property, less salvage value, is generally charged to accumulated depreciation at retirement. Cost of removal collections from utility customers not representing AROs are recorded as regulatory liabilities. For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from plant-in-service when it becomes probable it will be abandoned.

For property that is not subject to cost-of-service rate regulation, including nonutility property, cost of removal not associated with AROs is charged to expense as incurred. The Companies also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property s net book value at the retirement date.

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

Year Ended December 31, (percent)	**2015**	2014	2013
Dominion			
Generation	**2.78**	2.66	2.71
Transmission	**2.42**	2.38	2.36
Distribution	**3.11**	3.12	3.13
Storage	**2.42**	2.39	2.43
Gas gathering and processing	**3.19**	2.81	2.39
General and other	**3.67**	3.62	3.82
Virginia Power			
Generation	**2.78**	2.66	2.71
Transmission	**2.33**	2.34	2.28
Distribution	**3.33**	3.34	3.33
General and other	**3.40**	3.29	3.51
Dominion Gas			
Transmission	**2.46**	2.40	2.43
Distribution	**2.45**	2.47	2.50
Storage	**2.44**	2.40	2.43
Gas gathering and processing	**3.20**	2.82	2.39
General and other	**4.72**	5.77	5.93

In 2013, Virginia Power revised its depreciation rates to reflect the results of a new depreciation study. This change resulted in an increase of $19 million ($12 million after-tax) in depreciation and amortization expense in Virginia Power s Consolidated Statements of Income.

In 2014, Virginia Power also made a one-time adjustment to depreciation expense as ordered by the Virginia Commission. This adjustment resulted in an increase of $38 million ($23 million after-tax) in depreciation and amortization expense in Virginia Power s Consolidated Statements of Income.

In 2013, Dominion Gas revised the depreciation rates for East Ohio to reflect the results of a new depreciation study. This change resulted in a decrease of $8 million ($5 million after-tax) in depreciation and amortization expense in Dominion Gas Consolidated Statements of Income.

Dominion s nonutility property, plant and equipment is depreciated using the straight-line method over the following estimated useful lives:

Asset	Estimated Useful Lives
Merchant generation-nuclear	**44 years**
Merchant generation-other	**15 - 36 years**
General and other	**5 - 59 years**

Depreciation and amortization related to Virginia Power s and Dominion Gas nonutility property, plant and equipment and E&P properties was immaterial for the years ended December 31, 2015, 2014 and 2013.

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

Long-Lived and Intangible Assets

The Companies 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. Intangible assets with finite lives are amortized over their estimated useful lives. See Note 6 for a discussion of impairments related to certain long-lived assets.

Regulatory Assets and Liabilities

The accounting for Dominion s and Dominion Gas regulated gas and Virginia Power s regulated electric operations differs from the accounting for nonregulated operations in that they are required to reflect the effect of rate regulation in their 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, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

The Companies evaluate whether or not recovery of their regulatory assets through future rates is probable and make various assumptions in their analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. 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.

Asset Retirement Obligations

The Companies recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. At least annually, the Companies evaluate the key assumptions underlying their AROs including estimates of the amounts and timing of future cash flows associated with retirement activities. AROs are adjusted when significant changes in these assumptions are identified. Dominion and Dominion Gas report accretion of AROs and depreciation on asset retirement costs associated with their natural gas pipeline and storage well assets as an adjustment to the related regulatory liabilities when revenue is recoverable from customers for AROs. Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with decommissioning its nuclear power stations as an adjustment to the regulatory liability for certain jurisdictions. Additionally, Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with certain prospective rider projects as an adjustment to the regulatory asset for certain jurisdictions. Accretion of all other AROs and depreciation of all other asset retirement costs are reported in other operations and maintenance expense and depreciation expense, respectively, in the Consolidated Statements of Income.

Debt Issuance Costs

The Companies 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. Deferred debt issuance costs are recorded as an asset and classified in other current assets and other deferred charges and other assets in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest expense. Unamortized costs associated with redemptions of debt securities prior to stated maturity dates are generally recognized and recorded in interest expense immediately. Effective January 2016, deferred debt issuance costs will be recorded as a reduction in long-term debt in the Consolidated Balance Sheets. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation are deferred and amortized over the lives of the new issuances.

Investments

Marketable Equity and Debt Securities

Dominion accounts for and classifies investments in marketable equity and debt securities as trading or available-for-sale securities. Virginia Power classifies investments in marketable equity and debt securities as available-for-sale securities.

Trading securities include marketable equity and debt securities held by Dominion in rabbi trusts associated with certain deferred compensation plans. These securities are reported in other investments in the Consolidated Balance Sheets at fair value with net realized and unrealized gains and losses included in other income in the Consolidated Statements of Income.

Available-for-sale securities include all other marketable equity and debt securities, primarily comprised of securities held in the nuclear decommissioning trusts. These investments are reported at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets. Net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in Virginia Power s nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other available-for-sale securities, including those held in Dominion s merchant generation nuclear decommissioning trusts, net realized and unrealized gains and losses (including any other-than-temporary impairments) are included in other income and unrealized gains and losses are reported as a component of AOCI, after-tax.

In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

Non-marketable Investments

The Companies account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Non-marketable investments include:

Equity method investments when the Companies have the ability to exercise significant influence, but not control, over the investee. Dominion s investments are included in investments in equity method affiliates and Virginia Power s investments are included in other investments in their Consolidated Balance Sheets. The Companies record equity method adjustments in other income in the Consolidated Statements of Income including: their proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, amortization of certain differences between the carrying value and the equity in the net assets of the investee at the date of investment and other adjustments required by the equity method.

Cost method investments when Dominion and Virginia Power do not have the ability to exercise significant influence over the investee.

Dominion s and Virginia Power s investments are included in other investments and nuclear decommissioning trust funds.

Other-than-temporary Impairment

Dominion and Virginia Power periodically review their investments to determine whether a decline in fair value should be considered other-than-temporary. 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.

Decommissioning Trust Investments Special Considerations

The recognition provisions of the FASB s other-than-temporary impairment guidance apply only to debt securities classified as available-for-sale or held-to-maturity, while the presentation and disclosure requirements apply to both debt and equity securities.

Debt Securities Using information obtained from their nuclear decommissioning trust fixed-income investment managers, Dominion and Virginia Power record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more-likely-than-not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. If that is not the case, but the debt security is deemed to have experienced a credit loss, Dominion and Virginia Power record the credit loss in earnings and any remaining portion of the unrealized

Combined Notes to Consolidated Financial Statements, Continued

loss in AOCI. Credit losses are evaluated primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors.

Equity securities and other investments Dominion s and Virginia Power s method of assessing other-than-temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since Dominion and Virginia Power have limited ability to oversee the day-to-day management of nuclear decommissioning trust fund investments, they do not have the ability to ensure investments are held through an anticipated recovery period. Accordingly, they consider all equity and other securities as well as non-marketable investments held in nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory for Dominion Gas used in East Ohio gas distribution operations is valued using the LIFO method. Under the LIFO method, stored gas inventory was valued at $24 million and $12 million at December 31, 2015 and December 31, 2014, respectively. Based on the average price of gas purchased during 2015 and 2014, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by $109 million and $98 million, respectively. Stored gas inventory for Dominion held by Hope and 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. Dominion and Dominion Gas value these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Dominion and Dominion Gas from other parties are reported in other current assets and imbalances that Dominion and Dominion Gas owe to other parties are reported in other current liabilities in the Consolidated Balance Sheets.

Goodwill

Dominion and Dominion Gas 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.

New Accounting Standards

In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this revised accounting guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

For the Companies, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018. The Companies are currently in the preliminary stages of evaluating the impact of this guidance on their results of operations and overall liquidity. The Companies plan to complete their preliminary assessment, which includes a subset of representative contracts, in 2016. Once their initial evaluation is complete, the Companies will expand the scope of their assessment to include all contracts with customers. Other than increased disclosures, the impacts of the revised accounting guidance to the results of operations and cash flows of the Companies cannot be determined until their assessment process is complete.

In November 2015, the FASB issued revised accounting guidance to simplify the presentation of deferred income taxes. This update requires that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Balance Sheet. The Companies have adopted this guidance on a prospective basis for the period ended December 31, 2015. For prior periods, the Companies have presented deferred taxes in either the current or noncurrent sections of the Consolidated Balance Sheets based on the classification of the related financial accounting assets or liabilities, or, for items such as operating loss carryforwards, the period in which the deferred taxes were expected to reverse.

In January 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of financial instruments. Most notably the update revises the accounting for equity securities, except for those accounted for under the equity method of accounting or resulting in consolidation, by requiring equity securities to be measured at fair value with the changes in fair value recognized in net income. However, an entity may measure equity investments that do not have a readily determinable fair value at cost minus impairment, if any, plus changes from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. The guidance also simplifies the impairment assessment of equity investments without readily determinable fair values, revises the presentation of financial assets and liabilities and amends certain disclosure requirements associated with the fair value of financial instruments. The guidance is effective for the Companies interim and annual reporting periods beginning January 1, 2018, with a cumulative-effect adjustment to the balance sheet. Amendments related to equity securities without readily determinable fair values are to be applied prospectively to such investments that exist as of the date of adoption. The Companies are currently evaluating the impact the adoption of the standard will have on their consolidated financial statements and disclosures.

In February 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. The guidance is effective for the Companies interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Companies are currently evaluating the impact the adoption of the standard will have on their consolidated financial statements and disclosures.

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NOTE 3. ACQUISITIONS AND DISPOSITIONS

DOMINION

PROPOSED ACQUISITION OF QUESTAR

Pursuant to the terms of the Questar Combination announced in February 2016, upon closing, each share of Questar common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $25 in cash per share, or approximately $4.4 billion in total. In addition, Questar s debt, which currently totals approximately $1.6 billion is expected to remain outstanding. Additionally, Dominion entered into agreements with several of its lending banks pursuant to which they have committed to provide temporary debt financing consisting of a $3.9 billion acquisition facility. Dominion intends to permanently finance the transaction in a manner that supports its existing credit ratings targets by issuing a combination of common stock, mandatory convertibles (including RSNs) and debt at Dominion, and indirectly through an issuance of common units at Dominion Midstream, the proceeds of which will be applied to pay Dominion for certain assets of Questar, which are expected to be contributed to Dominion Midstream.

The transaction requires approval of Questar s shareholders and clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. Questar and Dominion also will file for review and approval, as required, from the Utah Public Service Commission and the Wyoming Public Service Commission, and provide information regarding the transaction to the Idaho Public Utilities Commission. In February 2016, the Federal Trade Commission granted antitrust approval of the Questar Combination under the Hart-Scott-Rodino Act. The Questar Combination contains certain termination rights for both Dominion and Questar, and provides that, upon termination of the Questar Combination under specified circumstances, Dominion would be required to pay a termination fee of $154 million to Questar and Questar would be required to pay Dominion a termination fee of $99 million. Subject to receipt of Questar shareholder and any required regulatory approvals and meeting closing conditions, Dominion targets closing by the end of 2016.

WHOLLY-OWNED MERCHANT SOLAR PROJECTS

Acquisitions

The following table presents significant completed acquisitions of wholly-owned merchant solar projects by Dominion in 2014 and 2015. Long-term power purchase, interconnection and operation and maintenance agreements have been executed for all of the projects. Dominion has claimed and/or expects to claim federal investment tax credits on the projects. These projects are included in the Dominion Generation operating segment.

Completed Acquisition Date	Seller	Number of Projects	Project Location	Project Name(s)	Initial Acquisition Cost (millions)[1]	Project Cost (millions)[2]	Date of Commercial Operations	MW Capacity
March 2014	Recurrent Energy Development Holdings, LLC	6	California	Camelot, Kansas, Kent South, Old River One, Adams East, Columbia 2	$ 50	$ 428	Fourth quarter 2014	139
November 2014	CSI Project Holdco, LLC	1	California	West Antelope	79	79	November 2014	20
December 2014	EDF Renewable Development, Inc.	1	California	CID	71	71	January 2015	20
April 2015		**1**	**California**	**Alamo**	**66**	**66**	**May 2015**	**20**

	EC&R NA Solar PV, LLC							
April 2015	**EDF Renewable Development, Inc.**	**3**	**California**	**Cottonwood(3)**	**106**	**106**	**May 2015**	**24**
June 2015	**EDF Renewable Development, Inc.**	**1**	**California**	**Catalina 2**	**68**	**68**	**July 2015**	**18**
July 2015	**SunPeak Solar, LLC**	**1**	**California**	**Imperial Valley 2**	**42**	**71**	**August 2015**	**20**
November 2015	**EC&R NA Solar PV, LLC**	**1**	**California**	**Maricopa West**	**65**	**65**	**December 2015**	**20**
November 2015	**Community Energy, Inc.**	**1**	**Virginia**	**Eastern Shore Solar**	**34**	**212**	**October 2016**	**80**

(1) The purchase price was primarily allocated to Property, Plant and Equipment.
(2) Includes acquisition cost.
(3) One of the projects, Marin Carport, is expected to begin commercial operations in 2016.

Sale of Interest in Merchant Solar Projects

In September 2015, Dominion signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then currently wholly-owned merchant solar projects, 24 solar projects totaling approximately 425 MW, to SunEdison for approximately $300 million. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with

the sale of interest in the remaining projects completed in January 2016. SunEdison subsequently sold its interest in these projects to Terra Nova Renewable Partners. SunEdison has a future option to buy all or a portion of Dominion s remaining 67% ownership in the projects upon the occurrence of certain events, none of which had occurred as of December 31, 2015 nor are expected to occur in 2016.

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Non-Wholly-Owned Merchant Solar Projects

Acquisitions of Four Brothers and Three Cedars

In June 2015, Dominion acquired 50% of the units in Four Brothers from SunEdison for $64 million of consideration, consisting of $2 million in cash and a $62 million payable. As of December 31, 2015, a $43 million payable is included in other current liabilities in Dominion s Consolidated Balance Sheets. Four Brothers purpose is to develop and operate four solar projects located in Utah, which will produce and sell electricity and renewable energy credits. The projects are expected to cost approximately $730 million to construct, including the initial acquisition cost. Dominion is obligated to contribute $445 million of capital to fund the construction of the projects and had contributed $138 million through December 31, 2015. The facilities are expected to begin commercial operations in the third quarter of 2016, generating approximately 320 MW.

In September 2015, Dominion acquired 50% of the units in Three Cedars from SunEdison for $43 million of consideration, consisting of $6 million in cash and a $37 million payable. As of December 31, 2015, a $29 million payable is included in other current liabilities in Dominion s Consolidated Balance Sheets. Three Cedars purpose is to develop and operate three solar projects located in Utah, which will produce and sell electricity and renewable energy credits. The projects are expected to cost approximately $425 million to construct. Dominion is obligated to contribute $276 million of capital to fund the construction of the projects and had contributed $60 million through December 31, 2015. The facilities are expected to begin commercial operations in the third quarter of 2016, generating approximately 210 MW.

Long-term power purchase, interconnection and operation and maintenance agreements have been executed for both Four Brothers and Three Cedars. Dominion expects to claim 99% of the federal investment tax credits on the projects.

Dominion owns 50% of the voting interests in Four Brothers and Three Cedars and has a controlling financial interest over the entities through its rights to control operations. The allocation of the $64 million purchase price for Four Brothers resulted in $89 million of property, plant and equipment and $25 million of noncontrolling interest. The allocation of the $43 million purchase price for Three Cedars resulted in $65 million of property, plant and equipment and $22 million of noncontrolling interest. The noncontrolling interest for each entity was measured at fair value using the discounted cash flow method, with the primary components of the valuation being future cash flows (both incoming and outgoing) and the discount rate. Dominion determined its discount rate based on the cost of capital a utility-scale investor would expect, as well as the cost of capital an individual project developer could achieve via a combination of non-recourse project financing and outside equity partners. The acquired assets of Four Brothers and Three Cedars are included in the Dominion Generation operating segment.

Four Brothers and Three Cedars have entered into agreements with SunEdison to provide administrative and support services in connection with the construction of the projects, operation and maintenance of the facilities, and administrative and technical management services of the solar facilities. In addition, Dominion has entered into contracts with SunEdison to provide services

related to construction project management and oversight. Costs related to services to be provided under these agreements were immaterial for the year ended December 31, 2015. Subsequent to Dominion s acquisition of Four Brothers and Three Cedars through December 31, 2015, SunEdison made contributions to Four Brothers and Three Cedars of $103 million in aggregate, which are reflected as noncontrolling interests in the Consolidated Balance Sheets.

In December 2015, SunEdison entered an agreement to sell its interest in Four Brothers and Three Cedars through the sale of Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC to DESRI.

Dominion Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois, which owns and operates a 416-mile, FERC-regulated natural gas transmission pipeline in New York and Connecticut. In exchange for this partnership interest, Dominion Midstream issued 8.6 million common units representing limited partnership interests in Dominion Midstream (6.8 million common units to NG for its 20.4% interest and 1.8 million common units to NJNR for its 5.53% interest). The investment was recorded at $216 million based on the value of Dominion Midstream s common units at closing. These common units are reflected as noncontrolling interest in Dominion s Consolidated Financial Statements. Dominion Midstream s noncontrolling partnership interest is reflected in the Dominion Energy operating segment. In addition to this acquisition, Dominion Gas currently holds a 24.72% noncontrolling partnership interest in Iroquois. Dominion Midstream and Dominion Gas each account for their interest in Iroquois as an equity method investment. See Notes 9 and 15 for more information regarding Iroquois.

Acquisition of DCG

In January 2015, Dominion completed the acquisition of 100% of the equity interests of DCG from SCANA Corporation for $497 million in cash, as adjusted for working capital. DCG owns and operates nearly 1,500 miles of FERC-regulated interstate natural gas pipeline in South Carolina and southeastern Georgia. This acquisition supports Dominion s natural gas expansion into the southeastern U.S. The allocation of the purchase price resulted in $277 million of net property, plant and equipment, $250 million of goodwill, of which approximately $225 million is expected to be deductible for income tax purposes, and $38 million of regulatory liabilities. The goodwill reflects the value associated with enhancing Dominion s regulated gas position, economic value attributable to future expansion projects as well as increased opportunities for synergies. The acquired assets of DCG are included in the Dominion Energy operating segment.

On March 24, 2015, DCG converted to a limited liability company under the laws of South Carolina and changed its name from Carolina Gas Transmission Corporation to DCG. On April 1, 2015, Dominion contributed 100% of the issued and outstanding membership interests of DCG to Dominion Midstream in exchange for total consideration of $501 million, as adjusted for working capital. Total consideration to Dominion consisted of the issuance of a two-year, $301 million senior unsecured promissory note payable by Dominion Midstream at an annual interest rate of 0.6%, and 5,112,139 common units, valued at $200 million, representing limited partner interests in Dominion Midstream. The number of units was based on the volume weighted average trading price of Dominion Midstream s common units for the ten trading days prior to April 1, 2015, or $39.12 per unit. Since Dominion consolidates Dominion Midstream for financial reporting purposes, this transaction was eliminated upon consolidation and did not impact Dominion s financial position or cash flows.

Sale of Electric Retail Energy Marketing Business

In March 2014, Dominion completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale resulted in a gain, subject to post-closing adjustments, of $100 million ($57 million after-tax) net of a $31 million write-off of goodwill, and is included in other operations and maintenance expense in Dominion s Consolidated Statements of Income. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification.

Sale of Illinois Gas Contracts

In June 2013, Dominion completed the sale of Illinois Gas Contracts. The sales price was $32 million, subject to post-closing adjustments. The sale resulted in a gain of $29 million ($18 million after-tax) net of a $3 million write-off of goodwill, and is included in other operations and maintenance expense in Dominion s Consolidated Statement of Income. The sale of Illinois Gas Contracts did not qualify for discontinued operations classification as it is not considered a component under applicable accounting guidance.

Sale of Brayton Point, Kincaid and Equity Method Investment in Elwood

In March 2013, Dominion entered into an agreement with Energy Capital Partners to sell Brayton Point, Kincaid, and its equity method investment in Elwood.

In the first and second quarters of 2013, Brayton Point s and Kincaid s assets and liabilities to be disposed were classified as held for sale and adjusted to their estimated fair value less cost to sell, resulting in impairment charges totaling $48 million ($28 million after-tax), which are included in discontinued operations in Dominion s Consolidated Statements of Income. In both periods, Dominion used the market approach to estimate the fair value of Brayton Point s and Kincaid s long-lived assets. These were considered Level 2 fair value measurements given that they were based on the agreed-upon sales price.

Dominion s 50% interest in Elwood was an equity method investment and therefore, in accordance with applicable accounting guidance, the carrying amount of this investment was not classified as held for sale nor were the equity earnings from this investment reported as discontinued operations.

In August 2013, Dominion completed the sale and received proceeds of $465 million, net of transaction costs. The sale resulted in a $35 million ($25 million after-tax) gain attributable to its equity method investment in Elwood, which is included in other income in Dominion s Consolidated Statement of Income, which was partially offset by a $17 million ($18 million after-tax) loss attributable to Brayton Point and Kincaid, which includes a $16 million write-off of goodwill and is reflected in loss from discontinued operations in Dominion s Consolidated Statement of Income.

The following table presents selected information regarding the results of operations of Brayton Point and Kincaid, which are reported as discontinued operations in Dominion s Consolidated Statements of Income:

Year Ended December 31,	2013
(millions)	
Operating revenue	$ 304
Loss before income taxes	(135)[(1)]

(1) Includes $64 million of charges related to the defeasance of Brayton Point debt and the early redemption of Kincaid debt in 2013.

Virginia Power

ACQUISITION OF SOLAR PROJECT

In December 2015, Virginia Power completed the acquisition of 100% of a solar development project in North Carolina from Morgans Corner for $47 million, all of which was allocated to property, plant and equipment. The project was placed into service in December 2015 with a total cost of $49 million, including the initial acquisition cost. The project generates approximately 20 MW. The output generated by the project will be used to meet a ten year non-jurisdictional supply agreement with the U.S. Navy, which has the unilateral option to extend for an additional ten years. In October 2015, the North Carolina Commission granted the transfer of the existing CPCN from Morgans Corner to Virginia Power. The acquired asset is included in the Virginia Power Generation operating segment.

Dominion and Dominion Gas

BLUE RACER

See Note 9 for a discussion of transactions related to Blue Racer.

ASSIGNMENTS OF SHALE DEVELOPMENT RIGHTS

See Note 10 for a discussion of assignments of shale development rights.

Combined Notes to Consolidated Financial Statements, Continued

NOTE 4. OPERATING REVENUE

The Companies operating revenue consists of the following:

Year Ended December 31, (millions)	2015	2014	2013
Dominion			
Electric sales:			
Regulated	**$ 7,482**	$ 7,460	$ 7,193
Nonregulated	**1,488**	1,839	2,511
Gas sales:			
Regulated	**218**	334	323
Nonregulated	**471**	751	930
Gas transportation and storage	**1,616**	1,543	1,535
Other	**408**	509	628
Total operating revenue	**$ 11,683**	$ 12,436	$ 13,120
Virginia Power			
Regulated electric sales	**$ 7,482**	$ 7,460	$ 7,193
Other	**140**	119	102
Total operating revenue	**$ 7,622**	$ 7,579	$ 7,295
Dominion Gas			
Gas sales:			
Regulated	**$ 122**	$ 209	$ 202
Nonregulated	**10**	26	32
Gas transportation and storage	**1,366**	1,353	1,338
NGL revenue	**93**	212	292
Other	**125**	98	73
Total operating revenue	**$ 1,716**	$ 1,898	$ 1,937

NOTE 5. 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. The Companies are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

In December 2015, U.S. federal legislation was enacted, providing an extension of the 50% bonus depreciation allowance for qualifying expenditures incurred in 2015, 2016 and 2017, and a phasing down of the allowance to 40% in 2018 and 30% in 2019 and expiration thereafter. In addition, the legislation extends the 30% investment tax credit for qualifying expenditures incurred through 2019 and provides a phase down of the credit to 26% in 2020, 22% in 2021 and 10% in 2022 and thereafter. U.S. federal legislation had also been enacted in December 2014 to delay the expiration of the bonus depreciation allowance, but only for one year, so that it was available for qualifying expenditures incurred during 2014.

Continuing Operations

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

	Dominion			**Virginia Power**			**Dominion Gas**		
Year Ended December 31, (millions)	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Current:									
Federal	**$ (24)**	$ (11)	$ 317	**$ 316**	$ 85	$ 357	**$ 90**	$ 86	$ 158
State	**75**	14	110	**92**	67	62	**30**	32	41
Total current expense	**51**	3	427	**408**	152	419	**120**	118	199
Deferred:									
Federal									
Taxes before operating loss carry forwards and investment tax credits	**384**	956	563	**154**	381	224	**156**	192	92
Tax utilization (benefit) of operating loss carry forwards	**539**	(352)	(18)	**96**			**6**		
Investment tax credits	**(134)**	(152)	(48)	**(11)**					
State	**66**	(2)	(31)	**13**	16	17	**1**	24	10
Total deferred expense	**855**	450	466	**252**	397	241	**163**	216	102
Amortization of deferred investment tax credits	**(1)**	(1)	(1)	**(1)**	(1)	(1)			
Total income tax expense	**$ 905**	$ 452	$ 892	**$ 659**	$ 548	$ 659	**$ 283**	$ 334	$ 301

In 2015, Dominion s current federal income tax benefit includes the recognition of a $20 million benefit related to a carryback to be filed for nuclear decommissioning expenditures included in its 2014 net operating loss.

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

	Dominion			Virginia Power			Dominion Gas		
Year Ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
U.S. statutory rate	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:									
State taxes, net of federal benefit	**3.7**		2.1	**3.9**	3.8	3.1	**2.7**	4.4	4.3
Investment tax credits	**(4.7)**	(8.6)	(1.8)	**(0.6)**					
Production tax credits	**(0.8)**	(1.2)	(0.6)	**(0.6)**	(0.6)	(0.2)			
Valuation allowances	**(0.3)**	0.7	(0.1)						
AFUDC - equity	**(0.3)**		(0.6)	**(0.6)**		(0.8)	**0.2**		(0.1)
Employee stock ownership plan deduction	**(0.6)**	(0.9)	(0.6)						
Other, net		0.4	(0.4)	**0.6**	0.8	(0.4)	**0.3**	0.1	0.3
Effective tax rate	**32.0%**	25.4%	33.0%	**37.7%**	39.0%	36.7%	**38.2%**	39.5%	39.5%

Dominion s effective tax rate in 2014 reflects the recognition of state tax credits and previously unrecognized tax benefits due to the expiration of statutes of limitations. Dominion Gas effective tax rate in 2015 reflects a benefit resulting from the impact of changes in the allocation of income among states on existing deferred taxes.

The Companies deferred income taxes consist of the following:

	Dominion		Virginia Power		Dominion Gas	
At December 31,	**2015**	2014	**2015**	2014	**2015**	2014
(millions)						
Deferred income taxes:						
Total deferred income tax assets	**$ 1,152**	$ 2,023	**$ 164**	$ 500	**$ 129**	$ 227
Total deferred income tax liabilities	**8,552**	8,663	**4,805**	4,915	**2,343**	2,289
Total net deferred income tax liabilities	**$ 7,400**	$ 6,640	**$ 4,641**	$ 4,415	**$ 2,214**	$ 2,062
Total deferred income taxes:						
Plant and equipment, primarily depreciation method and basis differences	**$ 6,299**	$ 5,895	**$ 4,133**	$ 3,965	**$ 1,541**	$ 1,417
Nuclear decommissioning	**1,158**	1,241	**378**	474		
Deferred state income taxes	**646**	659	**302**	299	**205**	207
Federal benefit of deferred state income taxes	**(226)**	(231)	**(106)**	(105)	**(72)**	(72)
Deferred fuel, purchased energy and gas costs	**(1)**	27	**(3)**	18	**1**	7
Pension benefits	**291**	272	**(99)**	(77)	**613**	567
Other postretirement benefits	**(15)**	(17)	**30**	13	**(7)**	(12)
Loss and credit carryforwards	**(1,004)**	(1,434)	**(53)**	(116)	**(4)**	(10)
Valuation allowances	**73**	87				
Partnership basis differences	**367**	304			**41**	42
Other	**(188)**	(163)	**59**	(56)	**(104)**	(84)
Total net deferred income tax liabilities	**$ 7,400**	$ 6,640	**$ 4,641**	$ 4,415	**$ 2,214**	$ 2,062

At December 31, 2015, Dominion had the following deductible loss and credit carryforwards:

Federal loss carryforwards of $594 million that expire if unutilized during the period 2021 through 2034;
Federal investment tax credits of $407 million that expire if unutilized during the period 2033 through 2035;
Federal production and other tax credits of $89 million that expire if unutilized during the period 2031 through 2035;

- State loss carryforwards of $1.6 billion that expire if unutilized during the period 2018 through 2034. A valuation allowance on $1.1 billion of these carryforwards has been established;
- State minimum tax credits of $145 million that do not expire; and
- State investment tax credits of $40 million that expire if unutilized during the period 2019 through 2024.

At December 31, 2015, Virginia Power had the following deductible loss and credit carryforwards:

- Federal loss carryforwards of $7 million that expire if unutilized during the period 2031 through 2034;
- Federal investment, production and other tax credits of $38 million that expire if unutilized during the period 2031 through 2035; and
- State investment tax credits of $9 million that expire if unutilized by 2024.

At December 31, 2015, Dominion Gas had federal loss carryforwards of $10 million that expire if unutilized during the period 2031 through 2034 and no credit carryforwards.

Combined Notes to Consolidated Financial Statements, Continued

A reconciliation of changes in the Companies unrecognized tax benefits follows:

	Dominion			Virginia Power			Dominion Gas		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
(millions)									
Balance at January 1	**$ 145**	$ 222	$ 293	**$ 36**	$ 39	$ 57	**$ 29**	$ 29	$ 30
Increases-prior period positions	**2**	24	17		2	12			
Decreases-prior period positions	**(40)**	(26)	(99)	**(25)**	(16)	(42)			(1)
Increases-current period positions	**8**	16	30	**1**	11	14			
Decreases-current period positions			(5)						
Settlements with tax authorities	**(5)**		(2)			(2)			
Expiration of statutes of limitations	**(7)**	(91)	(12)						
Balance at December 31	**$ 103**	$ 145	$ 222	**$ 12**	$ 36	$ 39	**$ 29**	$ 29	$ 29

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. For Dominion and its subsidiaries, these unrecognized tax benefits were $69 million, $77 million and $126 million at December 31, 2015, 2014 and 2013, respectively. For Dominion, the change in these unrecognized tax benefits decreased income tax expense by $6 million, $47 million and $29 million in 2015, 2014 and 2013, respectively. For Virginia Power, these unrecognized tax benefits were $8 million at December 31, 2015, 2014 and 2013. For Virginia Power, the change in these unrecognized tax benefits affected income tax expense by less than $1 million in both 2015 and 2014, and increased income tax expense by $4 million in 2013. For Dominion Gas, these unrecognized tax benefits were $19 million at December 31, 2015, 2014 and 2013. For Dominion Gas, the change in these unrecognized tax benefits affected income tax expense by less than $1 million in 2015, 2014 and 2013.

The IRS examination of tax years 2008, 2009, 2010 and 2011 concluded in late 2013, resulting in a payment of $46 million, and an adjustment to a refund previously received by Dominion for its carryback of 2008 losses to 2007. The loss carryback, as adjusted, was submitted to the U.S. Congressional Joint Committee on Taxation for review. Early in 2014, Dominion received notification that the matter had been resolved with no further adjustments.

Effective for its 2014 tax year, Dominion was accepted into the CAP. Through the CAP, Dominion has the opportunity to resolve complex tax matters with the IRS before filing its federal income tax returns, thus achieving certainty for such tax return filing positions agreed to by the IRS. Under a Pre-CAP plan, the IRS audit of tax years 2012 and 2013 began in early 2014 and

concluded in late 2015. The IRS audit of CAP tax year 2014 also began in 2014. The IRS issued a partial acceptance letter in late 2015 and completed its post-filing review of the 2014 tax year in early 2016. The IRS audit of CAP tax year 2015 began in 2015. Accordingly, Dominion s earliest tax year remaining open for federal examination is 2015.

It is reasonably possible that settlement negotiations and expiration of statutes of limitations could result in a decrease in unrecognized tax benefits in 2016 by up to $30 million for Dominion and $22 million for Dominion Gas. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by up to $15 million for Dominion and $10 million for Dominion Gas.

Otherwise, with regard to 2015 and prior years, Dominion and Dominion Gas cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2016.

After considering the possibility of potential changes in the status of its remaining unrecognized tax benefits, Virginia Power has concluded that no significant changes are reasonably possible to occur in 2016.

For each of the major states in which Dominion operates, the earliest tax year remaining open for examination is as follows:

State	**Earliest Open Tax Year**
Pennsylvania[1]	**2010**
Connecticut	**2012**
Virginia[2]	**2012**
West Virginia[1]	**2012**
New York[1]	**2007**

(1) Considered a major state for Dominion Gas operations.
(2) Considered a major state for Virginia Power s operations.

The Companies are also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if Dominion utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

Discontinued Operations

Details of income tax expense for Dominion s discontinued operations were as follows:

Year Ended December 31,	2013
(millions)	
Current:	
Federal	$ (274)
State	(41)
Total current benefit	(315)
Deferred:	
Federal	232
State	40
Total deferred expense	272
Total income tax benefit	$ (43)

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Dominion s effective tax rate for 2013 reflects the impact of goodwill written off in the sale of Kincaid and Brayton Point that is not deductible for tax purposes.

NOTE 6. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of the Companies own nonperformance risk on their liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). Dominion and Virginia Power apply fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments, and nuclear decommissioning trust and other investments including those held in Dominion s rabbi, pension and other postretirement benefit plan trusts, in accordance with the requirements described above. Dominion Gas applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and investments held in pension and other postretirement benefit plan trusts, in accordance with the requirements described above. The Companies apply credit adjustments to their derivative fair values in accordance with the requirements described above. These credit adjustments are currently not material to the derivative fair values.

Inputs and Assumptions

The Companies maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, the Companies consider whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if the Companies believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the Companies must estimate

prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect their market assumptions.

The Companies commodity derivative valuations are prepared by Dominion s ERM department. The ERM department creates daily mark-to-market valuations for the Companies derivative transactions using computer-based statistical models. The inputs that go into the market valuations are transactional information stored in the systems of record and market pricing information that resides in data warehouse databases. The majority of forward prices are automatically uploaded into the data warehouse databases from various third-party sources. Inputs obtained from third-party sources are evaluated for reliability considering the reputation, independence, market presence, and methodology used by the third-party. If forward prices are not available from third-party sources, then the ERM department models the forward prices based on other available market data. A team consisting of risk management and risk quantitative analysts meets each business day to assess the validity of market prices and mark-to-market valuations. During this meeting, the changes in mark-to-market valuations from period to period are examined and qualified against historical expectations. If any discrepancies are identified during this process, the mark-to-market valuations or the market pricing information is evaluated further and adjusted, if necessary.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, Dominion and Virginia Power generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. Dominion and Virginia Power 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, the Companies may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract s estimated fair value.

The inputs and assumptions used in measuring fair value include the following:

For commodity derivative contracts:

- Forward commodity prices
- Transaction prices
- Price volatility
- Price correlation
- Volumes
- Commodity location
- Interest rates
- Credit quality of counterparties and the Companies
- Credit enhancements
- Time value

Combined Notes to Consolidated Financial Statements, Continued

For interest rate derivative contracts:

- Interest rate curves
- Credit quality of counterparties and the Companies
- Volumes
- Credit enhancements
- Time value

For investments:

- Quoted securities prices and indices
- Securities trading information including volume and restrictions
- Maturity
- Interest rates
- Credit quality
- NAV (for alternative investments and common/collective trust funds)

The Companies regularly evaluate and validate the inputs used to estimate fair value by a number of methods, including review and verification of models, as well as various market price verification procedures such as the use of pricing services and multiple broker quotes to support the market price of the various commodities and investments in which the Companies transact.

Levels

The Companies also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

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

Level 2 Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include commodity forwards and swaps, interest rate swaps, restricted cash equivalents, and certain Treasury securities, money market funds, common/collective trust funds, and corporate, state and municipal debt securities held in nuclear decommissioning trust funds for Dominion and Virginia Power, benefit plan trust funds for Dominion and Dominion Gas, and rabbi trust funds for Dominion.

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for the Companies consist of long-dated commodity derivatives, FTRs, natural gas peaking options and other modeled commodity derivatives. Additional instruments categorized in Level 3 for Dominion and Dominion Gas include alternative investments, consisting of investments in partnerships, joint ventures and other alternative investments, held in benefit plan trust funds.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

For derivative contracts, the Companies recognize transfers among Level 1, Level 2 and Level 3 based on fair values as of the first day of the month in which the transfer occurs. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable for classification in either Level 1 or Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Companies over-the-counter derivative contracts is subject to change.

Level 3 Valuations

Fair value measurements are categorized as Level 3 when price or other inputs that are considered to be unobservable are significant to their valuations. Long-dated commodity derivatives are generally based on unobservable inputs due to the length of time to settlement and the absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which are generally not considered to be liquid markets. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non- transparent and illiquid markets. Alternative investments are categorized as Level 3 due to the absence of quoted market prices, illiquidity and the long-term nature of these assets. These investments are generally valued using NAV based on the proportionate share of the fair value as determined by reference to the most recent audited fair value financial statements or fair value statements provided by the investment manager adjusted for any significant events occurring between the investment manager s and the Companies measurement date.

The Companies enter into certain physical and financial forwards, futures, options and swaps, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical and financial forwards and futures contracts. An option model is used to value Level 3 physical and financial options. The discounted cash flow model for forwards and futures calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. The option model calculates mark-to-market valuations using variations of the Black-Scholes option model. The inputs into the models are the forward market prices, implied price volatilities, risk-free rate of return, the option expiration dates, the option strike prices, the original sales prices,

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and volumes. For Level 3 fair value measurements, forward market prices, credit spreads and implied price volatilities are considered unobservable. The unobservable inputs are developed and substantiated using historical information, available market data,

third-party data, and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships, and changes in third-party pricing sources.

The following table presents Dominion s quantitative information about Level 3 fair value measurements at December 31, 2015. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility and credit spreads.

	Fair Value (millions)		Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets:						
Physical and Financial Forwards and Futures:						
Natural Gas(2)	**$**	**97**	Discounted Cash Flow	Market Price (per Dth)(4)	(2) - 8	(1)
				Credit Spread(5)	1% - 6%	3%
Liquids(3)		**4**	Discounted Cash Flow	Market Price (per Gal)(4)	0 - 2	1
FTRs		**9**	Discounted Cash Flow	Market Price (per MWh)(4)	(2) - 14	1
Physical and Financial Options:						
Natural Gas		**4**	Option Model	Market Price (per Dth)(4)	2 - 3	3
				Price Volatility(6)	25% - 58%	37%
Total assets	**$**	**114**				
Liabilities:						
Physical and Financial Forwards and Futures:						
Natural Gas(2)	**$**	**9**	Discounted Cash Flow	Market Price (per Dth)(4)	(2) - 3	2
FTRs		**3**	Discounted Cash Flow	Market Price (per MWh)(4)	(9) - 9	2
Physical and Financial Options:						
Natural Gas		**7**	Option Model	Market Price (per Dth)(4)	2 - 5	3
				Price Volatility(6)	25% - 58%	35%
Total liabilities	**$**	**19**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Includes NGLs and oil.
(4) Represents market prices beyond defined terms for Levels 1 and 2.
(5) Represents credit spreads unrepresented in published markets.
(6) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement

Market Price	Buy	Increase (decrease)	Gain (loss)
Market Price	Sell	Increase (decrease)	Loss (gain)
Price Volatility	Buy	Increase (decrease)	Gain (loss)
Price Volatility	Sell	Increase (decrease)	Loss (gain)
Credit Spread	Asset	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurements

Dominion

See Note 3 for information regarding the sale of Brayton Point, Kincaid and Dominion s equity method investment in Elwood.

Dominion Gas

Natural Gas Assets

In the fourth quarter of 2014, Dominion Gas recorded an impairment charge of $9 million ($6 million after-tax) in other

operations and maintenance expense in its Consolidated Statements of Income, to write off previously capitalized costs following the cancellation of a development project.

In June 2013, Dominion Gas purchased certain natural gas infrastructure facilities that were previously leased from third parties. The purchase price was based on terms in the lease, which exceeded current market pricing. As a result of the purchase price and expected losses, Dominion Gas recorded an impairment charge of $49 million ($29 million after-tax) in other operations and maintenance expense in its Consolidated Statements of Income, to write down the long-lived assets to their estimated fair values of less than $1 million. As management was not aware of any recent market transactions for comparable assets with sufficient transparency to develop a market approach to fair value, Dominion Gas used the income approach (discounted cash flows) to estimate the fair value of the assets in this impairment test. This was considered a Level 3 fair value measurement due to the use of significant unobservable inputs, including estimates of future production and other commodity prices.

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Combined Notes to Consolidated Financial Statements, Continued

Also in June 2013, Dominion Gas recorded an impairment charge of $6 million ($4 million after-tax) in other operations and maintenance expense in its Consolidated Statements of Income, to write off previously capitalized costs following the cancellation of two development projects.

Recurring Fair Value Measurements

Fair value measurements are separately disclosed by level within the fair value hierarchy with a separate reconciliation of fair value measurements categorized as Level 3. Fair value disclosures for assets held in Dominion s and Dominion Gas pension and other postretirement benefit plans are presented in Note 21.

Dominion

The following table presents Dominion s assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	**$ 1**	**$ 249**	**$ 114**	**$ 364**
Interest rate		**24**		**24**
Investments(1):				
Equity securities:				
U.S.:				
Large Cap	**2,547**			**2,547**
Other	**5**			**5**
REIT	**63**			**63**
Non-U.S.:				
Large Cap	**10**			**10**
Fixed Income:				
Corporate debt instruments		**437**		**437**
U.S. Treasury securities and agency debentures	**458**	**201**		**659**
State and municipal		**376**		**376**
Other		**100**		**100**
Cash equivalents and other	**2**	**2**		**4**
Total assets	**$ 3,086**	**$ 1,389**	**$ 114**	**$ 4,589**
Liabilities:				
Derivatives:				
Commodity	**$**	**$ 141**	**$ 19**	**$ 160**
Interest rate		**183**		**183**
Total liabilities	**$**	**$ 324**	**$ 19**	**$ 343**
At December 31, 2014				
Assets:				
Derivatives:				
Commodity	$ 3	$ 567	$ 125	$ 695
Interest rate		24		24
Investments(1):				

Equity securities:				
U.S.:				
Large Cap	2,669			2,669
Other	6			6
Non-U.S.:				
Large Cap	12			12
Fixed Income:				
Corporate debt instruments		441		441
U.S. Treasury securities and agency debentures	419	190		609
State and municipal		395		395
Other		74		74
Cash equivalents and other	3	10		13
Total assets	$ 3,112	$ 1,701	$ 125	$ 4,938
Liabilities:				
Derivatives:				
Commodity	$ 3	$ 571	$ 18	$ 592
Interest rate		202		202
Total liabilities	$ 3	$ 773	$ 18	$ 794

(1) Includes investments held in the nuclear decommissioning and rabbi trusts.

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The following table presents the net change in Dominion s assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	**2015**	2014	2013
Balance at January 1,	**$ 107**	$ (16)	$ 25
Total realized and unrealized gains (losses):			
Included in earnings	**(5)**	97	(9)
Included in other comprehensive income (loss)	**(9)**	7	1
Included in regulatory assets/liabilities	**(4)**	109	(9)
Settlements	**9**	(88)	(23)
Transfers out of Level 3[1]	**(3)**	(2)	(1)
Balance at December 31,	**$ 95**	$ 107	$ (16)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	**$ 2**	$ 6	$

(1) In March 2015, Dominion changed the classification of certain short term NGL derivatives from Level 3 to Level 2 due to an increase in liquidity in financial forward markets. The transfers out of Level 3 that relate to NGLs for the year ended December 31, 2015 were $9 million.

The following table presents Dominion s gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating Revenue	Electric Fuel and Other Energy-Related Purchases	Purchased Gas	Total
Year Ended December 31, 2015				
Total gains (losses) included in earnings	**$ 6**	**$ (11)**	**$**	**$ (5)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	**1**	**1**		**2**
Year Ended December 31, 2014				
Total gains (losses) included in earnings	$ 4	$ 97	$ (4)	$ 97
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	4	1	1	6
Year Ended December 31, 2013				
Total gains (losses) included in earnings	$ 11	$ (19)	$ (1)	$ (9)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	1		(1)	

Combined Notes to Consolidated Financial Statements, Continued

Virginia Power

The following table presents Virginia Power s quantitative information about Level 3 fair value measurements at December 31, 2015. The range and weighted average are presented in dollars for market price inputs and percentages for credit spreads.

	Fair Value (millions)		Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets:						
Physical and Financial Forwards and Futures:						
FTRs	$	**9**	Discounted Cash Flow	Market Price (per MWh)(3)	(2) - 14	1
Natural gas(2)		**92**	Discounted Cash Flow	Market Price (per Dth)(3)	(2) - 4	(1)
				Credit Spread(4)	1% - 6%	3%
Total assets	$	**101**				
Liabilities:						
Physical and Financial Forwards and Futures:						
FTRs	$	**3**	Discounted Cash Flow	Market Price (per MWh)(3)	(9) - 9	2
Physical and Financial Options:						
Natural gas		**5**	Discounted Cash Flow	Market Price (per Dth)(3)	2 - 5	3
				Price Volatility(5)	32% - 38%	35%
Total liabilities	$	**8**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Represents market prices beyond defined terms for Levels 1 and 2.
(4) Represents credit spreads unrepresented in published markets.
(5) Represents volatilities unrepresented in published markets.

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Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market Price	Buy	Increase (decrease)	Gain (loss)
Market Price	Sell	Increase (decrease)	Loss (gain)
Price Volatility	Buy	Increase (decrease)	Gain (loss)
Price Volatility	Sell	Increase (decrease)	Loss (gain)
Credit Spread	Asset	Increase (decrease)	Loss (gain)

The following table presents Virginia Power s assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	**$**	**$ 13**	**$ 101**	**$ 114**
Interest rate		**13**		**13**
Investments[1]:				
Equity securities:				
U.S.:				
Large Cap	**1,100**			**1,100**
REIT	**63**			**63**
Fixed Income:				
Corporate debt instruments		**238**		**238**
U.S. Treasury securities and agency debentures	**180**	**79**		**259**
State and municipal		**175**		**175**
Other		**34**		**34**
Total assets	**$ 1,343**	**$ 552**	**$ 101**	**$ 1,996**
Liabilities:				
Derivatives:				
Commodity	**$**	**$ 19**	**$ 8**	**$ 27**
Interest rate		**59**		**59**
Total liabilities	**$**	**$ 78**	**$ 8**	**$ 86**
At December 31, 2014				
Assets:				
Derivatives:				
Commodity	$	$ 7	$ 106	$ 113
Investments[1]:				
Equity securities:				
U.S.:				
Large Cap	1,157			1,157
Fixed Income:				
Corporate debt instruments		250		250
U.S. Treasury securities and agency debentures	137	61		198
State and municipal		211		211
Other		23		23
Total assets	$ 1,294	$ 552	$ 106	$ 1,952
Liabilities:				
Derivatives:				
Commodity	$	$ 11	$ 4	$ 15

Interest rate		72		72
Total liabilities	$	$ 83	$ 4	$ 87

(1) Includes investments held in the nuclear decommissioning and rabbi trusts.

The following table presents the net change in Virginia Power s assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	**2015**	2014	2013
Balance at January 1,	**$ 102**	$ (7)	$ 2
Total realized and unrealized gains (losses):			
Included in earnings	**(13)**	96	(17)
Included in regulatory assets/liabilities	**(5)**	109	(9)
Settlements	**13**	(96)	17
Transfers out of Level 3	**(4)**		
Balance at December 31,	**$ 93**	$ 102	$ (7)

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy-related purchases expense in Virginia Power s Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2015, 2014 and 2013.

Dominion Gas

The following table presents Dominion Gas quantitative information about Level 3 fair value measurements at December 31, 2015. The range and weighted average are presented in dollars for market price inputs and percentages for credit spreads.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets:					
Physical and Financial Forwards and Futures:					
NGLs	**$ 6**	Discounted Cash Flow	Market Price (per Gal)(2)	0 - 1	1
Total assets	**$ 6**				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

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Combined Notes to Consolidated Financial Statements, Continued

The following table presents Dominion Gas assets and liabilities for commodity and interest rate derivatives that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
At December 31, 2015				
Assets:				
Commodity	**$**	**$ 5**	**$ 6**	**$ 11**
Total assets	**$**	**$ 5**	**$ 6**	**$ 11**
Liabilities:				
Interest rate	**$**	**$ 14**	**$**	**$ 14**
Total liabilities	**$**	**$ 14**	**$**	**$ 14**
At December 31, 2014				
Assets:				
Commodity	$	$	$ 2	$ 2
Total assets	$	$	$ 2	$ 2
Liabilities:				
Interest rate	$	$ 9	$	9
Total liabilities	$	$ 9	$	$ 9

The following table presents the net change in Dominion Gas derivative assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	**2015**	2014	2013
Balance at January 1,	**$ 2**	$ (6)	$ (12)
Total realized and unrealized gains (losses):			
Included in earnings	**1**	2	1
Included in other comprehensive income (loss)	**(5)**	10	3
Settlements	**(1)**	(4)	2
Transfers out of Level 3(1)	**9**		
Balance at December 31,	**$ 6**	$ 2	$ (6)

(1) In March 2015, Dominion Gas changed the classification of certain short term NGL derivatives from Level 3 to Level 2 due to an increase in liquidity in financial forward markets. The transfers out of Level 3 that relate to NGLs for the year ended December 31, 2015 were $9 million.

The gains and losses included in earnings in the Level 3 fair value category were classified in operating revenue in Dominion Gas Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2015, 2014 and 2013.

Fair Value of Financial Instruments

Substantially all of the Companies financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of cash and cash equivalents, restricted cash (which is recorded in other current assets), customer and other receivables, short-term debt, affiliated current borrowings, payables to affiliates and accounts payable are representative of fair value because of the short-term nature of these instruments. For the Companies financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

At December 31,		**2015**		2014
	Carrying Amount	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
(millions)				
Dominion				
Long-term debt, including securities due within one year(2)	**$ 21,998**	**$ 23,210**	$ 19,723	$ 21,881
Junior subordinated notes(3)	**1,358**	**1,192**	1,374	1,396
Remarketable subordinated notes(3)	**2,086**	**2,129**	2,083	2,362
Virginia Power				
Long-term debt, including securities due within one year(3)	**$ 9,425**	**$ 10,400**	$ 8,937	$ 10,293
Dominion Gas				
Long-term debt, including securities due within one year(3)	**$ 3,292**	**$ 3,299**	$ 2,594	$ 2,672

(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. All fair value measurements are classified as Level 2. 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) Carrying amount includes amounts which represent the unamortized discount and/or premium. At December 31, 2015, and 2014, includes the valuation of certain fair value hedges associated with Dominion s fixed rate debt, of $7 million and $19 million, respectively.

(3) Carrying amount includes amounts which represent the unamortized discount and/or premium.

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NOTE 7. DERIVATIVES AND HEDGE ACCOUNTING ACTIVITIES

The Companies are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products they market and purchase, as well as interest rate risks of their business operations. The Companies use derivative instruments to manage exposure to these risks, and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes. As discussed in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivatives are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives.

Derivative assets and liabilities are presented gross on the Companies   Consolidated Balance Sheets. Dominion s derivative contracts include both over-the-counter transactions and those that are executed on an exchange or other trading platform (exchange contracts) and centrally cleared. Virginia Power s and Dominion Gas   derivative contracts include over-the-counter

transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Exchange contracts utilize a financial intermediary, exchange, or clearinghouse to enter, execute, or clear the transactions. Certain over-the-counter and exchange contracts contain contractual rights of setoff through master netting arrangements, derivative clearing agreements, and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral for over-the-counter and exchange contracts include cash, letters of credit, and other forms of security, none of which are subject to restrictions. Cash collateral is used in the table below to offset derivative assets and liabilities. Certain accounts receivable and accounts payable recognized on the Companies   Consolidated Balance Sheets, as well as letters of credit and other forms of security, all of which are not included in the tables below, are subject to offset under master netting or similar arrangements and would reduce the net exposure.

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Combined Notes to Consolidated Financial Statements, Continued

Dominion

Balance Sheet Presentation

The tables below present Dominion s derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2015			December 31, 2014		
(millions)	**Gross Amounts of Recognized Assets**	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Interest rate contracts:						
Over-the-counter	**$ 24**	**$**	**$ 24**	$ 24	$	$ 24
Commodity contracts:						
Over-the-counter	**217**		**217**	382		382
Exchange	**138**		**138**	298		298
Total derivatives, subject to a master netting or similar arrangement	**379**		**379**	704		704
Total derivatives, not subject to a master netting or similar arrangement	**9**		**9**	15		15
Total	**$ 388**	**$**	**$ 388**	$ 719	$	$ 719

	December 31, 2015				December 31, 2014			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ 24**	**$ 22**	**$**	**$ 2**	$ 24	$ 16	$	$ 8
Commodity contracts:								
Over-the-counter	**217**	**37**		**180**	382	34	34	314
Exchange	**138**	**82**		**56**	298	298		
Total	**$ 379**	**$ 141**	**$**	**$ 238**	$ 704	$ 348	$ 34	$ 322

	December 31, 2015			December 31, 2014		
(millions)	**Gross Amounts of Recognized Liabilities**	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Liabilities Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Interest rate contracts:						
Over-the-counter	**$ 183**	**$**	**$ 183**	$ 202	$	$ 202
Commodity contracts:						
Over-the-counter	**70**		**70**	87		87
Exchange	**82**		**82**	493		493
Total derivatives, subject to a master netting or similar arrangement	**335**		**335**	782		782
Total derivatives, not subject to a master netting or similar arrangement	**8**		**8**	12		12
Total	**$ 343**	**$**	**$ 343**	$ 794	$	$ 794

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	December 31, 2015				December 31, 2014			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Net Amounts of Liabilities Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Paid**	**Net Amounts**	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ 183**	**$ 22**	**$**	**$ 161**	$ 202	$ 16	$	$ 186
Commodity contracts:								
Over-the-counter	**70**	**37**		**33**	87	34	1	52
Exchange	**82**	**82**			493	298	195	
Total	**$ 335**	**$ 141**	**$**	**$ 194**	$ 782	$ 348	$ 196	$ 238

Volumes

The following table presents the volume of Dominion s derivative activity as of December 31, 2015. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	**80**	**19**
Basis	**216**	**554**
Electricity (MWh):		
Fixed price	**15,661,078**	
FTRs	**33,350,993**	
Capacity (MW)	**7,600**	
Liquids (Gal)(2)	**83,076,000**	**18,606,000**
Interest rate	**$ 2,950,000,000**	**$ 3,100,000,000**

(1) Includes options.
(2) Includes NGLs and oil.

Ineffectiveness and AOCI

For the years ended December 31, 2015, 2014 and 2013, gains or losses on hedging instruments determined to be ineffective and amounts excluded from the assessment of effectiveness were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion s Consolidated Balance Sheet at December 31, 2015:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ **(7)**	$ **(7)**	**22 months**
Electricity	**76**	**76**	**12 months**
Other	**6**	**6**	**15 months**
Interest rate	**(251)**	**(9)**	**387 months**
Total	$ **(176)**	$ **66**	

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 and interest rates.

Combined Notes to Consolidated Financial Statements, Continued

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion s derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	**$ 101**	**$ 151**	**$ 252**
Interest rate	**3**		**3**
Total current derivative assets	**104**	**151**	**255**
Noncurrent Assets			
Commodity	**3**	**109**	**112**
Interest rate	**21**		**21**
Total noncurrent derivative assets(1)	**24**	**109**	**133**
Total derivative assets	**$ 128**	**$ 260**	**$ 388**
LIABILITIES			
Current Liabilities			
Commodity	**$ 32**	**$ 116**	**$ 148**
Interest rate	**164**		**164**
Total current derivative liabilities	**196**	**116**	**312**
Noncurrent Liabilities			
Commodity		**12**	**12**
Interest rate	**19**		**19**
Total noncurrent derivative liabilities(2)	**19**	**12**	**31**
Total derivative liabilities	**$ 215**	**$ 128**	**$ 343**
At December 31, 2014			
ASSETS			
Current Assets			
Commodity	$ 281	$ 242	$ 523
Interest rate	13		13
Total current derivative assets	294	242	536
Noncurrent Assets			
Commodity	71	101	172
Interest rate	11		11
Total noncurrent derivative assets(1)	82	101	183
Total derivative assets	$ 376	$ 343	$ 719
LIABILITIES			
Current Liabilities			
Commodity	$ 224	$ 267	$ 491
Interest rate	100		100
Total current derivative liabilities	324	267	591
Noncurrent Liabilities			
Commodity	55	46	101

Interest rate	102		102
Total noncurrent derivative liabilities[2]	157	46	203
Total derivative liabilities	$ 481	$ 313	$ 794

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion s Consolidated Balance Sheets.
(2) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion s Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion s derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)[1]	Amount of Gain (Loss) Reclassified from AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment[2]
Year Ended December 31, 2015			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		**$ 203**	
Purchased gas		**(15)**	
Electric fuel and other energy-related purchases		**(1)**	
Total commodity	**$ 230**	**$ 187**	**$ 4**
Interest rate[3]	**(46)**	**(11)**	**(13)**
Total	**$ 184**	**$ 176**	**$ (9)**
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ (130)	
Purchased gas		(13)	
Electric fuel and other energy-related purchases		7	
Total commodity	$ 245	$ (136)	$ (4)
Interest rate[3]	(208)	(16)	(81)
Total	$ 37	$ (152)	$ (85)
Year Ended December 31, 2013			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ (58)	
Purchased gas		(47)	
Electric fuel and other energy-related purchases		(10)	
Total commodity	$ (481)	$ (115)	$ 5
Interest rate[3]	77	(15)	81
Total	$ (404)	$ (130)	$ 86

(1) Amounts deferred into AOCI have no associated effect in Dominion s Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion s Consolidated Statements of Income.
(3) Amounts recorded in Dominion s Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives[1]		
Year Ended December 31, (millions)	**2015**	2014	2013
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue	**$ 24**	$ (310)	$ (45)
Purchased gas	**(14)**	(51)	(9)

Electric fuel and other energy-related purchases	**(14)**	113	(29)
Interest rate[(2)]	**(1)**		
Total	**$ (5)**	$ (248)	$ (83)

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(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion s Consolidated Statements of Income.
(2) Amounts recorded in Dominion s Consolidated Statements of Income are classified in interest and related charges.

VIRGINIA POWER

Balance Sheet Presentation

The tables below present Virginia Power s derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2015			December 31, 2014		
(millions)	**Gross Amounts of Recognized Assets**	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Interest rate contracts:						
Over-the-counter	**$ 13**	**$**	**$ 13**	$	$	$
Commodity contracts:						
Over-the-counter	**101**		**101**	106		106
Total derivatives, subject to a master netting or similar arrangement	**114**		**114**	106		106
Total derivatives, not subject to a master netting or similar arrangement	**13**		**13**	7		7
Total	**$ 127**	**$**	**$ 127**	$ 113	$	$ 113

		December 31, 2015 Gross Amounts Not Offset in the Consolidated Balance Sheet				December 31, 2014 Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ 13**	**$ 10**	**$**	**$ 3**	$	$	$	$
Commodity contracts:								
Over-the-counter	**101**	**3**		**98**	106	4		102
Total	**$ 114**	**$ 13**	**$**	**$ 101**	$ 106	$ 4	$	$ 102

	December 31, 2015			December 31, 2014		
	Gross Amounts of	**Gross Amounts Offset in the**	**Net Amounts of Liabilities Presented in the**	Gross Amounts of	Gross Amounts Offset in the	Net Amounts of Liabilities Presented in the

(millions)	**Recognized Liabilities**	**Consolidated Balance Sheet**	**Consolidated Balance Sheet**	Recognized Liabilities	Consolidated Balance Sheet	Consolidated Balance Sheet
Interest rate contracts:						
Over-the-counter	**$ 59**	**$**	**$ 59**	$ 72	$	$ 72
Commodity contracts:						
Over-the-counter	**5**		**5**	8		8
Total derivatives, subject to a master netting or similar arrangement	**64**		**64**	80		80
Total derivatives, not subject to a master netting or similar arrangement	**22**		**22**	7		7
Total	**$ 86**	**$**	**$ 86**	$ 87	$	$ 87

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Combined Notes to Consolidated Financial Statements, Continued

	December 31, 2015				December 31, 2014			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Net Amounts of Liabilities Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Paid**	**Net Amounts**	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ 59**	**$ 10**	**$**	**$ 49**	$ 72	$	$	$ 72
Commodity contracts:								
Over-the-counter	**5**	**3**		**2**	8	4		4
Total	**$ 64**	**$ 13**	**$**	**$ 51**	$ 80	$ 4	$	$ 76

Volumes

The following table presents the volume of Virginia Power s derivative activity at December 31, 2015. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	**32**	**10**
Basis	**102**	**509**
Electricity (MWh):		
FTRs	**30,383,934**	
Capacity (MW)	**7,600**	
Interest rate	**$ 900,000,000**	**$ 1,100,000,000**

(1) Includes options.

Ineffectiveness

For the years ended December 31, 2015, 2014 and 2013, gains or losses on hedging instruments determined to be ineffective were not material.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Virginia Power s derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)		Fair Value - Derivatives under Hedge Accounting		Fair Value - Derivatives not under Hedge Accounting		Total Fair Value
At December 31, 2015						
ASSETS						
Current Assets						
Commodity	**$**		**$**	**18**	**$**	**18**
Total current derivative assets[1]				**18**		**18**
Noncurrent Assets						
Commodity				**96**		**96**
Interest rate		**13**				**13**
Total noncurrent derivative assets[2]		**13**		**96**		**109**
Total derivative assets	**$**	**13**	**$**	**114**	**$**	**127**
LIABILITIES						
Current Liabilities						
Commodity	**$**		**$**	**23**	**$**	**23**
Interest rate		**57**				**57**
Total current derivative liabilities		**57**		**23**		**80**
Noncurrent Liabilities						
Commodity				**4**		**4**
Interest rate		**2**				**2**
Total noncurrent derivative liabilities[3]		**2**		**4**		**6**
Total derivative liabilities	**$**	**59**	**$**	**27**	**$**	**86**
At December 31, 2014						
ASSETS						
Current Assets						
Commodity	$		$	51	$	51
Total current derivative assets[1]				51		51
Noncurrent Assets						
Commodity				62	$	62
Total noncurrent derivative assets[2]				62		62
Total derivative assets	$		$	113	$	113
LIABILITIES						
Current Liabilities						
Commodity	$	3	$	12	$	15
Interest rate		45				45
Total current derivative liabilities		48		12		60
Noncurrent Liabilities						
Interest rate		27				27
Total noncurrent derivative liabilities[3]		27				27
Total derivative liabilities	$	75	$	12	$	87

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(1) Current derivative assets are presented in other current assets in Virginia Power s Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Virginia Power s Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Virginia Power s Consolidated Balance Sheets.

The following tables present the gains and losses on Virginia Power s derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)[1]	Amount of Gain (Loss) Reclassified from AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment[2]
Year Ended December 31, 2015			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		**$ (1)**	
Total commodity	**$**	**$ (1)**	**$ 4**
Interest rate[3]	**(3)**		**(13)**
Total	**$ (3)**	**$ (1)**	**$ (9)**
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ 5	
Total commodity	$ 4	$ 5	$ (4)
Interest rate[3]	(10)		(81)
Total	$ (6)	$ 5	$ (85)
Year Ended December 31, 2013			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$	
Total commodity	$	$	$ 5
Interest rate[3]	9		81
Total	$ 9	$	$ 86

(1) Amounts deferred into AOCI have no associated effect in Virginia Power s Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power s Consolidated Statements of Income.
(3) Amounts recorded in Virginia Power s Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives[1]		
Year Ended December 31, (millions)	**2015**	2014	2013
Derivative Type and Location of Gains (Losses)			
Commodity[2]	**$ (13)**	$ 105	$ (16)

Total	**$ (13)**	$ 105	$ (16)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power s Consolidated Statements of Income.
(2) Amounts recorded in Virginia Power s Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

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Combined Notes to Consolidated Financial Statements, Continued

DOMINION GAS

Balance Sheet Presentation

The tables below present Dominion Gas derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2015			December 31, 2014		
(millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 11	$	$ 11	$ 2	$	$ 2
Total derivatives, subject to a master netting or similar arrangement	$ 11	$	$ 11	$ 2	$	$ 2

	December 31, 2015				December 31, 2014			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Commodity contracts:								
Over-the-counter	$ 11	$	$	$ 11	$ 2	$	$	$ 2
Total	$ 11	$	$	$ 11	$ 2	$	$	$ 2

	December 31, 2015			December 31, 2014		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance	Net Amounts of Liabilities Presented in	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance	Net Amounts of Liabilities Presented in

		Sheet	**the Consolidated Balance Sheet**		Sheet	the Consolidated Balance Sheet
(millions)						
Interest rate contracts:						
Over-the-counter	**$ 14**	**$**	**$ 14**	$ 9	$	$ 9
Total derivatives, subject to a master netting or similar arrangement	**$ 14**	**$**	**$ 14**	$ 9	$	$ 9

		December 31, 2015				December 31, 2014		
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	**Financial Instruments**	**Cash Collateral Paid**	**Net Amounts**	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
(millions)								
Interest rate contracts:								
Over-the-counter	**$ 14**	**$**	**$**	**$ 14**	$ 9	$	$	$ 9
Total	**$ 14**	**$**	**$**	**$ 14**	$ 9	$	$	$ 9

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Volumes

The following table presents the volume of Dominion Gas derivative activity at December 31, 2015. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
NGLs (Gal)	**77,364,000**	**13,818,000**
Interest rate	**$ 250,000,000**	**$**

Ineffectiveness and AOCI

For the years ended December 31, 2015, 2014 and 2013, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Gas Consolidated Balance Sheet at December 31, 2015:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
NGLs	**$ 7**	**$ 6**	**15 months**
Interest rate	**(24)**		**348 months**
Total	**$ (17)**	**$ 6**	

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 and interest rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Gas derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge	Fair Value - Derivatives not under Hedge	Total Fair Value

(millions)	Accounting		Accounting		
At December 31, 2015					
ASSETS					
Current Assets					
Commodity	**$**	**10**	**$**	**$**	**10**
Total current derivative assets(1)		**10**			**10**
Noncurrent Assets					
Commodity		**1**			**1**
Total noncurrent derivative assets(2)		**1**			**1**
Total derivative assets	**$**	**11**	**$**	**$**	**11**
LIABILITIES					
Current Liabilities					
Interest rate	**$**	**14**	**$**	**$**	**14**
Total current derivative liabilities(3)		**14**			**14**
Total derivative liabilities	**$**	**14**	**$**	**$**	**14**
At December 31, 2014					
ASSETS					
Current Assets					
Commodity	$	2	$	$	2
Total current derivative assets(1)		2			2
Total derivative assets	$	2	$	$	2
LIABILITIES					
Noncurrent Liabilities					
Interest rate	$	9	$	$	9
Total noncurrent derivative liabilities(4)		9			9
Total derivative liabilities	$	9	$	$	9

(1) Current derivative assets are presented in other current assets in Dominion Gas Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Gas Consolidated Balance Sheets.
(3) Current derivative liabilities are presented in other current liabilities in Dominion Gas Consolidated Balance Sheets.
(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Gas Consolidated Balance Sheets.

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Combined Notes to Consolidated Financial Statements, Continued

The following tables present the gains and losses on Dominion Gas derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)[1]	Amount of Gain (Loss) Reclassified from AOCI to Income
Year Ended December 31, 2015		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		**$ 6**
Total commodity	**$ 16**	**$ 6**
Interest rate[2]	**(6)**	
Total	**$ 10**	**$ 6**
Year Ended December 31, 2014		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		$ 2
Purchased gas		(14)
Total commodity	$ 12	$ (12)
Interest rate[2]	(62)	(1)
Total	$ (50)	$ (13)
Year Ended December 31, 2013		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		$ (2)
Purchased gas		(14)
Total commodity	$ (2)	$ (16)
Interest rate[2]	68	
Total	$ 66	$ (16)

(1) Amounts deferred into AOCI have no associated effect in Dominion Gas Consolidated Statements of Income.
(2) Amounts recorded in Dominion Gas Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives

Year Ended December 31,	2015	2014	2013
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity			
Operating revenue	**$ 6**	$	$
Total	**$ 6**	$	$

NOTE 8. EARNINGS PER SHARE

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

	2015	2014	2013
(millions, except EPS)			
Net income attributable to Dominion	**$ 1,899**	$ 1,310	$ 1,697
Average shares of common stock outstanding-Basic	**592.4**	582.7	578.7
Net effect of dilutive securities(1)	**1.3**	1.8	0.8
Average shares of common stock outstanding-Diluted	**593.7**	584.5	579.5
Earnings Per Common Share-Basic	**$ 3.21**	$ 2.25	$ 2.93
Earnings Per Common Share-Diluted	**$ 3.20**	$ 2.24	$ 2.93

(1) Dilutive securities consist primarily of the 2013 Equity Units for 2015, the 2013 Equity Units and contingently convertible senior notes for 2014, and contingently convertible senior notes for 2013. Dominion redeemed all of its contingently convertible senior notes in 2014. See Note 17 for more information.

The 2014 Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the year ended December 31, 2015 as inclusion would have been antidilutive. The 2014 Equity Units were excluded from the calculation of diluted EPS for the year ended December 31, 2014, as the dilutive stock price threshold was not met. The 2013 Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the year ended December 31, 2013. See Note 17 for more information.

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Note 9. Investments

Dominion

Equity and Debt Securities

Rabbi Trust Securities

Marketable equity and debt securities and cash equivalents held in Dominion s rabbi trusts and classified as trading totaled $100 million and $110 million at December 31, 2015 and 2014, respectively.

Decommissioning Trust Securities

Dominion holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Dominion s decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains[1]	Total Unrealized Losses[1]	Fair Value
At December 31, 2015				
Marketable equity securities:				
U.S. large cap	**$ 1,295**	**$ 1,213**	**$**	**$ 2,508**
REIT	**59**	**4**		**63**
Marketable debt securities:				
Corporate debt instruments	**433**	**11**	**(7)**	**437**
U.S. Treasury securities and agency debentures	**654**	**8**	**(4)**	**658**
State and municipal	**312**	**22**		**334**
Other	**99**			**99**
Cost method investments	**70**			**70**
Cash equivalents and other[2]	**14**			**14**
Total	**$ 2,936**	**$ 1,258**	**$ (11)[3]**	**$ 4,183**
At December 31, 2014				
Marketable equity securities:				
U.S. large cap	$ 1,273	$ 1,353	$	$ 2,626
Marketable debt securities:				
Corporate debt instruments	424	19	(2)	441
U.S. Treasury securities and agency debentures	597	13	(4)	606
State and municipal	332	23		355
Other	66			66
Cost method investments	86			86
Cash equivalents and other[2]	16			16
Total	$ 2,794	$ 1,408	$ (6)[3]	$ 4,196

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $12 million and $3 million at December 31, 2015 and 2014, respectively.
(3) The fair value of securities in an unrealized loss position was $592 million and $379 million at December 31, 2015 and 2014, respectively.

The fair value of Dominion s marketable debt securities held in nuclear decommissioning trust funds at December 31, 2015 by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 208**
Due after one year through five years	**396**
Due after five years through ten years	**412**
Due after ten years	**512**
Total	**$ 1,528**

Presented below is selected information regarding Dominion s marketable equity and debt securities held in nuclear decommissioning trust funds:

Year Ended December 31,	2015	2014	2013
(millions)			
Proceeds from sales	**$ 1,340**	$ 1,235	$ 1,476
Realized gains[1]	**219**	171	157
Realized losses[1]	**84**	30	33

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

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Combined Notes to Consolidated Financial Statements, Continued

Dominion recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31, (millions)	**2015**	2014	2013
Total other-than-temporary impairment losses[1]	**$ 66**	$ 21	$ 31
Losses recorded to nuclear decommissioning trust regulatory liability	**(26)**	(5)	(13)
Losses recognized in other comprehensive income (before taxes)	**(9)**	(3)	(10)
Net impairment losses recognized in earnings	**$ 31**	$ 13	$ 8

(1) Amounts include other-than-temporary impairment losses for debt securities of $9 million, $3 million and $18 million at December 31, 2015, 2014 and 2013, respectively.

Virginia Power

Virginia Power holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Virginia Power s decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains[1]	Total Unrealized Losses[1]	Fair Value
At December 31, 2015				
Marketable equity securities:				
U.S. large cap	**$ 574**	**$ 525**	**$**	**$ 1,099**
REIT	**59**	**4**		**63**
Marketable debt securities:				
Corporate debt instruments	**237**	**5**	**(4)**	**238**
U.S. Treasury securities and agency debentures	**260**	**1**	**(2)**	**259**
State and municipal	**162**	**13**	**(1)**	**174**
Other	**34**			**34**
Cost method investments	**70**			**70**
Cash equivalents and other[2]	**8**			**8**
Total	**$ 1,404**	**$ 548**	**$ (7)[3]**	**$ 1,945**
At December 31, 2014				
Marketable equity securities:				
U.S. large cap	$ 563	$ 594	$	$ 1,157
Marketable debt securities:				
Corporate debt instruments	242	9	(1)	250
U.S. Treasury securities and agency debentures	197	3	(2)	198
State and municipal	197	13		210
Other	23			23
Cost method investments	86			86

Cash equivalents and other[2]	6			6
Total	$ 1,314	$ 619	$ (3)[3]	$ 1,930

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $8 million and $6 million at December 31, 2015 and 2014, respectively.
(3) The fair value of securities in an unrealized loss position was $281 million and $170 million at December 31, 2015 and 2014, respectively.

The fair value of Virginia Power s marketable debt securities at December 31, 2015, by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 67**
Due after one year through five years	**166**
Due after five years through ten years	**236**
Due after ten years	**236**
Total	**$ 705**

Presented below is selected information regarding Virginia Power s marketable equity and debt securities held in nuclear decommissioning trust funds.

Year Ended December 31,	**2015**	2014	2013
(millions)			
Proceeds from sales	**$ 639**	$ 549	$ 572
Realized gains[1]	**110**	73	52
Realized losses[1]	**43**	12	14

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Virginia Power recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	**2015**	2014	2013
(millions)			
Total other-than-temporary impairment losses[1]	**$ 36**	$ 8	$ 15
Losses recorded to nuclear decommissioning trust regulatory liability	**(26)**	(4)	(13)
Losses recorded in other comprehensive income (before taxes)	**(6)**	(2)	(1)
Net impairment losses recognized in earnings	**$ 4**	$ 2	$ 1

(1) Amounts include other-than-temporary impairment losses for debt securities of $6 million, $2 million and $9 million at December 31, 2015, 2014 and 2013, respectively.

Equity Method Investments

Dominion and Dominion Gas

Investments that Dominion and Dominion Gas account for under the equity method of accounting are as follows:

Company	Ownership%	Investment Balance		Description
As of December 31,		**2015**	2014	
(millions)				
Dominion				
Blue Racer	50%	**$ 661**	$ 671	Midstream gas and related services

Iroquois	50.65%(1)	**324**	107	Gas transmission system
Fowler Ridge	50%	**125**	134	Wind-powered merchant generation facility
NedPower	50%	**119**	128	Wind-powered merchant generation facility
Atlantic Coast Pipeline	45%	**59**	19	Gas transmission system
Other(2)	various	**32**	22	
Total		**$ 1,320**	$ 1,081	
Dominion Gas				
Iroquois	24.72%	**$ 102**	$ 107	Gas transmission system
Total		**$ 102**	$ 107	

(1) Comprised of Dominion Midstream s interest of 25.93% and Dominion Gas interest of 24.72%. See Note 15 for more information.
(2) Dominion has a $50 million commitment to invest in clean power and technology businesses through 2018.

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Dominion s equity earnings on its investments totaled $56 million, $46 million and $14 million in 2015, 2014 and 2013, respectively. Dominion received distributions from these investments of $83 million, $60 million and $33 million in 2015, 2014, and 2013, respectively. As of December 31, 2015 and 2014, the carrying amount of Dominion s investments exceeded its share of underlying equity in net assets by $234 million and $126 million, respectively. These differences are comprised at December 31, 2015 and 2014, of $72 million and $87 million, respectively, related to basis differences from Dominion s investments in Blue Racer and wind projects, which are being amortized over the useful lives of the underlying assets, and $162 million and $39 million, respectively, reflecting equity method goodwill that is not being amortized.

Dominion Gas equity earnings on its investment totaled $23 million, $21 million and $22 million in 2015, 2014 and 2013, respectively. Dominion Gas received distributions from its investment of $28 million, $20 million and $19 million in 2015, 2014, and 2013, respectively. As of December 31, 2015 and 2014, the carrying amount of Dominion Gas investment exceeded its share of underlying equity in net assets by $8 million. The difference reflects equity method goodwill and is not being amortized.

Equity earnings are recorded in other income in Dominion s and Dominion Gas Consolidated Statements of Income.

Blue Racer

In December 2012, Dominion formed a joint venture with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion and Caiman, with Dominion contributing midstream assets and Caiman contributing private equity capital.

In March 2013, Dominion Gas sold Line TL-404 to an affiliate, that subsequently sold line TL-404 to Blue Racer for cash proceeds of $47 million. The sale resulted in a gain of $25 million ($14 million after-tax) net of a $2 million write-off of goodwill, and is included in other operations and maintenance expense in both Dominion Gas and Dominion s Consolidated Statement of Income.

Phase 1 of Natrium was completed in the second quarter of 2013 and was contributed by Dominion to Blue Racer in the third quarter of 2013, resulting in an increased equity method investment in Blue Racer of $473 million. Also in the third quarter of 2013, Dominion Gas sold Line TPL-2A to an affiliate, that subsequently sold Line TPL-2A to Blue Racer, and sold Line TL-388 to Blue Racer and received $78 million in cash proceeds. The sales resulted in a $74 million ($41 million after-tax) gain which is included in other operations and maintenance expense in both Dominion Gas and Dominion s Consolidated Statements of Income.

In the fourth quarter of 2013, Dominion Gas sold the Western System to an affiliate, that subsequently sold the Western System to Blue Racer for cash proceeds of $30 million. The sale resulted in a gain of $3 million ($2 million after-tax) for Dominion Gas and $4 million ($2 million after-tax) for Dominion and is included in other operations and maintenance expense in both Dominion Gas and Dominion s Consolidated Statement of Income.

Dominion NGL Pipelines, LLC was contributed in January 2014 by Dominion to Blue Racer, prior to commencement of service, resulting in an increased equity method investment of $155 million, including $6 million of goodwill allocated from Dominion s goodwill balance to its equity method investment in Blue Racer.

In March 2014, Dominion Gas sold the Northern System to an affiliate, that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Gas consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion s consideration consisted of cash proceeds of $84 million. The sale resulted in a gain of $59 million ($35 million after-tax for Dominion Gas and $34 million after-tax for Dominion) net of a $3 million write-off of goodwill, and is included in other operations and maintenance expense in both Dominion Gas and Dominion s Consolidated Statements of Income.

Dominion

Atlantic Coast Pipeline

In September 2014, Dominion, along with Duke Energy, Piedmont and AGL, announced the formation of Atlantic Coast Pipeline. The members, which are subsidiaries of the above-referenced parent companies, hold the following membership interests: Dominion, 45%; Duke Energy, 40%; Piedmont, 10%; and AGL, 5%. In October 2015, Duke Energy entered into a merger agreement with Piedmont. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina. Subsidiaries and affiliates of all four members plan to be customers of the pipeline under 20-year contracts. Public Service Company of North Carolina, Inc. also plans to be a customer of the pipeline under a 20-year contract. Atlantic Coast Pipeline is considered an equity method investment as Dominion has the ability to exercise significant influence, but not control, over the investee. See Note 15 for more information.

Combined Notes to Consolidated Financial Statements, Continued

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

Major classes of property, plant and equipment and their respective balances for the Companies are as follows:

At December 31, (millions)	**2015**	2014
Dominion		
Utility:		
Generation	**$ 15,656**	$ 15,193
Transmission	**11,461**	9,897
Distribution	**13,128**	12,354
Storage	**2,460**	2,350
Nuclear fuel	**1,464**	1,411
Gas gathering and processing	**799**	791
General and other	**927**	845
Other-including plant under construction	**5,550**	3,633
Total utility	**51,445**	46,474
Nonutility:		
Merchant generation-nuclear	**1,339**	1,267
Merchant generation-other	**2,683**	2,023
Nuclear fuel	**938**	860
Other-including plant under construction	**1,371**	782
Total nonutility	**6,331**	4,932
Total property, plant and equipment	**$ 57,776**	$ 51,406
Virginia Power		
Utility:		
Generation	**$ 15,656**	$ 15,193
Transmission	**6,963**	5,884
Distribution	**10,048**	9,526
Nuclear fuel	**1,464**	1,411
General and other	**709**	697
Other-including plant under construction	**2,793**	2,464
Total utility	**37,633**	35,175
Nonutility-other	**6**	5
Total property, plant and equipment	**$ 37,639**	$ 35,180
Dominion Gas		
Utility:		
Transmission	**$ 3,804**	$ 3,690
Distribution	**2,765**	2,530
Storage	**1,583**	1,466
Gas gathering and processing	**797**	786
General and other	**165**	111
Plant under construction	**443**	179
Total utility	**9,557**	8,762
Nonutility:		
E&P properties being amortized and other	**136**	140
Total nonutility	**136**	140
Total property, plant and equipment	**$ 9,693**	$ 8,902

There were no significant E&P properties under development, as defined by the SEC, excluded from Dominion Gas amortization at December 31, 2015. 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.

In 2015, Dominion Gas recorded a ceiling test impairment charge of $16 million ($10 million after-tax) in other operations and maintenance expense in its Consolidated Statement of Income. Dominion sold substantially all its Appalachian E&P

properties in April 2010, retaining only wells in and around DTI s storage facilities. The net book basis of the remaining properties as of December 31, 2015 is $14 million.

Jointly-Owned Power Stations

Dominion s and Virginia Power s proportionate share of jointly-owned power stations at December 31, 2015 is as follows:

(millions, except percentages)	Bath County Pumped Storage Station(1)	North Anna Units 1 and 2(1)	Clover Power Station(1)	Millstone Unit 3(2)
Ownership interest	**60%**	**88.4%**	**50%**	**93.5%**
Plant in service	**$ 1,049**	**$ 2,452**	**$ 576**	**$ 1,149**
Accumulated depreciation	**(567)**	**(1,177)**	**(214)**	**(320)**
Nuclear fuel		**621**		**521**
Accumulated amortization of nuclear fuel		**(502)**		**(364)**
Plant under construction	**12**	**116**	**16**	**55**

(1) Units jointly owned by Virginia Power.
(2) Unit jointly owned by Dominion.

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. Dominion and Virginia Power report their share of operating costs in the appropriate operating expense (electric fuel and other energy-related purchases, other operations and maintenance, depreciation, depletion and amortization and other taxes, etc.) in the Consolidated Statements of Income.

Assignments of Shale Development Rights

In December 2013, Dominion Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several of its natural gas storage fields. The agreements provide for payments to Dominion Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from the acreage. In 2013, Dominion Gas received approximately $100 million in cash proceeds, resulting in a $20 million ($12 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas Consolidated Statements of Income. In 2014, Dominion Gas received $16 million in additional cash proceeds resulting from post-closing adjustments. At December 31, 2014, deferred revenue totaled $85 million. In March 2015, Dominion Gas and one of the natural gas producers closed on an amendment to the agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million ($27 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Gas Consolidated Statements of Income. At December 31, 2015, deferred revenue totaled $37 million, which is expected to be recognized over the remaining term of the agreement.

In November 2014, Dominion Gas closed an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provides for payments to Dominion Gas, subject to customary adjustments, of approx-

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imately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In November 2014, Dominion Gas closed on the agreement and received proceeds of $60 million associated with an initial conveyance of approximately 12,000 acres, resulting in a $60 million ($36 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas Consolidated Statements of Income.

In March 2015, Dominion Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $27 million ($16 million after-tax) gain, included in other operations and maintenance expense in Dominion Gas Consolidated Statements of Income.

In September 2015, Dominion Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage. In September 2015, Dominion Gas received proceeds of $52 million associated with the conveyance of the acreage, resulting in a $52 million ($29 million after-tax) gain, included in other operations and maintenance expense in Dominion Gas Consolidated Statements of Income.

NOTE 11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in Dominion s and Dominion Gas carrying amount and segment allocation of goodwill are presented below:

(millions)	Dominion Generation	Dominion Energy	DVP	Corporate and Other[1]	Total
Dominion					
Balance at December 31, 2013[2]	$ 1,454[3]	$ 706[3]	$ 926	$	$ 3,086
Asset disposition adjustment	(32)[4]	(10)[5]			(42)
Balance at December 31, 2014[2]	$ 1,422[3]	$ 696[3]	$ 926	$	$ 3,044
DCG acquisition		**250**			**250**
Balance at December 31, 2015[2]	**$ 1,422**	**$ 946**	**$ 926**	**$**	**$ 3,294**
Dominion Gas					
Balance at December 31, 2013[2]	$	$ 545	$	$	$ 545
Asset disposition adjustment		(3)[5]			(3)
Balance at December 31, 2014[2]	$	$ 542	$	$	$ 542
No events affecting goodwill					
Balance at December 31, 2015[2]	**$**	**$ 542**	**$**	**$**	**$ 542**

(1) Goodwill recorded at the Corporate and Other segment is allocated to the primary operating segments for goodwill impairment testing purposes.
(2) Goodwill amounts do not contain any accumulated impairment losses.
(3) Recast to reflect nonregulated retail energy marketing operations in the Dominion Energy segment.
(4) See Note 3 for a discussion of Dominion s dispositions and related goodwill write-offs.
(5) Related to assets sold or contributed to an affiliate or Blue Racer.

Other Intangible Assets

The Companies other intangible assets are subject to amortization over their estimated useful lives. Dominion s amortization expense for intangible assets was $78 million, $71 million and $72 million for 2015, 2014 and 2013, respectively. In 2015, Dominion acquired $78 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 8 years. Amortization expense for Virginia Power s intangible assets was $25 million, $24 million and $22 million for 2015, 2014 and 2013, respectively. In 2015, Virginia Power acquired $34 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of 6 years. Dominion Gas amortization expense for intangible assets was $18 million, $17 million and $16 million for 2015, 2014 and 2013, respectively. In 2015, Dominion Gas acquired $24 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 14 years. The components of intangible assets are as follows:

At December 31,		**2015**		2014
(millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Dominion				
Software, licenses and other	**$ 942**	**$ 372**	$ 887	$ 317
Total	**$ 942**	**$ 372**	$ 887	$ 317
Virginia Power				
Software, licenses and other	**$ 301**	**$ 88**	$ 286	$ 81
Total	**$ 301**	**$ 88**	$ 286	$ 81
Dominion Gas				
Software, licenses and other	**$ 211**	**$ 128**	$ 192	$ 113
Total	**$ 211**	**$ 128**	$ 192	$ 113

Annual amortization expense for these intangible assets is estimated to be as follows:

(millions)	2016	2017	2018	2019	2020
Dominion	**$ 79**	**$ 68**	**$ 57**	**$ 47**	**$ 35**
Virginia Power	**$ 25**	**$ 22**	**$ 19**	**$ 15**	**$ 9**
Dominion Gas	**$ 18**	**$ 15**	**$ 14**	**$ 13**	**$ 13**

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Combined Notes to Consolidated Financial Statements, Continued

NOTE 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities include the following:

At December 31, (millions)	2015	2014
Dominion		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	**$ 111**	$ 79
Deferred rate adjustment clause costs(2)	**90**	124
Deferred nuclear refueling outage costs(3)	**75**	44
Unrecovered gas costs(4)	**12**	36
Other	**63**	64
Regulatory assets-current	**351**	347
Unrecognized pension and other postretirement benefit costs(5)	**1,015**	1,050
Deferred rate adjustment clause costs(2)	**295**	250
PJM transmission rates(6)	**192**	
Income taxes recoverable through future rates(7)	**126**	133
Derivatives(8)	**110**	101
Other	**127**	108
Regulatory assets-non-current	**1,865**	1,642
Total regulatory assets	**$ 2,216**	$ 1,989
Regulatory liabilities:		
PIPP(9)	**$ 46**	$ 71
Other	**54**	99
Regulatory liabilities-current(10)	**100**	170
Provision for future cost of removal and AROs(11)	**1,120**	1,072
Nuclear decommissioning trust(12)	**804**	815
Deferred cost of fuel used in electric generation(1)	**97**	6
Derivatives(8)	**79**	
Other	**185**	98
Regulatory liabilities-non-current	**2,285**	1,991
Total regulatory liabilities	**$ 2,385**	$ 2,161
Virginia Power		
Regulatory assets:		
Deferred cost of fuel used in electric generation(1)	**$ 111**	$ 79
Deferred rate adjustment clause costs(2)	**80**	117
Deferred nuclear refueling outage costs(3)	**75**	44
Other	**60**	58
Regulatory assets-current	**326**	298
Deferred rate adjustment clause costs(2)	**213**	179
PJM transmission rates(6)	**192**	
Derivatives(8)	**110**	101
Income taxes recoverable through future rates(7)	**97**	100
Other	**55**	59
Regulatory assets-non-current	**667**	439
Total regulatory assets	**$ 993**	$ 737

Regulatory liabilities:		
Other	**$ 35**	$ 90
Regulatory liabilities-current	**35**	90
Provision for future cost of removal[11]	**890**	852
Nuclear decommissioning trust[12]	**804**	815
Deferred cost of fuel used in electric generation[1]	**97**	6
Derivatives[8]	**79**	
Other	**59**	10
Regulatory liabilities-non-current	**1,929**	1,683
Total regulatory liabilities	**$ 1,964**	$ 1,773

At December 31, (millions)	2015	2014
Dominion Gas		
Regulatory assets:		
Unrecovered gas costs[4]	**$ 11**	$ 29
Deferred rate adjustment clause costs[2]	**10**	7
Other	**2**	2
Regulatory assets-current	**23**	38
Unrecognized pension and other postretirement benefit costs[5]	**282**	242
Deferred rate adjustment clause costs[2]	**82**	71
Income taxes recoverable through future rates[7]	**20**	24
Other	**65**	42
Regulatory assets-non-current	**449**	379
Total regulatory assets	**$ 472**	$ 417
Regulatory liabilities:		
PIPP[9]	**$ 46**	$ 71
Other	**9**	4
Regulatory liabilities-current	**55**	75
Provision for future cost of removal and AROs[11]	**170**	172
Other	**31**	20
Regulatory liabilities-non-current	**201**	192
Total regulatory liabilities	**$ 256**	$ 267

(1) Primarily reflects deferred fuel expenses for the Virginia jurisdiction of Dominion s and Virginia Power s generation operations. See Note 13 for more information.

(2) Reflects deferrals under the electric transmission FERC formula rate and the deferral of costs associated with certain current and prospective rider projects for Virginia Power. Reflects deferrals of costs associated with certain current and prospective rider projects for Dominion Gas. See Note 13 for more information.

(3) Legislation enacted in Virginia in April 2014 requires Virginia Power to defer operation and maintenance costs incurred in connection with the refueling of any nuclear-powered generating plant. These deferred costs will be amortized over the refueling cycle, not to exceed 18 months.

(4) Reflects unrecovered gas costs at regulated gas operations, which are recovered through filings with the applicable regulatory authority.

(5) Represents unrecognized pension and other postretirement employee benefit costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain of Dominion s and Dominion Gas rate-regulated subsidiaries.

(6) Reflects amount related to the PJM transmission cost allocation matter. See Note 13 for more information.

(7) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes.

(8) As discussed under Derivative Instruments in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers.

(9) Under PIPP, eligible customers can make reduced payments based on their ability to pay. The difference between the customer s total bill and the PIPP plan amount is deferred and collected or returned annually under the PIPP rate adjustment clause according to East Ohio tariff provisions. See Note 13 for more information.

(10) Current regulatory liabilities are presented in other current liabilities in Dominion s Consolidated Balance Sheets.

(11) Rates charged to customers by the Companies 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.

(12) Primarily reflects a regulatory liability representing amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of Virginia Power s utility nuclear generation stations, in excess of the related AROs.

At December 31, 2015, $131 million of Dominion s, $100 million of Virginia Power s and $29 million of Dominion Gas regulatory assets represented past expenditures on which they do not currently earn a return. The majority of these expenditures are expected to be recovered within the next two years.

NOTE 13. REGULATORY MATTERS

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, the Companies are involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for the Companies to estimate a range of possible loss. For matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that the Companies are able to estimate a range of possible loss. For regulatory matters for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent the Companies maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on the Companies financial position, liquidity or results of operations.

FERC ELECTRIC

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Dominion s merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Tennessee, Georgia, California and Utah, under Dominion s market-based sales tariffs authorized by FERC. Virginia Power purchases and, under its FERC market-based rate authority, sells electricity in the wholesale market. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power s service territory. Any such sales would be voluntary.

Rates

In April 2008, FERC granted an application for Virginia Power s electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power

to earn a current return on its growing investment in electric transmission infrastructure.

In March 2010, ODEC and North Carolina Electric Membership Corporation filed a complaint with FERC against Virginia Power claiming that $223 million in transmission costs related to specific projects were unjust, unreasonable and unduly discriminatory or preferential and should be excluded from Virginia Power s transmission formula rate. In October 2010, FERC issued an order dismissing the complaint in part and established hearings and settlement procedures on the remaining part of the complaint. In February 2012, Virginia Power submitted to FERC a settlement agreement to resolve all issues set for hearing. The settlement was accepted by FERC in May 2012 and provides for payment by Virginia Power to the transmission customer parties collectively of $250,000 per year for ten years and resolves all matters other than allocation of the incremental cost of certain underground transmission facilities.

In March 2014, FERC issued an order excluding from Virginia Power s transmission rates for wholesale transmission customers located outside Virginia the incremental costs of undergrounding certain transmission line projects. FERC found it is not just and reasonable for non-Virginia wholesale transmission customers to be allocated the incremental costs of undergrounding the facilities because the projects are a direct result of Virginia legislation and Virginia Commission pilot programs intended to benefit the citizens of Virginia. The order is retroactively effective as of March 2010 and will cause the reallocation of the costs charged to wholesale transmission customers with loads outside Virginia to wholesale transmission customers with loads in Virginia. FERC determined that there was not sufficient evidence on the record to determine the magnitude of the underground increment and held a hearing to determine the appropriate amount of undergrounding cost to be allocated to each wholesale transmission customer in Virginia. While Virginia Power cannot predict the outcome of the hearing, it is not expected to have a material effect on results of operations.

PJM Transmission Rates

In April 2007, FERC issued an order regarding its transmission rate design for the allocation of costs among PJM transmission customers, including Virginia Power, for transmission service provided by PJM. For new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a PJM regional rate design where customers pay according to each customer s share of the region s load. For recovery of costs of existing facilities, FERC approved the existing methodology whereby a customer pays the cost of facilities located in the same zone as the customer. A number of parties appealed the order to the U.S. Court of Appeals for the Seventh Circuit.

In August 2009, the court issued its decision affirming the FERC order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above for further consideration by FERC. On remand, FERC reaffirmed its earlier decision to allocate the costs of new facilities 500 kV and above according to the customer s share of the region s load. A number of parties filed appeals of the order to the U.S. Court of Appeals for the Seventh Circuit. In June 2014, the court again remanded the cost allocation issue to FERC. In December 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the cost

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allocation issue. The hearing only concerns the costs of new facilities approved by PJM prior to February 1, 2013. Transmission facilities approved after February 1, 2013 are allocated on a hybrid cost allocation method approved by FERC and not subject to any court review.

Virginia Power expects that a settlement agreement will be executed regarding this matter. Under the terms of the settlement, Virginia Power would be required to pay $200 million to PJM over the next 10 years. Although no FERC order has been issued and the expected settlement agreement has not been filed and accepted by FERC, Virginia Power believes it is probable it will be required to make payment as an outcome of the hearing and settlement proceedings. Accordingly, as of December 31, 2015, Virginia Power has recorded a contingent liability of $200 million in other deferred credits and other liabilities, which is offset by a $192 million regulatory asset for the amount that will be recovered through retail rates in Virginia. The remaining $8 million was recorded in other operations and maintenance expense in the Consolidated Statement of Income.

Other Regulatory Matters

Electric Regulation in Virginia

The Regulation Act enacted in 2007 instituted a cost-of-service rate model, ending Virginia s planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

If the Virginia Commission s future rate decisions, including actions relating to Virginia Power s rate adjustment clause filings, differ materially from Virginia Power s expectations, it may adversely affect its results of operations, financial condition and cash flows.

Regulation Act Legislation

In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power s base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia

Power s 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility s ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. However, in November 2015, the Virginia Commission ordered testimony, briefs and

separate bifurcated hearing in Virginia Power s currently pending Rider B, Rider R, Rider S and Rider W cases on whether the Virginia Commission can adjust the ROE applicable to these rate adjustment clauses prior to 2017. The legislation also required Virginia Power to write-off $85 million of prior-period deferred fuel costs during the first quarter of 2015. In addition, the legislation required the Virginia Commission to implement a fuel rate reduction for Virginia Power as soon as practicable based on this non-recovery as well as any over-recovery for the 2014-2015 fuel year and projected fuel expense for the 2015-2016 fuel year. The legislation also deems the construction or purchase of one or more utility-scale solar facilities located in Virginia up to 500 MW in total to be in the public interest.

2015 Biennial Review

Pursuant to the Regulation Act, in March 2015, Virginia Power filed its base rate case and schedules for the Virginia Commission s 2015 biennial review of Virginia Power s rates, terms and conditions. Per legislation enacted in February 2015, this biennial review was limited to reviewing Virginia Power s earnings on rates for generation and distribution services for the combined 2013 and 2014 test period, and determining whether credits are due to customers in the event Virginia Power s earnings exceeded the earnings band determined in the 2013 Biennial Review Order. In November 2015, the Virginia Commission issued the 2015 Biennial Review Order.

After deciding several contested regulatory earnings adjustments, the Virginia Commission ruled that Virginia Power earned on average an ROE of approximately 10.89% on its generation and distribution services for the combined 2013 and 2014 test periods. Because this ROE was more than 70 basis points above Virginia Power s authorized ROE of 10.0%, the Virginia Commission ordered that approximately $20 million in excess earnings be credited to customer bills based on usage in 2013 and 2014 over a six-month period beginning within 60 days of the 2015 Biennial Review Order. Based upon 2015 legislation keeping Virginia Power s base rates unchanged until at least December 1, 2022, the Virginia Commission did not order certain existing rate adjustment clauses to be combined with Virginia Power s base rates. The Virginia Commission did not determine whether Virginia Power had a revenue deficiency or sufficiency when projecting the annual revenues generated by base rates to the revenues required to recover costs of service and earn a fair return. In December 2015, a group of large industrial customers filed notices of appeal with the Supreme Court of Virginia from both the 2015 Biennial Review Order and the Virginia Commission s order denying their petition for rehearing or reconsideration. This appeal is pending.

Virginia Fuel Expenses

In February 2015, Virginia Power submitted its annual fuel factor filing to the Virginia Commission. In August 2015, the Virginia Commission approved Virginia Power s annual fuel factor filing to recover an estimated $1.6 billion in Virginia jurisdictional projected fuel expenses for the rate year beginning July 1, 2015. Virginia Power s new approved fuel rate, in effect on an interim basis since April 1, 2015, represents a fuel revenue decrease of $512 million when applied to projected kilowatt-hour sales for the period April 1, 2015 to June 30, 2016.

Solar Facility Projects

In January 2015, Virginia Power applied for a CPCN to construct and operate a 20 MW utility-scale solar facility near its existing Remington power station in Fauquier County, Virginia. The total estimated cost of the Remington solar facility was approximately $47 million, excluding financing costs. Virginia Power also applied for approval of Rider US-1 to recover the projected costs of the facility. In October 2015, the Virginia Commission denied approval of the CPCN and Rider US-1 based on the evidence in the record but stated that an application could be re-filed to address the concerns cited by the Virginia Commission. Virginia Power is assessing its options for re-filing.

In October 2015, Virginia Power filed a CPCN with the Virginia Commission to construct three solar facilities. Woodland, Scott Solar and Whitehouse would increase Dominion s renewable generation by a combined 56 MW and are estimated to cost approximately $130 million, excluding financing costs. Virginia Power also applied for approval of Rider US-2. This case is pending. The facilities are expected to commence commercial operations, subject to regulatory approvals, in the fourth quarter of 2016.

Rate Adjustment Clauses

Below is a discussion of significant riders associated with various Virginia Power projects:

- The Virginia Commission previously approved Rider T1 concerning transmission rates. In May 2015, Virginia Power proposed a $668 million total revenue requirement for the rate year beginning September 1, 2015, which represents a $130 million increase over the previous year. Virginia Power also presented a mitigation proposal to defer $96 million of this revenue requirement to the rate year beginning September 1, 2016, which would reduce by 50% the one-year rate impact on residential customers. In August 2015, the Virginia Commission rejected the mitigation proposal and approved full recovery of the proposed revenue requirement.
- The Virginia Commission previously approved Rider S in conjunction with the Virginia City Hybrid Energy Center. In June 2015, Virginia Power proposed a $250 million revenue requirement for the rate year beginning April 1, 2016, which represents a $5 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider W in conjunction with Warren County. In June 2015, Virginia Power proposed a $118 million revenue requirement for the rate year beginning April 1, 2016, which represents a $17 million decrease versus the previous year. This case is pending.
- The Virginia Commission previously approved Rider R in conjunction with Bear Garden. In June 2015, Virginia Power proposed a $74 million revenue requirement for the rate year beginning April 1, 2016, which represents a $10 million decrease versus the previous year. This case is pending.
- The Virginia Commission previously approved Rider B in conjunction with the conversion of three power stations to biomass. In June 2015, Virginia Power proposed a $30 million revenue requirement for the rate year beginning April 1, 2016, which represents a $21 million increase over the previous year. This case is pending.
- Virginia legislation which provides for the recovery of costs to move certain electric distribution facilities underground became effective in July 2014. In October 2014, Virginia Power filed for approval of Rider U, which proposed a revenue requirement of $28 million during the initial rate year beginning September 1, 2015. In May 2015, Virginia Power revised the revenue requirement to $24 million. In July 2015, the Virginia Commission denied approval of Rider U based on the evidence in the record, but found that an alternative plan addressing certain concerns, such as the lack of a cost-benefit analysis, could reasonably satisfy the regulatory requirements for approval. In December 2015, Virginia Power filed for approval of a more limited undergrounding program, along with a revised Rider U proposing a revenue requirement of $24 million for the initial rate year beginning September 1, 2016. This case is pending.
- The Virginia Commission previously approved Riders C1A and C2A in connection with cost recovery for DSM programs. In August 2015, Virginia Power proposed a total revenue requirement of $50 million for the rate year beginning May 1, 2016. Virginia Power further proposed two new energy efficiency programs for Virginia Commission approval with a requested five-year cost cap of $51 million for those programs, and to extend an existing peak-shaving program for an additional five years under current funding. This case is pending.
- The Virginia Commission previously approved Rider BW in conjunction with Brunswick County. In October 2015, Virginia Power proposed a $156 million total revenue requirement for the rate year beginning September 1, 2016, which represents a $45 million increase versus the previous year. This case is pending.
- In July 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate Greensville County and related transmission interconnection facilities. Virginia Power also applied for approval of Rider GV to recover the costs of Greensville County, and proposed a total revenue requirement of $42 million for the rate year beginning April 1, 2016. This case is pending.

Electric Transmission Projects

In November 2013, the Virginia Commission issued an order granting Virginia Power a CPCN to construct approximately 7 miles of new overhead 500 kV transmission line from the existing Surry switching station in Surry County to a new Skiffes Creek switching station in James City County, and approximately 20 miles of new 230 kV transmission line in James City County, York County, and the City of Newport News from the proposed new Skiffes Creek switching station to Virginia Power s existing Whealton substation in the City of Hampton. In February 2014, the Virginia Commission granted reconsideration requested by Virginia Power and issued an Order Amending Certificate. Several appeals were filed with the Supreme Court of Virginia. In April 2015, the Supreme Court of Virginia issued its opinion in the consolidated appeals of the Virginia Commission s order granting a CPCN for the Skiffes Creek transmission line and related facilities. The Supreme Court of Virginia unanimously affirmed all but one of the alleged grounds for appeal. The court approved the proposed project including the proposed route for a

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500 kV overhead transmission line from Surry to the Skiffes Creek switching station site. The court reversed and remanded the Virginia Commission s determination in one set of appeals that the Skiffes Creek switching station was a transmission line for purposes of statutory exemption from local zoning ordinances. In May 2015, the Supreme Court of Virginia denied separate petitions filed by Virginia Power and the Virginia Commission to rehear its ruling regarding the Skiffes Creek switching station. Pending receipt of remaining required permits and approvals, Virginia Power expects to construct the project.

In May 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate in Loudoun County, Virginia, a new approximately 230 kV Poland Road substation, and a new approximately four mile overhead 230 kV double circuit transmission line between the existing 230 kV Loudoun-Brambleton line and the Poland Road substation. The total estimated cost of the project is approximately $55 million. This case is pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to convert an existing transmission line to 230 kV in Prince William County, Virginia, and Loudoun County, Virginia, and to construct and operate a new approximately five mile overhead 230 kV double circuit transmission line between a tap point near the Gainesville substation and a new to-be-constructed Haymarket substation. The total estimated cost of the project is approximately $51 million. This case is pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate in multiple Virginia counties an approximately 38 mile overhead 230 kV transmission line between the Remington and Gordonsville substations, along with associated facilities. The total estimated cost of the project is approximately $104 million. This case is pending.

In February 2016, the Virginia Commission issued an order granting Virginia Power a CPCN to construct and operate the Remington CT-Warrenton 230 kV double circuit transmission line, the Vint Hill-Wheeler and Wheeler-Gainesville 230 kV lines and the 230 kV Vint Hill and Wheeler switching stations along Virginia Power s proposed route. The total estimated cost of the project is approximately $105 million.

North Anna

Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna. If Virginia Power decides to build a new unit, it must first receive a COL from the NRC, approval of the Virginia Commission and certain environmental permits and other approvals. The COL is expected in 2017. Virginia Power has not yet committed to building a new nuclear unit at North Anna.

The motions and petitions filed by BREDL prior to April 2015 have been dismissed, and under a previous ruling of the NRC, the contested portion of the COL proceeding remains terminated. The NRC is required to conduct a hearing in all COL proceedings, and if a new contention is not admitted, the mandatory NRC hearing will be uncontested.

In April 2015, BREDL filed a new motion and petition seeking to object to the NRC s reliance on the continued storage rule in licensing proceedings. The BREDL filings are substantially the

same as those filed in other COL proceedings in which final environmental impact statements were issued prior to promulgation of the continued storage rule, like North Anna 3. In June 2015, the NRC denied the April 2015 motion and petition.

In August 2015, BREDL filed a petition in the U.S. Court of Appeals for the D.C. Circuit seeking review of the NRC s June 2015 decision. Along with the petition for judicial review, BREDL also filed a motion to hold this judicial review in abeyance pending the outcome of the ongoing judicial review of the NRC s rule pertaining to the continued onsite storage of spent nuclear fuel in litigation pending before the same court. Similar petitions were filed seeking judicial review of the NRC s decision as it applies to other COL and license renewal proceedings. Virginia Power has filed a motion with the court to intervene in the proceeding. This case is pending.

North Anna and Offshore Wind Legislation

In April 2014, legislation was enacted in Virginia that permits Virginia Power to recover 70% of the costs previously deferred or capitalized related to the development of a third nuclear unit located at North Anna and offshore wind facilities through December 31, 2013 as part of the 2013 and 2014 base rates. Virginia Power had deferred or capitalized costs totaling $577 million for these projects as of December 31, 2013, substantially all of which relate to North Anna. For the 70% portion of these previously deferred or capitalized costs allocable to customers in Virginia, Virginia Power recognized such amounts as charges against net income beginning in the second quarter of 2014 and for the remainder of the year. During 2014, Virginia Power recognized $374 million ($248 million after-tax) in charges against income representing the cumulative recovery of costs from January 2013 through December 2014, which are primarily included in other operations and maintenance expense in the Consolidated Statements of Income. The remaining deferred or capitalized costs, as well as costs incurred after December 31, 2013, continue to be eligible for inclusion in a future rate adjustment clause.

North Carolina Regulation

In December 2012, the North Carolina Commission approved a $36 million increase in Virginia Power s annual non-fuel base revenues based on an authorized ROE of 10.2%, and a $14 million decrease in annual base fuel revenues for a combined total base revenue increase of $22 million. These rate changes became effective on January 1, 2013. Following an appeal to the Supreme Court of North Carolina, the North Carolina Commission issued an opinion reaffirming its 10.2% ROE determination in July 2015.

In August 2015, Virginia Power submitted its annual filing to the North Carolina Commission to adjust the fuel component of its electric rates. Virginia Power proposed an $11 million decrease to the fuel component of its electric rates for the rate year beginning January 1, 2016. This decrease includes the North Carolina Commission s previous approval to defer recovering 50% of Virginia Power s estimated $17 million jurisdictional deferred fuel balance to the 2016 fuel year, without interest. In December 2015, the North Carolina Commission approved Virginia Power s proposed fuel charge adjustment.

Ohio Regulation

PIR Program

In 2008, East Ohio began PIR, aimed at replacing approximately 25% of its pipeline system. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In its application, East Ohio proposed that PIR investments for 2016 should fall under the existing authorization and that the new five-year period should include investment through December 31, 2021. East Ohio also proposed that the PIR investment should be increased by $20 million in 2017 and another $20 million in 2018, bringing the total annual investment to $200 million. Thereafter, East Ohio proposed capital investment increases of 3% per year for 2019 through 2021 to mitigate inflation and other cost pressures experienced to date, which will continue into the future. This case is pending.

In February 2015, East Ohio filed an application to adjust the PIR cost recovery for 2014 costs. The filing reflects gross plant investment for 2014 of $155 million, cumulative gross plant investment of $829 million and a revenue requirement of $108 million. This application was approved by the Ohio Commission in April 2015.

AMR Program

In 2007, East Ohio began installing automated meter reading technology for its 1.2 million customers in Ohio. The AMR program approved by the Ohio Commission was completed in 2012. Although no further capital investment will be added, East Ohio is approved to recover depreciation, property taxes, carrying charges and a return until East Ohio has another rate case.

In February 2015, East Ohio filed its application with the Ohio Commission to adjust its AMR cost recovery charge to recover costs for calendar year 2014 associated with AMR deployment. The filing reflects a projected revenue requirement of approximately $8 million. This application was approved by the Ohio Commission in April 2015.

PIPP Plus Program

Under the Ohio PIPP Plus Program, eligible customers can make reduced payments based on their ability to pay their bill. The difference between the customer s total bill and the PIPP amount is deferred and collected under the PIPP Rider in accordance with the rules of the Ohio Commission. In July 2015, East Ohio s annual update of the PIPP Rider was automatically approved by the Ohio Commission after a 45-day waiting period from the date of the filing. The revised rider rate reflects the refund for the twelve-month period from July 2015 through June 2016 of an over-recovery of accumulated arrearages of approximately $57 million as of March 31, 2015, net of projected deferred program costs of approximately $35 million from April 2015 through June 2016.

UEX Rider

East Ohio has approval for a UEX Rider through which it recovers the bad debt expense of most customers not participating in the PIPP Plus Program. The UEX Rider is adjusted annually to achieve dollar for dollar recovery of East Ohio s actual write-offs of uncollectible amounts. In July 2015, the Ohio Commission

approved East Ohio s application to decrease its UEX Rider, which reflects a refund of over-recovered accumulated bad debt expense of $14 million as of March 31, 2015, and recovery of prospective net bad debt expense projected to total approximately $20 million for the twelve-month period from April 2015 to March 2016.

PSMP

In October 2015, East Ohio requested approval from the Ohio Commission to defer the operation and maintenance costs associated with implementing a proposed PSMP. The costs are not expected to exceed $15 million per year.

West Virginia Regulation

In September 2015, Hope requested approval of PREP from the West Virginia Commission. In the application, Hope proposed a projected capital investment for 2016 of $24 million as part of a total five-year projected capital investment of $158 million. In January 2016, Hope and the West Virginia Commission reached a settlement allowing Hope to include costs related to capital investment for 2016 of $20 million in new PREP customer rates effective March 1, 2016.

FERC Gas

During the second quarter of 2013, DCG executed binding precedent agreements for the approximately $35 million Edgemoor Project. FERC approved the Edgemoor Project in February 2015, construction commenced in March 2015 and the project was placed into service in December 2015

In April 2014, DCG executed a binding precedent agreement for the approximately $35 million Columbia to Eastover Project. In May 2015, DCG filed an application to request FERC authorization to construct and operate the project facilities, which are expected to be in service in the third quarter of 2016.

In October 2015, Cove Point received authorization to construct the approximately $30 million St. Charles Transportation Project and the approximately $40 million Keys Energy Project. Construction on each project commenced in the fourth quarter of 2015. The St. Charles Transportation Project is anticipated to be placed into service in June 2016. The Keys Energy Project is anticipated to be placed into service in March 2017.

Note 14. Asset Retirement Obligations

AROs represent obligations that result from laws, statutes, contracts and regulations related to the eventual retirement of certain of the Companies long-lived assets. Dominion s and Virginia Power s AROs are primarily associated with the decommissioning of their nuclear generation facilities and also include those for ash pond closures and the future abatement of asbestos expected to be disturbed in their generation facilities. Dominion Gas AROs primarily include plugging and abandonment of gas and oil wells and the interim retirement of natural gas gathering, transmission, distribution and storage pipeline components.

The Companies have also identified, but not recognized, AROs related to the retirement of Dominion s LNG facility, Dominion Gas storage wells in its underground natural gas storage network, certain Virginia Power electric transmission and distribution assets located on property with easements, rights of way, franchises and

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lease agreements, Virginia Power s hydroelectric generation facilities and the abatement of certain asbestos not expected to be disturbed in Dominion s and Virginia Power s generation facilities. The Companies currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets since the economic lives of these assets can be extended indefinitely through regular repair and maintenance and they currently have no plans to retire or dispose of any of these assets. As a result, a settlement date is not determinable for these assets and AROs for these assets will not be reflected in the Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. The Companies continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets. The changes to AROs during 2014 and 2015 were as follows:

(millions)	Amount
Dominion	
AROs at December 31, 2013	$ 1,578
Obligations incurred during the period	40
Obligations settled during the period	(82)
Revisions in estimated cash flows(1)	102
Accretion	81
Other	(5)
AROs at December 31, 2014(2)	$ 1,714
Obligations incurred during the period(3)	**315**
Obligations settled during the period	**(106)**
Revisions in estimated cash flows(3)	**88**
Accretion	**93**
Other	**(1)**
AROs at December 31, 2015(2)	**$ 2,103**
Virginia Power	
AROs at December 31, 2013	$ 689
Obligations incurred during the period	28
Obligations settled during the period	(1)
Revisions in estimated cash flows(1)	108
Accretion	37
Other	(6)
AROs at December 31, 2014	$ 855
Obligations incurred during the period(3)	**289**
Obligations settled during the period	**(39)**
Revisions in estimated cash flows(3)	**92**
Accretion	**50**
AROs at December 31, 2015	**$ 1,247**
Dominion Gas	
AROs at December 31, 2013	$ 137
Obligations incurred during the period	2
Obligations settled during the period	(8)
Accretion	8
Other	8
AROs at December 31, 2014(4)	$ 147
Obligations incurred during the period	**5**
Obligations settled during the period	**(6)**
Revisions in estimated cash flows	**(5)**
Accretion	**9**
Other	**(1)**

AROs at December 31, 2015[4]	**$ 149**

(1) Relates primarily to a shift of the delayed planned date on which the DOE is expected to begin accepting spent nuclear fuel.
(2) Includes $81 million and $216 million reported in other current liabilities at December 31, 2014, and 2015, respectively.
(3) Primarily reflects future ash pond and landfill closure costs at certain utility generation facilities. See Note 22 for further information.
(4) Includes $140 million and $137 million reported in other deferred credits and other liabilities, with the remainder recorded in other current liabilities, at December 31, 2014 and 2015, respectively.

Dominion and Virginia Power have established trusts dedicated to funding the future decommissioning of their nuclear plants. At both December 31, 2015 and 2014, the aggregate fair value of Dominion s trusts, consisting primarily of equity and debt securities, totaled $4.2 billion. At both December 31, 2015 and 2014, the aggregate fair value of Virginia Power s trusts, consisting primarily of debt and equity securities, totaled $1.9 billion.

NOTE 15. VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE is required 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 has both 1) the power to direct the activities that most significantly impact the entity s economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

Dominion

Through August 2013, Dominion leased the Fairless generating facility in Pennsylvania, which began commercial operations in June 2004, from Juniper, the lessor. In August 2013, the lease expired and Dominion purchased Fairless for $923 million from Juniper per the terms of the lease agreement. However, as Dominion had previously consolidated Juniper, the purchase was accounted for as an equity transaction to acquire the noncontrolling interests from Juniper for $923 million, while Dominion retained control of Fairless.

Dominion has an initial 45% membership interest in Atlantic Coast Pipeline. See Note 9 for more details regarding the nature of this entity. Dominion concluded that Atlantic Coast Pipeline is a VIE because it has insufficient equity to finance its activities without additional subordinated financial support. Dominion has concluded that it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance, as the power to direct is shared among multiple unrelated parties. Dominion is obligated to provide capital contributions based on its ownership percentage. Dominion s maximum exposure to loss is limited to its current and future investment.

Dominion and Dominion Gas

Dominion Midstream and Dominion Gas own a 25.93% and 24.72% noncontrolling partnership interest in Iroquois, respectively. See Note 3 for further details regarding the nature of this entity. Dominion concluded that Iroquois is a VIE because a non-affiliated Iroquois equity holder has the ability during a limited period of time to transfer its ownership interests to another Iroquois equity holder or its affiliate. At December 31, 2015, Dominion concluded that neither Dominion Midstream nor Dominion Gas is the primary beneficiary of Iroquois as they do not have the power to direct the activities of Iroquois that most significantly impact its economic performance, as the power to direct is shared among multiple unrelated parties. If Iroquois determines capital contributions are required, Dominion Midstream and Dominion Gas each would be obligated to provide the portion of capital contributions based on its ownership percentage. Dominion Midstream s and Dominion Gas maximum exposure to loss is limited to their current and future investment.

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Dominion Gas

DTI has been engaged to oversee the construction of, and to subsequently operate and maintain, the projects undertaken by Atlantic Coast Pipeline based on the overall direction and oversight of Atlantic Coast Pipeline s members. An affiliate of DTI holds a membership interest in Atlantic Coast Pipeline, therefore DTI is considered to have a variable interest in Atlantic Coast Pipeline. The members of Atlantic Coast Pipeline hold the power to direct the construction, operations and maintenance activities of the entity. DTI has concluded it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance. DTI has no obligation to absorb any losses of the VIE. See Note 24 for information about associated related party receivable balances.

Virginia Power

Virginia Power had long-term power and capacity contracts with five non-utility generators, which contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. Contracts with two of these non-utility generators expired during 2015 leaving a remaining aggregate summer generation capacity of approximately 418 MW. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power s knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power s determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the entities during the remaining terms of Virginia Power s contracts and for the years the entities are expected to operate after its contractual relationships expire. The remaining contracts expire at various dates ranging from 2017 to 2021. Virginia Power is not subject to any risk of loss from these potential VIEs other than its remaining purchase commitments which totaled $439 million as of December 31, 2015. Virginia Power paid $200 million, $223 million, and $217 million for electric capacity and $83 million, $138 million, and $98 million for electric energy to these entities for the years ended December 31, 2015, 2014 and 2013, respectively.

Virginia Power and Dominion Gas

Virginia Power and Dominion Gas purchased shared services from DRS, an affiliated VIE, of $318 million and $115 million, $335 million and $106 million, and $331 million and $115 million for the years ended December 31, 2015, 2014 and 2013, respectively. Virginia Power and Dominion Gas determined that each is not the most closely associated entity with DRS and therefore neither is the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to

all Dominion subsidiaries, including Virginia Power and Dominion Gas. Virginia Power and Dominion Gas have no obligation to absorb more than their allocated shares of DRS costs.

Note 16. Short-term Debt and Credit Agreements

The Companies use short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing 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 January 2016, Dominion expanded its short-term funding resources through a $1.0 billion increase to one of its joint revolving credit facility limits. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion s credit ratings and the credit quality of its counterparties.

Dominion

Commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
At December 31, 2015				
Joint revolving credit facility(1)(2)	**$ 4,000**	**$ 3,353**	**$**	**$ 647**
Joint revolving credit facility(1)	**500**	**156**	**59**	**285**
Total	**$ 4,500**	**$ 3,509(3)**	**$ 59**	**$ 932**
At December 31, 2014				
Joint revolving credit facility(1)	$ 4,000	$ 2,664	$	$ 1,336
Joint revolving credit facility(1)	500	111	48	341
Total	$ 4,500	$ 2,775(3)	$ 48	$ 1,677

(1) These credit facilities mature in April 2019, and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.

(2) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rates of the outstanding commercial paper supported by Dominion s credit facilities were 0.62% and 0.38% at December 31, 2015 and 2014, respectively.

Virginia Power

Virginia Power s short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Combined Notes to Consolidated Financial Statements, Continued

Virginia Power s share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion and Dominion Gas were as follows:

(millions)	Facility Limit (1)	Outstanding Commercial Paper	Outstanding Letters of Credit
At December 31, 2015			
Joint revolving credit facility(1)(2)	**$ 4,000**	**$ 1,500**	**$**
Joint revolving credit facility(1)	**500**	**156**	
Total	**$ 4,500**	**$ 1,656(3)**	**$**
At December 31, 2014			
Joint revolving credit facility(1)	$ 4,000	$ 1,250	$
Joint revolving credit facility(1)	500	111	
Total	$ 4,500	$ 1,361(3)	$

(1) The full amount of the facilities is available to Virginia Power, less any amounts outstanding to co-borrowers Dominion and Dominion Gas. Sub-limits for Virginia Power are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2015, the sub-limit for Virginia Power was an aggregate $1.75 billion. If Virginia Power has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion. These credit facilities mature in April 2019, and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $2.0 billion (or the sub-limit, whichever is less) of letters of credit.

(2) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rates of the outstanding commercial paper supported by these credit facilities were 0.60% and 0.36% at December 31, 2015 and 2014, respectively.

In addition to the credit facility commitments mentioned above, Virginia Power also has a $120 million credit facility with a maturity date of April 2019. As of December 31, 2015, this facility supports $119 million of certain variable rate tax-exempt financings of Virginia Power.

Dominion Gas

Dominion Gas short-term financing is supported by its access as co-borrower to the two joint revolving credit facilities. In December 2014, Dominion Gas entered into a commercial paper program pursuant to which it began accessing the commercial paper markets in January 2015.

Dominion Gas share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion and Virginia Power were as follows:

(millions)	Facility Limit (1)	Outstanding Commercial Paper	Outstanding Letters of Credit
At December 31, 2015			
Joint revolving credit facility(1)	**$ 1,000**	**$ 391**	**$**
Joint revolving credit facility(1)	**500**		
Total	**$ 1,500**	**$ 391(2)**	**$**
At December 31, 2014			

Joint revolving credit facility[(1)]	$	1,000	$		$	
Joint revolving credit facility[(1)]		500				
Total	$	1,500	$		$	

(1) A maximum of a combined $1.5 billion of the facilities is available to Dominion Gas, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion and Virginia Power. Sub-limits for Dominion Gas are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2015, the sub-limit for Dominion Gas was an aggregate $500 million. In January 2016, the aggregate sub-limit for Dominion Gas was increased to $1.0 billion. If Dominion Gas has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion. These credit facilities mature in April 2019, and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion (or the sub-limit, whichever is less) of letters of credit.

(2) The weighted-average interest rate of the outstanding commercial paper supported by these credit facilities was 0.63% at December 31, 2015.

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NOTE 17. LONG-TERM DEBT

At December 31, (millions, except percentages)	2015 Weighted-average Coupon[1]	2015	2014
Dominion Gas Holdings, LLC:			
Unsecured Senior Notes:			
1.05% to 2.8%, due 2016 to 2020	**2.26%**	**$ 1,550**	$ 850
3.55% to 4.8%, due 2023 to 2044	**4.15%**	**1,750**	1,750
Dominion Gas Holdings, LLC total principal		**$ 3,300**	$ 2,600
Securities due within one year	**1.05%**	**(400)**	
Unamortized discount		**(8)**	(6)
Dominion Gas Holdings, LLC total long-term debt		**$ 2,892**	$ 2,594
Virginia Electric and Power Company:			
Unsecured Senior Notes:			
1.2% to 8.625%, due 2015 to 2019	**5.03%**	**$ 2,261**	$ 2,471
2.75% to 8.875%, due 2022 to 2045	**4.91%**	**6,292**	5,592
Tax-Exempt Financings[2]:			
Variable rates, due 2016 to 2041	**0.79%**	**194**	606
0.70% to 5.6%, due 2023 to 2041	**2.19%**	**678**	266
Virginia Electric and Power Company total principal		**$ 9,425**	$ 8,935
Securities due within one year	**5.24%**	**(476)**	(211)
Unamortized discount and premium, net			2
Virginia Electric and Power Company total long-term debt		**$ 8,949**	$ 8,726
Dominion Resources, Inc.:			
Unsecured Senior Notes:			
Variable rates, due 2015 and 2016	**1.11%**	**$ 600**	$ 400
1.25% to 6.4%, due 2015 to 2019	**3.05%**	**3,400**	3,150
2.75% to 7.0%, due 2021 to 2044[3]	**4.80%**	**5,099**	4,449
Tax-Exempt Financing, variable rate, due 2041	**1.16%**	**75**	75
Unsecured Junior Subordinated Notes Payable to Affiliated Trust, 8.4%, due 2031	**8.40%**	**10**	10
Enhanced Junior Subordinated Notes:			
5.75% and 7.5%, due 2054 and 2066	**6.27%**	**971**	985
Variable rate, due 2066	**2.90%**	**377**	380
Remarketable Subordinated Notes, 1.07% to 1.50%, due 2019 to 2021	**1.30%**	**2,100**	2,100
Unsecured Debentures and Senior Notes[4]:			
6.8% and 6.875%, due 2026 and 2027	**6.81%**	**89**	89
Dominion Energy, Inc.:			
Tax-Exempt Financing, 2.375%, due 2033	**2.38%**	**27**	27
Dominion Gas Holdings, LLC total principal (from above)		**3,300**	2,600
Virginia Electric and Power Company total principal (from above)		**9,425**	8,935
Dominion Resources, Inc. total principal		**$ 25,473**	$ 23,200
Fair value hedge valuation[5]		**7**	19
Securities due within one year[6]	**2.38%**	**(1,826)**	(1,375)
Unamortized discount and premium, net		**(38)**	(39)
Dominion Resources, Inc. total long-term debt		**$ 23,616**	$ 21,805

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2015.
(2)

These financings relate to certain pollution control equipment at Virginia Power s generating facilities. Certain variable rate tax-exempt financings are supported by a $120 million credit facility that terminates in April 2019.

(3) At the option of holders, $510 million of Dominion s 5.25% senior notes due 2033 were subject to redemption at 100% of the principal amount plus accrued interest in August 2015. As a result, at December 31, 2014, the notes were included in securities due within one year in Dominion s Consolidated Balance Sheets. The option to redeem the notes expired in June 2015. At December 31, 2015, the notes are included in long-term debt in Dominion s Consolidated Balance Sheets.

(4) Represents debt assumed by Dominion from the merger of its former CNG subsidiary.

(5) Represents the valuation of certain fair value hedges associated with Dominion s fixed rate debt.

(6) Includes $4 million for fair value hedge valuation in 2014. Excludes $100 million of variable rate short-term notes scheduled to mature in May 2016 that were purchased and cancelled using the proceeds from the February 2016 issuance of senior notes that mature in 2018.

Combined Notes to Consolidated Financial Statements, Continued

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2015, were as follows:

	2016	2017	2018	2019	2020	Thereafter	Total
(millions, except percentages)							
Dominion Gas	**$ 400**	**$**	**$**	**$ 450**	**$ 700**	**$ 1,750**	**$ 3,300**
Weighted-average Coupon	**1.05%**			**2.50%**	**2.80%**	**4.15%**	
Virginia Power	**$ 476**	**$ 679**	**$ 850**	**$ 350**	**$**	**$ 7,070**	**$ 9,425**
Weighted-average Coupon	**5.24%**	**5.44%**	**4.17%**	**5.00%**		**4.59%**	
Dominion							
Unsecured Senior Notes[1]	**$ 1,907**	**$ 1,354**	**$ 1,850**	**$ 2,000**	**$ 700**	**$ 13,230**	**$ 21,041**
Tax-Exempt Financings	**19**	**75**				**880**	**974**
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts						**10**	**10**
Enhanced Junior Subordinated Notes						**1,348**	**1,348**
Remarketable Subordinated Notes				**550**	**1,000**	**550**	**2,100**
Total	**$ 1,926**	**$ 1,429**	**$ 1,850**	**$ 2,550**	**$ 1,700**	**$ 16,018**	**$ 25,473**
Weighted-average Coupon	**2.31%**	**3.28%**	**4.16%**	**3.09%**	**2.04%**	**4.54%**	

(1) *In February 2016, Dominion purchased and cancelled $100 million of variable rate short-term notes that would have otherwise matured in May 2016 using the proceeds from the February 2016 issuance of senior notes that mature in 2018. As a result, at December 31, 2015, $100 million of the notes were included in long-term debt in the Consolidated Balance Sheets.*

The Companies short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2015, there were no events of default under these covenants.

In January 2016, Virginia Power issued $750 million of 3.15% senior notes that mature in 2026.

In February 2016, Dominion issued $500 million of 2.125% senior notes in a private placement. The notes mature in 2018.

Senior Note Redemptions

As part of Dominion s Liability Management Exercise, in December 2014, Dominion redeemed five outstanding series of senior notes with an aggregate outstanding principal of $1.9 billion. The aggregate redemption price paid in December 2014 was $2.2 billion and represents the principal amount outstanding, accrued and unpaid interest and the applicable make-whole premium of $263 million. Total charges for the Liability Management Exercise of $284 million, including the make-whole premium, were recognized and recorded in interest expense in Dominion s Consolidated Statements of Income. Proceeds from Dominion s issuance of senior notes in November 2014 were used to offset the payment of the redemption price. Also see Convertible Securities called for redemption below.

Convertible Securities

As part of Dominion s Liability Management Exercise, in November 2014, Dominion provided notice to redeem all $22 million of outstanding contingent convertible senior notes. The senior notes were eligible for conversion during 2014. However, in lieu of redemption, holders elected to convert the remaining $22 million of notes in December 2014 into $26 million of common stock. Proceeds from Dominion s issuance of senior notes in November 2014 were used to offset the portion of the conversions paid in cash. At December 31, 2014, all of the senior notes have been converted and none remain outstanding.

Junior Subordinated Notes Payable to Affiliated Trusts

In previous years, Dominion established several subsidiary capital trusts, each as a finance subsidiary of Dominion, which holds 100% of the voting interests. The trusts sold capital 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 capital securities and common securities that represent the remaining 3% beneficial ownership interest in the assets held by the capital trusts, Dominion issued various junior subordinated notes. The junior subordinated notes constitute 100% of each capital trust s assets. Each trust must redeem its capital securities when their respective junior subordinated notes are repaid at maturity or if redeemed prior to maturity.

In January 2013, Dominion repaid its $258 million 7.83% unsecured junior subordinated debentures and redeemed all 250 thousand units of the $250 million 7.83% Dominion Resources Capital Trust I capital securities due December 1, 2027. The securities were redeemed at a price of $1,019.58 per capital security plus accrued and unpaid distributions.

Interest charges related to Dominion s junior subordinated notes payable to affiliated trusts were $1 million for the years ended December 31, 2015, 2014 and 2013.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, Dominion issued $300 million of June 2006 hybrids and $500 million of September 2006 hybrids, respectively. The June 2006 hybrids bear interest at 7.5% per year until June 30, 2016. Thereafter, they will bear interest at the three-month LIBOR plus 2.825%, reset quarterly. The September 2006 hybrids bear interest at the three-month LIBOR plus 2.3%, reset quarterly.

In June 2009, Dominion issued $685 million of 8.375% June 2009 hybrids. The June 2009 hybrids were listed on the NYSE under the symbol DRU.

In October 2014, Dominion issued $685 million of October 2014 hybrids that will bear interest at 5.75% per year until October 1, 2024. Thereafter, they will bear interest at the three-month LIBOR plus 3.057%, reset quarterly.

Dominion 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, Dominion may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments during the deferral period. Also, during the deferral period, Dominion 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.

Dominion executed RCCs in connection with its issuance of the June 2006 hybrids, the September 2006 hybrids, and the June 2009 hybrids. Under the terms of the RCCs, Dominion covenants to and for the benefit of designated covered debtholders, as may be designated from time to time, that Dominion shall not redeem, repurchase, or defease all or any part of the hybrids, and shall not cause its majority owned subsidiaries to purchase all or any part of the hybrids, on or before their applicable RCC termination date, unless, subject to certain limitations, during the 180 days prior to such activity, Dominion has received a specified amount of proceeds as set forth in the RCCs from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than the applicable characteristics of the hybrids at that time, as more fully described in the RCCs. In September 2011, Dominion amended the RCCs of the June 2006 hybrids and September 2006 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock issuances from 180 days to 365 days. In July 2014, Dominion amended the RCC of the June 2009 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock or other equity-like issuances from 180 days to 365 days. The proceeds Dominion receives from the replacement offering, adjusted by a predetermined factor, must equal or exceed the redemption or repurchase price.

As part of Dominion s Liability Management Exercise, in October 2014, Dominion redeemed all $685 million of the June 2009 hybrids plus accrued interest with the net proceeds from the issuance of the October 2014 hybrids. In 2015, Dominion purchased and canceled $14 million and $3 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In the first quarter of 2016, Dominion purchased and cancelled $37 million and $2 million of the June 2006 hybrids and the September 2006 hybrids, respectively. The redemption and all purchases were conducted in compliance with the RCCs.

Remarketable Subordinated Notes

In June 2013, Dominion issued $550 million of 2013 Series A 6.125% Equity Units and $550 million of 2013 Series B 6% Equity Units, initially in the form of Corporate Units. In July 2014, Dominion issued $1.0 billion of 2014 Series A 6.375% Equity Units, initially in the form of Corporate Units. The Corporate Units are listed on the NYSE under the symbols DCUA, DCUB and DCUC, respectively.

Each Corporate Unit consists of a stock purchase contract and 1/20 interest in a RSN issued by Dominion. The stock purchase contracts obligate the holders to purchase shares of Dominion common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price to be paid under the stock purchase contracts is $50 per Corporate Unit and the number of shares to be purchased will be determined under a formula based upon the average closing price of Dominion common stock near the settlement date. The RSNs are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

Dominion makes quarterly interest payments on the RSNs and quarterly contract adjustment payments on the stock purchase contracts, at the rates described below. Dominion may defer payments on the stock purchase contracts and the RSNs for one or more consecutive periods but generally not beyond the purchase contract settlement date. If payments are deferred, Dominion may not make any cash distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, Dominion 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 RSNs.

Dominion has recorded the present value of the stock purchase contract payments as a liability offset by a charge to equity. Interest payments on the RSNs are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as imputed interest expense. In calculating diluted EPS, Dominion applies the treasury stock method to the Equity Units.

Pursuant to the terms of the 2013 Equity Units and 2014 Equity Units, Dominion expects to remarket the 2013 Series A, 2013 Series B and 2014 Series A RSNs during the first and second quarters of 2016, and the second quarter of 2017, respectively. Following a successful remarketing, the interest rate on the RSNs will be reset, interest will be payable on a semi-annual basis and Dominion will cease to have the ability to redeem the RSNs at its option or defer interest payments. Proceeds of each remarketing will belong to the investors in the related equity units and will be held and applied on their behalf at the settlement date of the related stock purchase contracts to pay the purchase price to Dominion for issuance of its common stock.

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Combined Notes to Consolidated Financial Statements, Continued

Under the terms of the stock purchase contracts, assuming no anti-dilution or other adjustments, Dominion will issue between 8.5 million and 10.0 million shares of its common stock in both April 2016 and July 2016 and between 11.5 million and 14.4 million shares in July 2017. A total of 40.3 million shares of Dominion s common stock has been reserved for issuance in connection with the stock purchase contracts.

Selected information about Dominion s Equity Units is presented below:

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt	RSN Annual Interest Rate	Stock Purchase Contract Annual Rate	Stock Purchase Contract Liability(1)	Stock Purchase Settlement Date	RSN Maturity Date
(millions, except interest rates)								
6/7/2013	11	$ 533.5	$ 550.0	1.070%	5.055%	$ 76.7	4/1/2016	4/1/2021
6/7/2013	11	$ 553.5	$ 550.0	1.180%	4.820%	$ 79.3	7/1/2016	7/1/2019
7/1/2014	20	$ 982.0	$ 1,000.0	1.500%	4.875%	$ 142.8	7/1/2017	7/1/2020

(1) Payments of $101 million and $66 million were made in 2015 and 2014, respectively. The stock purchase contract liability was $115 million and $216 million at December 31, 2015 and 2014, respectively.

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NOTE 18. PREFERRED STOCK

Dominion is authorized to issue up to 20 million shares of preferred stock; however, none were issued and outstanding at December 31, 2015 or 2014.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. During 2014, Virginia Power redeemed 2.59 million shares, which represented all outstanding series of its preferred stock, some of which were redeemed as a part of Dominion s Liability Management Exercise in September 2014. Upon redemption, each series was no longer outstanding for any purpose and dividends ceased to accumulate. Virginia Power had no preferred stock issued and outstanding at December 31, 2015 or 2014.

NOTE 19. EQUITY

Issuance of Common Stock

DOMINION

Dominion maintains Dominion Direct® and a number of employee savings plans through which contributions may be invested in Dominion s common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion began purchasing its common stock on the open market for these plans. In April 2014, Dominion began issuing new common shares for these direct stock purchase plans.

During 2015, Dominion received cash proceeds, net of fees and commissions, of $783 million from the issuance of approximately 11 million shares of common stock through various programs resulting in approximately 596 million of shares of common stock outstanding at December 31, 2015. These proceeds include cash of $284 million received from the issuance of 4.1 million of such shares through Dominion Direct® and employee savings plans.

In December 2014, Dominion filed an SEC shelf registration for the sale of debt and equity securities including the ability to sell common stock through an at-the-market program. Also in December 2014, Dominion entered into four separate sales agency agreements to effect sales under the program and pursuant to which it may offer from time to time up to $500 million aggregate amount of its common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the NYSE at market prices or in such other transactions as are agreed upon by Dominion and the sales agents and in conformance with applicable securities laws. During the first and

second quarters of 2015, Dominion provided sales instructions to the sales agents and issued 4.0 million shares through at-the-market issuances and received cash proceeds of $297 million, net of fees and commissions paid of $3 million. Following these issuances, Dominion has the ability to issue up to approximately $200 million of stock under the 2014 sales agency agreements. However, Dominion completed its 2015 planned market issuances of equity in May 2015 with the issuance of 2.8 million shares and receipt of proceeds of $202 million through a registered underwritten public offering.

VIRGINIA POWER

In 2015, 2014 and 2013, Virginia Power did not issue any shares of its common stock to Dominion.

Dominion Gas

On September 30, 2013, Dominion contributed its wholly-owned subsidiaries DTI, East Ohio and Dominion Iroquois to Dominion Gas in exchange for 100% of its limited liability company membership interests.

Shares Reserved for Issuance

At December 31, 2015, Dominion had approximately 50 million shares reserved and available for issuance for Dominion Direct®, employee stock awards, employee savings plans, director stock compensation plans and issuance in connection with stock purchase contracts. See Note 17 for more information.

Repurchase of Common Stock

Dominion did not repurchase any shares in 2015 or 2014 and does not plan to repurchase shares during 2016, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which do not count against its stock repurchase authorization.

Purchase of Dominion Midstream Units

In September 2015, Dominion initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Midstream. The common units may be acquired by Dominion over the 12 month period following commencement of the program at the discretion of management. Through December 31, 2015, Dominion purchased approximately 887,000 common units for $25 million. In the first quarter of 2016, Dominion purchased approximately 377,000 additional common units for approximately $10 million. At February 23, 2016, Dominion still has the ability to purchase up to $15 million of common units under the program.

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Combined Notes to Consolidated Financial Statements, Continued

Accumulated Other Comprehensive Income (Loss)

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

At December 31, (millions)	**2015**	2014
Dominion		
Net deferred losses on derivatives-hedging activities, net of tax of $110 and $116	**$ (176)**	$ (178)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(281) and $(333)	**504**	548
Net unrecognized pension and other postretirement benefit costs, net of tax of $525 and $530	**(797)**	(782)
Other comprehensive loss from equity method investees, net of tax of $4 and $3	**(5)**	(4)
Total AOCI	**$ (474)**	$ (416)
Virginia Power		
Net deferred losses on derivatives-hedging activities, net of tax of $4 and $4	**$ (7)**	$ (7)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(30) and $(35)	**47**	57
Total AOCI	**$ 40**	$ 50
Dominion Gas		
Net deferred losses on derivatives-hedging activities, net of tax of $10 and $11	**$ (17)**	$ (20)
Net unrecognized pension costs, net of tax of $56 and $46	**(82)**	(66)
Total AOCI	**$ (99)**	$ (86)

DOMINION

The following table presents Dominion s changes in AOCI by component, net of tax:

(millions)	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Unrecognized pension and other postretirement benefit costs	Other comprehensive loss from equity method investees	Total
Year Ended December 31, 2015					
Beginning balance	**$ (178)**	**$ 548**	**$ (782)**	**$ (4)**	**$ (416)**
Other comprehensive income before reclassifications: gains (losses)	**110**	**6**	**(66)**	**(1)**	**49**
Amounts reclassified from AOCI: (gains) losses[1]	**(108)**	**(50)**	**51**		**(107)**
Net current period other comprehensive income (loss)	**2**	**(44)**	**(15)**	**(1)**	**(58)**
Ending balance	**$ (176)**	**$ 504**	**$ (797)**	**$ (5)**	**$ (474)**
Year Ended December 31, 2014					
Beginning balance	$ (288)	$ 474	$ (510)	$	$ (324)
Other comprehensive income before reclassifications: gains (losses)	17	128	(305)	(4)	(164)
Amounts reclassified from AOCI: (gains) losses[1]	93	(54)	33		72
Net current period other comprehensive income (loss)	110	74	(272)	(4)	(92)
Ending balance	$ (178)	$ 548	$ (782)	$ (4)	$ (416)

(1) See table below for details about these reclassifications.

The following table presents Dominion s reclassifications out of AOCI by component:

Details about AOCI components (millions)		Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
Year Ended December 31, 2015			
Deferred (gains) and losses on derivatives-hedging activities:			
Commodity contracts	**$**	**(203)**	Operating revenue
		15	Purchased gas
		1	Electric fuel and other energy-related purchases
Interest rate contracts		**11**	Interest and related charges
Total		**(176)**	
Tax		**68**	Income tax expense
Total, net of tax	**$**	**(108)**	
Unrealized (gains) and losses on investment securities:			
Realized (gain) loss on sale of securities	**$**	**(110)**	Other income
Impairment		**31**	Other income
Total		**(79)**	
Tax		**29**	Income tax expense
Total, net of tax	**$**	**(50)**	
Unrecognized pension and other postretirement benefit costs:			
Prior-service costs (credits)	**$**	**(12)**	Other operations and maintenance
Actuarial losses		**98**	Other operations and maintenance
Total		**86**	
Tax		**(35)**	Income tax expense
Total, net of tax	**$**	**51**	
Year Ended December 31, 2014			
Deferred (gains) and losses on derivatives-hedging activities:			
Commodity contracts	$	130	Operating revenue
		13	Purchased gas
		(7)	Electric fuel and other energy-related purchases
Interest rate contracts		16	Interest and related charges
Total		152	
Tax		(59)	Income tax expense
Total, net of tax	$	93	
Unrealized (gains) and losses on investment securities:			
Realized (gain) loss on sale of securities	$	(100)	Other income
Impairment		13	Other income
Total		(87)	
Tax		33	Income tax expense
Total, net of tax	$	(54)	
Unrecognized pension and other postretirement benefit costs:			
Prior-service costs (credits)	$	(12)	Other operations and maintenance
Actuarial losses		69	Other operations and maintenance
Total		57	
Tax		(24)	Income tax expense
Total, net of tax	$	33	

Virginia Power

The following table presents Virginia Power s changes in AOCI by component, net of tax:

(millions)	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Total
Year Ended December 31, 2015			
Beginning balance	**$ (7)**	**$ 57**	**$ 50**
Other comprehensive income before reclassifications: losses	**(1)**	**(4)**	**(5)**
Amounts reclassified from AOCI: (gains) losses[1]	**1**	**(6)**	**(5)**
Net current period other comprehensive income (loss)		**(10)**	**(10)**
Ending balance	**$ (7)**	**$ 47**	**$ 40**
Year Ended December 31, 2014			
Beginning balance	$	$ 48	$ 48
Other comprehensive income before reclassifications: gains (losses)	(4)	15	11
Amounts reclassified from AOCI: gains[1]	(3)	(6)	(9)
Net current period other comprehensive income (loss)	(7)	9	2
Ending balance	$ (7)	$ 57	$ 50

(1) See table below for details about these reclassifications.

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The following table presents Virginia Power s reclassifications out of AOCI by component:

Details about AOCI components (millions)		Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
Year Ended December 31, 2015			
(Gains) losses on cash flow hedges:			
Commodity contracts	**$**	**1**	Electric fuel and other energy-related purchases
Total		**1**	
Tax			Income tax expense
Total, net of tax	**$**	**1**	
Unrealized (gains) and losses on investment securities:			
Realized (gain) loss on sale of securities	**$**	**(14)**	Other income
Impairment		**4**	Other income
Total		**(10)**	
Tax		**4**	Income tax expense
Total, net of tax	**$**	**(6)**	
Year Ended December 31, 2014			
(Gains) losses on cash flow hedges:			
Commodity contracts	$	(5)	Electric fuel and other energy-related purchases
Total		(5)	
Tax		2	Income tax expense
Total, net of tax	$	(3)	
Unrealized (gains) and losses on investment securities:			
Realized (gain) loss on sale of securities	$	(10)	Other income
Total		(10)	
Tax		4	Income tax expense
Total, net of tax	$	(6)	

Dominion Gas

The following table presents Dominion Gas changes in AOCI by component, net of tax:

(millions)		Deferred gains and losses on derivatives-hedging activities		Unrecognized pension costs	Total
Year Ended December 31, 2015					
Beginning balance	**$**	**(20)**	**$**	**(66)**	**$ (86)**
Other comprehensive income before reclassifications: gains (losses)		**6**		**(20)**	**(14)**

Amounts reclassified from AOCI: (gains) losses[1]		**(3)**		**4**	**1**
Net current period other comprehensive income (loss)		**3**		**(16)**	**(13)**
Ending balance	**$**	**(17)**	**$**	**(82)**	**$ (99)**
Year Ended December 31, 2014					
Beginning balance	$	3	$	(61)	$ (58)
Other comprehensive income before reclassifications: losses		(31)		(10)	(41)
Amounts reclassified from AOCI: losses[1]		8		5	13
Net current period other comprehensive loss		(23)		(5)	(28)
Ending balance	$	(20)	$	(66)	$ (86)

(1) See table below for details about these reclassifications.

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The following table presents Dominion Gas reclassifications out of AOCI by component:

Details about AOCI components (millions)		Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
Year Ended December 31, 2015			
Deferred (gains) and losses on derivatives-hedging activities:			
Commodity contracts	**$**	**(6)**	Operating revenue
Total		**(6)**	
Tax		**3**	Income tax expense
Total, net of tax	**$**	**(3)**	
Unrecognized pension costs:			
Actuarial losses	**$**	**7**	Other operations and maintenance
Total		**7**	
Tax		**(3)**	Income tax expense
Total, net of tax	**$**	**4**	
Year Ended December 31, 2014			
Deferred (gains) and losses on derivatives-hedging activities:			
Commodity contracts	$	(2)	Operating revenue
		14	Purchased gas
Interest rate contracts		1	Interest and related charges
Total		13	
Tax		(5)	Income tax expense
Total, net of tax	$	8	
Unrecognized pension costs:			
Prior service costs	$	1	Other operations and maintenance
Actuarial losses		7	Other operations and maintenance
Total		8	
Tax		(3)	Income tax expense
Total, net of tax	$	5	

Stock-Based Awards

The 2005 and 2014 Incentive Compensation Plans permit stock-based awards that include restricted stock, performance grants, goal-based stock, stock options, and stock appreciation rights. The Non-Employee Directors Compensation Plan permits grants of restricted stock and stock options. Under provisions of these 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 are set at the discretion of the CGN Committee of the Board of Directors or the Board of Directors itself, as provided under each plan. At December 31, 2015, approximately 25 million shares were available for future grants under these plans.

Dominion measures and recognizes compensation expense relating to share-based payment transactions over the vesting period based on the fair value of the equity or liability instruments issued. Dominion s results for the years ended December 31, 2015, 2014 and 2013 include $39 million, $39 million, and $31 million, respectively, of compensation costs and $14 million, $14 million, and $11 million, respectively of income tax benefits related to Dominion s stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in Dominion s Consolidated Statements of Income. Excess Tax Benefits are classified as a financing cash flow. Dominion realized $3 million of excess tax benefits from the vesting of restricted stock awards and exercise of stock options during the year ended December 31, 2015, and less than $1 million during the years ended December 31, 2014 and 2013.

Restricted Stock

Restricted stock grants are made to officers under Dominion s LTIP and may also be granted to certain key non-officer employees from time to time. The fair value of Dominion s restricted stock awards is equal to the closing price of Dominion s stock on the date of grant. New shares are issued for restricted stock awards on the date of grant and generally vest over a three-year service period. The following table provides a summary of restricted stock activity for the years ended December 31, 2015, 2014 and 2013:

	Shares (thousands)	Weighted - average Grant Date Fair Value
Nonvested at December 31, 2012	1,085	$ 44.46
Granted	312	54.70
Vested	(356)	39.00
Cancelled and forfeited	(34)	51.11
Nonvested at December 31, 2013	1,007	$ 49.35
Granted	354	67.98
Vested	(278)	44.50
Cancelled and forfeited	(18)	53.61
Nonvested at December 31, 2014	1,065	$ 56.74
Granted	**302**	**73.26**
Vested	**(510)**	**50.71**
Cancelled and forfeited	**(2)**	**62.62**
Nonvested at December 31, 2015	**855**	**$ 66.16**

As of December 31, 2015, unrecognized compensation cost related to nonvested restricted stock awards totaled $27 million and is expected to be recognized over a weighted-average period of 2.0 years. The fair value of restricted stock awards that vested was $37 million, $19 million, and $20 million in 2015, 2014 and 2013, 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 market value of Dominion stock and the applicable federal, state and local tax withholding rates.

Goal-Based Stock

Goal-based stock awards are granted under Dominion s LTIP to officers who have not achieved a certain targeted level of share

Combined Notes to Consolidated Financial Statements, Continued

ownership, in lieu of cash-based performance grants. Goal-based stock awards may also be made to certain key non-officer employees from time to time. Current outstanding goal-based shares include awards granted to officers in February 2014 and February 2015.

The issuance of awards is based on the achievement of two performance metrics during a two-year period: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. 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 closing price of Dominion s stock on the date of grant. Goal-based stock awards granted to key non-officer employees convert to restricted stock at the end of the two-year performance period and generally vest three years from the original grant date. Awards to officers vest at the end of the two-year performance period. All goal-based stock awards are settled by issuing new shares.

The following table provides a summary of goal-based stock activity for the years ended December 31, 2015, 2014 and 2013:

	Targeted Number of Shares (thousands)	Weighted - average Grant Date Fair Value
Nonvested at December 31, 2012	4	$ 45.60
Granted	4	54.17
Vested	(2)	43.54
Cancelled and forfeited	(1)	43.54
Nonvested at December 31, 2013	5	$ 53.85
Granted	13	68.83
Vested	(1)	52.48
Nonvested at December 31, 2014	17	$ 65.15
Granted	**14**	**72.72**
Vested	**(7)**	**56.22**
Nonvested at December 31, 2015	**24**	**$ 72.27**

At December 31, 2015, the targeted number of shares expected to be issued under the February 2014 and February 2015 awards was approximately 24 thousand. In January 2016, the CGN Committee determined the actual performance against metrics established for the February 2014 awards with a performance period that ended December 31, 2015. Based on that determination, the total number of shares to be issued under the February 2014 goal-based stock awards was approximately 10 thousand.

As of December 31, 2015, unrecognized compensation cost related to nonvested goal-based stock awards was not material.

Cash-Based Performance Grants

Cash-based performance grants are made to Dominion s officers under Dominion s LTIP. The actual payout of cash-based performance grants will vary between zero and 200% of the targeted amount based on the level of performance metrics achieved.

In February 2012, a cash-based performance grant was made to officers. A portion of the grant, representing the initial payout of $8 million was paid in December 2013, based on the achievement of two performance metrics during 2012 and 2013: TSR relative to that of companies listed as members of the Philadelphia

Utility Index as of the end of the performance period and ROIC. The total amount of the award under the grant was $12 million and the remaining portion of the grant was paid in January 2014.

In February 2013, a cash-based performance grant was made to officers. A portion of the grant, representing the initial payout of $14 million was paid in December 2014, based on the achievement of two performance metrics during 2013 and 2014: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total amount of the award under the grant was $20 million and the remaining portion of the grant was paid in February 2015.

In February 2014, a cash-based performance grant was made to officers. Payout of the performance grant is expected to occur by March 15, 2016 based on the achievement of two performance metrics during 2014 and 2015: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total expected award under the grant is $10 million and the grant is expected to be paid by March 15, 2016. At December 31, 2015, a liability of $10 million had been accrued for this award.

In February 2015, a cash-based performance grant was made to officers. Payout of the performance grant is expected to occur by March 15, 2017 based on the achievement of two performance metrics during 2015 and 2016: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. At December 31, 2015, the targeted amount of the grant was $14 million and a liability of $7 million had been accrued for this award.

NOTE 20. 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, 2015, the Virginia Commission had not restricted the payment of dividends by Virginia Power.

The Ohio Commission may prohibit any public service company, including East Ohio, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2015, the Ohio Commission had not restricted the payment of dividends by East Ohio.

Certain agreements associated with the Companies credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Companies ability to pay dividends or receive dividends from their subsidiaries at December 31, 2015.

See Note 17 for a description of potential restrictions on dividend payments by Dominion in connection with the deferral of interest payments on junior subordinated notes and equity units, initially in the form of corporate units.

NOTE 21. EMPLOYEE BENEFIT PLANS

Dominion and Dominion Gas Defined Benefit Plans

Dominion provides certain retirement benefits to eligible active employees, retirees and qualifying dependents. Dominion Gas participates in a number of the Dominion-sponsored retirement

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

Dominion maintains 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. Dominion s funding policy is to contribute annually an amount that is in accordance with the provisions of ERISA. The pension program also provides benefits to certain retired executives under a company-sponsored nonqualified employee benefit plan. The nonqualified plan is funded through contributions to a grantor trust. Dominion also provides retiree healthcare and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

Pension benefits for Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan, a defined benefit pension plan sponsored by Dominion that provides benefits to multiple Dominion subsidiaries. Pension benefits for Dominion Gas employees represented by collective bargaining units are covered by separate pension plans for East Ohio and, for DTI, a plan that provides benefits to employees of both DTI and Hope. Employee compensation is the basis for allocating pension costs and obligations between DTI and Hope and determining East Ohio s share of total pension costs.

Retiree healthcare and life insurance benefits for Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Retiree Health and Welfare Plan, a plan sponsored by Dominion that provides certain retiree healthcare and life insurance benefits to multiple Dominion subsidiaries. Retiree healthcare and life insurance benefits for Dominion Gas employees represented by collective bargaining units are covered by separate other postretirement benefit plans for East Ohio and, for DTI, a plan that provides benefits to both DTI and Hope. Employee headcount is the basis for allocating other postretirement benefit costs and obligations between DTI and Hope and determining East Ohio s share of total other postretirement benefit costs.

Pension and other postretirement benefit costs are affected by employee demographics (including age, compensation levels and years of service), the level of contributions made to the plans and earnings on plan assets. These costs may also be affected by changes in key assumptions, including expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates, mortality rates and the rate of compensation increases.

Dominion uses December 31 as the measurement date for all of its employee benefit plans, including those in which Dominion Gas participates. Dominion uses the market-related value of pension plan assets to determine the expected return on plan assets, a component of net periodic pension cost, for all pension plans, including those in which Dominion Gas participates. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period, which reduces year-to-year volatility. 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. Since the market-related value recognizes changes in

fair value over a four-year period, the future market-related value of pension plan assets will be impacted as previously unrecognized changes in fair value are recognized.

Dominion s pension and other postretirement benefit plans hold investments in trusts to fund employee benefit payments. Dominion s pension and other postretirement plan assets experienced aggregate actual losses of $72 million in 2015 and aggregate actual returns of $706 million in 2014, versus expected returns of $648 million and $610 million, respectively. Dominion Gas pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual losses of $13 million in 2015 and aggregate actual returns of $157 million in 2014, versus expected returns of $150 million and $138 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

The Medicare Act introduced a federal subsidy to sponsors of retiree healthcare benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D. Dominion determined that the prescription drug benefit offered under its other postretirement benefit plans is at least actuarially equivalent to Medicare Part D. Dominion and Dominion Gas received a federal subsidy of $4 million and $1 million, respectively, for 2014. Effective January 1, 2013, Dominion changed its method of receiving the subsidy under Medicare Part D for retiree prescription drug coverage from the Retiree Drug Subsidy to the EGWP. This change reduced other postretirement benefit costs by approximately $20 million annually beginning in 2012. As a result of the adoption of the EGWP, Dominion begins to receive an increased level of Medicare Part D subsidies in the form of reduced costs rather than a direct reimbursement.

In October 2014, the Society of Actuaries published new mortality tables and mortality improvement scales. Such tables and scales are used to develop mortality assumptions for use in determining pension and other postretirement benefit liabilities and expense. Following evaluation of the new tables, Dominion changed its assumption for mortality rates to reflect a generational improvement scale. As a result of this change in assumption, at December 31, 2014 Dominion and Dominion Gas (for employees represented by collective bargaining units) increased their pension benefit obligations by $131 million and $10 million, respectively, and increased their accumulated postretirement benefit obligations by $32 million and $7 million, respectively. This change increased net periodic benefit cost for Dominion and Dominion Gas (for employees represented by collective bargaining units) by $25 million and $3 million, respectively, for 2015.

Dominion remeasured all of its pension and other postretirement benefit plans in the second quarter of 2013. The remeasurement resulted in a reduction in the pension benefit obligation of $354 million and a reduction in the accumulated postretirement benefit obligation of $78 million. For Dominion Gas employees represented by collective bargaining units, the remeasurement resulted in a reduction in the pension benefit obligation of $28 million and a reduction in the accumulated postretirement benefit obligation of $9 million. The impact of the remeasurement on net periodic benefit (credit) cost was recognized prospectively from the remeasurement date and reduced net periodic benefit cost for 2013 by $36 million, excluding the impacts of curtailments, and for Dominion Gas employees represented by collective bargaining units by $2 million. The discount rate used for the remeasurement was 4.80% for the pension plans and 4.70% for the other postretirement benefit plans. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2012.

In the fourth quarter of 2013, Dominion remeasured its other postretirement benefit plans as a result of a plan amendment that changed medical coverage for certain Medicare-eligible retirees effective April 2014. The remeasurement resulted in a reduction in the accumulated postretirement benefit obligation of $220 million. The impact of the remeasurement on net periodic benefit (credit) cost was recognized prospectively from the remeasurement date and reduced net periodic benefit cost for 2013 by $8 million. The amendment is expected to reduce net periodic benefit cost by $40 million to $60 million for each of the next five years. The discount rate used for the remeasurement was 4.80%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2012.

In the third quarter of 2014, East Ohio remeasured its other postretirement benefit plan as a result of an amendment that changed medical coverage upon the attainment of age 65 for certain future retirees effective January 1, 2016. For employees represented by collective bargaining units, the remeasurement resulted in an increase in the accumulated postretirement benefit obligation of $22 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and reduced net periodic benefit credit for 2014, for employees represented by collective bargaining units, by less than $1 million. The discount rate used for the remeasurement was 4.20% and the expected long-term rate of return used was 8.50%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2013.

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Funded Status

The following table summarizes the changes in pension plan and other postretirement benefit plan obligations and plan assets and includes a statement of the plans funded status for Dominion and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	**2015**	2014	**2015**	2014
(millions, except percentages)				
DOMINION				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 6,667**	$ 5,625	**$ 1,571**	$ 1,360
Service cost	**126**	114	**40**	32
Interest cost	**287**	290	**67**	67
Benefits paid	**(246)**	(236)	**(79)**	(78)
Actuarial (gains) losses during the year	**(443)**	887	**(138)**	177
Plan amendments(1)			**(31)**	9
Settlements and curtailments(2)		(13)		
Medicare Part D reimbursement				4
Benefit obligation at end of year	**$ 6,391**	$ 6,667	**$ 1,430**	$ 1,571
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 6,480**	$ 6,113	**$ 1,402**	$ 1,315
Actual return (loss) on plan assets	**(71)**	601	**(1)**	105
Employer contributions	**3**	15	**12**	12
Benefits paid	**(246)**	(236)	**(31)**	(30)
Settlements(2)		(13)		
Fair value of plan assets at end of year	**$ 6,166**	$ 6,480	**$ 1,382**	$ 1,402
Funded status at end of year	**$ (225)**	$ (187)	**$ (48)**	$ (169)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 931**	$ 946	**$ 12**	$ 10
Other current liabilities	**(14)**	(13)	**(3)**	(3)
Noncurrent pension and other postretirement benefit liabilities	**(1,142)**	(1,120)	**(57)**	(176)
Net amount recognized	**$ (225)**	$ (187)	**$ (48)**	$ (169)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**4.96% 4.99%**	4.40%	**4.93% 4.94%**	4.40%
Weighted average rate of increase for compensation	**4.22%**	4.22%	**4.22%**	4.22%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	**8.50%**	8.50%
DOMINION GAS				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 638**	$ 563	**$ 320**	$ 269
Service cost	**15**	12	**7**	6
Interest cost	**27**	28	**14**	13
Benefits paid	**(29)**	(29)	**(18)**	(16)
Actuarial (gains) losses during the year	**(43)**	64	**(31)**	38
Plan amendments				9
Medicare Part D reimbursement				1
Benefit obligation at end of year	**$ 608**	$ 638	**$ 292**	$ 320
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 1,510**	$ 1,403	**$ 288**	$ 273
Actual return (loss) on plan assets	**(14)**	136	**1**	21
Employer contributions			**12**	10
Benefits paid	**(29)**	(29)	**(18)**	(16)
Fair value of plan assets at end of year	**$ 1,467**	$ 1,510	**$ 283**	$ 288
Funded status at end of year	**$ 859**	$ 872	**$ (9)**	$ (32)
Amounts recognized in the Consolidated Balance Sheets at December 31:				

Noncurrent pension and other postretirement benefit assets	**$**	**859**	$	872	**$**		$	
Noncurrent pension and other postretirement benefit liabilities[3]						**(9)**		(32)
Net amount recognized	**$**	**859**	$	872	**$**	**(9)**	$	(32)
Significant assumptions used to determine benefit obligations as of December 31:								
Discount rate		**4.99%**		4.40%		**4.93%**		4.40%
Weighted average rate of increase for compensation		**3.93%**		3.93%		**3.93%**		3.93%
Expected long-term rate of return on plan assets		**8.75%**		8.75%		**8.50%**		8.50%

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(1) 2015 amount relates primarily to a plan amendment that changed retiree medical benefits for certain nonunion employees after Medicare eligibility.
(2) Relates primarily to a settlement charge for certain executives.
(3) Reflected in other deferred credits and other liabilities in Dominion Gas Consolidated Balance Sheets.

The ABO for all of Dominion s defined benefit pension plans was $5.8 billion and $6.0 billion at December 31, 2015 and 2014, respectively. The ABO for the defined benefit pension plans covering Dominion Gas employees represented by collective bargaining units was $578 million and $604 million at December 31, 2015 and 2014, respectively.

Under its funding policies, Dominion evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, Dominion determines the amount of contributions for the current year, if any, at that time. During 2015, Dominion and Dominion Gas made no contributions to the qualified defined benefit pension plans and no contributions are currently expected in 2016. In July 2012, the MAP 21 Act was signed into law. This Act includes an increase in the interest rates used to determine plan sponsors pension contributions for required funding purposes. In 2014, the HATFA of 2014 was signed into law. Similar to the MAP 21 Act, the HATFA of 2014 adjusts the rules for calculating interest rates used in determining funding obligations. It is estimated that the new interest rates will reduce required pension contributions through 2019. Dominion believes that required pension contributions will rise subsequent to 2019, resulting in an estimated $200 million reduction in net cumulative required contributions over a 10-year period.

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 Dominion s subsidiaries, including Dominion Gas, fund other postretirement benefit costs through VEBAs. Dominion s remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. Dominion s contributions to VEBAs, all of which pertained to Dominion Gas employees, totaled $12 million for both 2015 and 2014, and Dominion expects to contribute approximately $12 million to the Dominion VEBAs in 2016, all of which pertains to Dominion Gas employees.

Dominion and Dominion Gas do not expect any pension or other postretirement plan assets to be returned during 2016.

The following table provides information on the benefit obligations and fair value of plan assets for plans with a benefit obligation in excess of plan assets for Dominion and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
As of December 31, (millions)	**2015**	2014	**2015**	2014
DOMINION				
Benefit obligation	**$ 5,728**	$ 5,970	**$ 359**	$ 1,564
Fair value of plan assets	**4,571**	4,838	**299**	1,385
DOMINION GAS				
Benefit obligation	**$**	$	**$ 292**	$ 320
Fair value of plan assets			**283**	288

The following table provides information on the ABO and fair value of plan assets for Dominion s pension plans with an ABO in excess of plan assets:

As of December 31,	2015	2014
(millions)		
Accumulated benefit obligation	**$ 5,198**	$ 5,370
Fair value of plan assets	**4,571**	4,838

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid for Dominion s and Dominion Gas (for employees represented by collective bargaining units) plans:

	Estimated Future Benefit Payments	
	Pension Benefits	Other Postretirement Benefits
(millions)		
DOMINION		
2016	**$ 288**	**$ 92**
2017	**303**	**96**
2018	**324**	**99**
2019	**337**	**100**
2020	**359**	**102**
2021-2025	**2,023**	**512**
DOMINION GAS		
2016	**$ 35**	**$ 18**
2017	**37**	**19**
2018	**39**	**21**
2019	**40**	**21**
2020	**41**	**21**
2021-2025	**208**	**107**

Plan Assets

Dominion s overall objective for investing its pension and other postretirement plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. As a participating employer in various pension plans sponsored by Dominion, Dominion Gas is subject to Dominion s investment policies for such plans. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocations for Dominion s pension funds are 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments. U.S. equity includes investments in large-cap,

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mid-cap and small-cap companies located in the United States. Non-U.S. equity includes investments in large-cap and small-cap companies located outside of the United States including both developed and emerging markets. Fixed income includes corporate debt instruments of companies from diversified industries and U.S. Treasuries. The U.S. equity, non-U.S. equity and fixed income investments are in individual securities as well as mutual funds. Real estate includes equity REITs and investments in partnerships. Other alternative investments include partnership investments in private equity, debt and hedge funds that follow several different strategies.

Dominion also utilizes common/collective trust funds as an investment vehicle for its defined benefit plans. A common/collective trust fund is a pooled fund operated by a bank or trust company for investment of the assets of various organizations and individuals in a well-diversified portfolio. Common/collective trust funds are funds of grouped assets that follow various investment strategies.

Strategic investment policies are established for Dominion s prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans strategic allocation are a function of Dominion s assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities.

For fair value measurement policies and procedures related to pension and other postretirement benefit plan assets, see Note 6.

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The fair values of Dominion s and Dominion Gas (for employees represented by collective bargaining units) pension plan assets by asset category are as follows:

At December 31,	2015				2014			
(millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
DOMINION								
Cash equivalents	**$ 16**	**$**	**$**	**$ 16**	$ 13	$ 25	$	$ 38
U.S. equity:								
Large Cap	**1,178**			**1,178**	1,313			1,313
Other	**475**			**475**	530			530
Non-U.S. equity:								
Large Cap	**286**			**286**	234			234
Other	**493**			**493**	403			403
Common/collective trust funds(1)		**330**		**330**		360		360
Fixed income:								
Corporate debt instruments	**40**	**672**		**712**	45	666		711
U.S. Treasury securities and agency debentures	**60**	**298**		**358**	74	342		416
State and municipal	**20**	**54**		**74**	10	60		70
Other securities	**9**	**61**		**70**	6	80		86
Real estate-REITs	**90**			**90**	40			40
Total recorded at fair value	**$ 2,667**	**$ 1,415**	**$**	**$ 4,082**	$ 2,668	$ 1,533	$	$ 4,201
Assets recorded at NAV(2):								
Common/collective trust funds(1)				**1,200**				1,235
Real estate-Partnerships				**153**				209
Other alternative investments:								
Private equity				**465**				518
Debt				**170**				144
Hedge funds				**86**				162
Total recorded at NAV				**$ 2,074**				$ 2,268
Total(3)				**$ 6,156**				$ 6,469
DOMINION GAS								
Cash equivalents	**$ 4**	**$**	**$**	**$ 4**	$ 3	$ 6	$	$ 9
U.S. equity:								
Large Cap	**280**			**280**	306			306
Other	**113**			**113**	124			124
Non-U.S. equity:								
Large Cap	**68**			**68**	54			54
Other	**117**			**117**	94			94
Common/collective trust funds(4)		**78**		**78**		84		84
Fixed income:								
Corporate debt instruments	**9**	**160**		**169**	11	155		166
U.S. Treasury securities and agency debentures	**14**	**71**		**85**	17	80		97
State and municipal	**5**	**13**		**18**	2	14		16
Other securities	**2**	**14**		**16**	1	19		20
Real estate-REITs	**22**			**22**	9			9
Total recorded at fair value	**$ 634**	**$ 336**	**$**	**$ 970**	$ 621	$ 358	$	$ 979
Assets recorded at NAV(2):								
Common/collective trust funds(4)				**286**				288
Real estate-Partnerships				**36**				48

Other alternative investments:		
Private equity	**111**	121
Debt	**40**	34
Hedge funds	**21**	38
Total recorded at NAV	**$ 494**	$ 529
Total[(5)]	**$ 1,464**	$ 1,508

(1) Common/collective trust funds include $330 million and $360 million of John Hancock insurance contracts held at December 31, 2015 and 2014, respectively. See below for a description of the individual investments included within this line item, and the nature and risk of each respective fund.

(2) These investments that are measured at fair value using the NAV per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Consolidated Balance Sheets.

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(3) Includes net assets related to pending sales of securities of $112 million, net accrued income of $16 million, and excludes net assets related to pending purchases of securities of $118 million at December 31, 2015. Includes net assets related to pending sales of securities of $31 million, net accrued income of $18 million, and excludes net assets related to pending purchases of securities of $38 million at December 31, 2014.

(4) Common/collective trust funds include $78 million and $84 million of John Hancock insurance contracts held at December 31, 2015 and 2014, respectively. See below for a description of the individual investments included within this line item, and the nature and risk of each respective fund.

(5) Includes net assets related to pending sales of securities of $27 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $28 million at December 31, 2015. Includes net assets related to pending sales of securities of $7 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $9 million at December 31, 2014.

The fair values of Dominion s and Dominion Gas (for employees represented by collective bargaining units) other postretirement plan assets by asset category are as follows:

At December 31,	**2015**				2014			
(millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
DOMINION								
Cash equivalents	**$ 1**	**$ 1**	**$**	**$ 2**	$ 1	$ 7	$	$ 8
U.S. equity:								
Large Cap	**468**			**468**	514			514
Other	**26**			**26**	28			28
Non-U.S. equity:								
Large Cap	**107**			**107**	102			102
Other	**27**			**27**	21			21
Common/collective trust funds(1)		**18**		**18**		19		19
Fixed income:								
Corporate debt instruments	**2**	**37**		**39**	3	35		38
U.S. Treasury securities and agency debentures	**3**	**17**		**20**	4	18		22
State and municipal	**1**	**3**		**4**	1	3		4
Other securities	**1**	**3**		**4**		4		4
Real estate-REITs	**37**			**37**	2			2
Total recorded at fair value	**$ 673**	**$ 79**	**$**	**$ 752**	$ 676	$ 86	$	$ 762
Assets recorded at NAV(2):								
Common/collective trust funds(1)				**543**				536
Real estate-Partnerships				**14**				19
Other alternative investments:								
Private equity				**54**				58
Debt				**14**				18
Hedge funds				**5**				9
Total recorded at NAV				**$ 630**				$ 640
Total				**$ 1,382**				$ 1,402
DOMINION GAS								
Cash equivalents	**$**	**$**	**$**	**$**	$	$ 2	$	$ 2
U.S. equity-Large Cap	**102**			**102**	113			113
Non-U.S. equity-Large Cap	**24**			**24**	26			26
Real estate-REITs	**11**			**11**				
Total recorded at fair value	**$ 137**	**$**	**$**	**$ 137**	$ 139	$ 2	$	$ 141
Assets recorded at NAV(2):								
Common/collective trust funds(3)				**132**				129
Real estate-Partnerships				**2**				2
Other alternative investments:								
Private equity				**11**				12
Debt				**1**				4
Total recorded at NAV				**$ 146**				$ 147
Total				**$ 283**				$ 288

(1) Common/collective trust funds include $18 million and $19 million of John Hancock insurance contracts held at December 31, 2015 and 2014, respectively. See below for a description of the individual investments included within this line item, and the nature and risk of each respective fund.

(2) These investments that are measured at fair value using the NAV per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Consolidated Balance Sheets.

(3) See below for a description of the individual investments included within this line item, and the nature and risk of each respective fund.

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Combined Notes to Consolidated Financial Statements, Continued

Investments in Common/Collective Trust Funds in Dominion s pension and other postretirement plans, including those in which Dominion Gas participates, are stated at fair value as determined by the issuer of the Common/Collective Trust Funds based on the fair value of the underlying investments. The Common/Collective Trusts do not have any unfunded commitments, and do not have any applicable liquidation periods or defined terms/periods to be held. The majority of the Common/Collective Trust Funds have limited withdrawal or redemption rights during the term of the investment. Strategies of the Common/Collective Trust Funds are as follows:

Dominion and Dominion Gas

Wells Fargo Closed End Bond Trust-The Fund invests in stocks, bonds or a combination of both. Shares of the Fund are traded on a stock exchange and are subject to market risk like stocks, bonds and mutual funds. The Fund may invest in a less liquid portfolio of stocks and bonds because the fund does not need to sell securities to meet shareholder redemptions as mutual funds in order to keep a percentage of its portfolio in cash to pay back investors who withdraw shares.

JPMorgan Core Bond Trust-The Fund seeks to maximize total return by investing primarily in a diversified portfolio of intermediate- and long-term debt securities. The Fund invests primarily in investment-grade bonds; it generally maintains an average weighted maturity between four and 12 years. It may shorten its average weighted maturity if deemed appropriate for temporary defensive purposes.

SSgA Russell 2000 Value Index Common Trust-The Fund measures the performance of the small-cap value segment of the U.S. equity universe. The Russell 2000 Value Index is constructed to provide a comprehensive and unbiased barometer for the small-cap value segment. The Index is completely reconstituted annually to ensure larger stocks do not distort the performance and characteristics of the true small-cap opportunity set and that the represented companies continue to reflect value characteristics.

NT Common Short-Term Investment Fund-The Fund seeks to maximize current income on cash reserves to the extent consistent with principal preservation and maintenance of liquidity from a portfolio of approved money market instruments with short maturities. Liquidity is emphasized to provide for redemption of units at par on any business day. Principal preservation is a primary objective. Within quality, maturity, and sector diversification guidelines, investments are made in those securities with the most attractive yields.

Dominion

SSgA Daily MSCI Emerging Markets Index Non-Lending Fund-The Fund seeks an investment return that approximates as closely as practicable, before expenses, the performance of the MSCI Emerging Markets Index over the long term. The Fund may invest directly or indirectly in securities and other instruments, including in other pooled investment vehicles sponsored or managed by, or otherwise affiliated with the Trustee (State Street Bank and Trust Company).

SSgA Daily MSCI ACWI Ex-USA Index Non-Lending Fund-The Fund seeks an investment return that approximates as closely as practicable, before expenses, the performance of the MSCI ACWI Ex-USA Index over the long term. The Fund may invest directly or indirectly in securities and other instruments, including in other pooled investment vehicles sponsored or managed by, or otherwise affiliated with the Trustee (State Street Bank and Trust Company).

SSgA S&P 400 MidCap Index The Fund seeks an investment return that approximates as closely as practicable, before expenses, the performance of its benchmark index (the Index) over the long term. The S&P MidCap 400 is comprised of approximately 400 U.S. mid-cap securities and accounts for approximately 7% coverage of the U.S. stock market capitalization. SSgA will typically attempt to invest in the equity securities comprising the Index, in approximately the same proportions as they are represented in the Index.

SSgA S&P 500 Flagship Non-Lending Fund The Fund seeks an investment return that approximates as closely as practicable, before expenses, the performance of the S&P 500 Index over the long term. The S&P 500 is comprised of approximately 500 large-cap U.S. equities and captures approximately 80% coverage of available market capitalization. SSgA will typically attempt to invest in the equity securities comprising the S&P 500 Index, in approximately the same proportions as they are represented in the Index.

CF Goldman Sachs GSTCO Long Duration Fund-The Fund seeks to generate total return and prudent investment management through investments in fixed income securities. The Fund is actively managed and benchmarked versus the Barclays U.S. Long Government

/Credit Index. At least 75% of the Fund s total assets will be rated investment grade or better by a NRSRO at the time of purchase. The Fund may invest up to 25% of its total assets at the time of purchase in non-investment grade securities. The Fund may invest in non-dollar denominated securities that are fully hedged, unhedged or partially hedged.

JPMorgan Chase Bank U.S. Active Core Plus Equity Fund-The Fund seeks to outperform the S&P 500 Index (the Benchmark), gross of fees, over a market cycle. The Fund invests primarily in a portfolio of long and short positions in equity securities of large and mid capitalization U.S. companies with characteristics similar to those of the Benchmark.

NT Collective Russell 2000 Growth Index The Fund seeks an investment return that approximates the overall performance of the common stocks included in the Russell 2000 Growth Index. The Fund primarily invests in common stocks of one or more companies that are deemed to be representative of the industry diversification of the entire Russell 2000 Growth Index.

NT Collective Short-Term Investment Fund The Fund is composed of high-grade money market instruments with short-term maturities. The Fund s objective is to provide an investment vehicle for cash reserves while offering a competitive rate of return. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

Investments in Group Insurance Annuity Contracts with John Hancock were entered into after 1992 and are stated at fair value based on the fair value of the underlying securities as provided by the managers and include investments in U.S. government securities, corporate debt instruments, and state and municipal debt securities.

Net Periodic Benefit (Credit) Cost

Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Income. The components of the provision for net periodic benefit (credit) cost and amounts recognized in other comprehensive income and regulatory assets and liabilities for Dominion s and Dominion Gas (for employees represented by collective bargaining units) plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2015**	2014	2013	**2015**	2014	2013
(millions, except percentages)						
DOMINION						
Service cost	**$ 126**	$ 114	$ 131	**$ 40**	$ 32	$ 43
Interest cost	**287**	290	271	**67**	67	73
Expected return on plan assets	**(531)**	(499)	(462)	**(117)**	(111)	(92)
Amortization of prior service (credit) cost	**2**	3	3	**(27)**	(28)	(15)
Amortization of net actuarial loss	**160**	111	165	**6**	2	7
Settlements and curtailments(1)		1	(2)			(15)
Special termination benefits						1
Net periodic benefit (credit) cost	**$ 44**	$ 20	$ 106	**$ (31)**	$ (38)	$ 2
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 159**	$ 784	$ (968)	**$ (18)**	$ 183	$ (255)
Prior service (credit) cost			1	**(31)**	9	(215)
Settlements and curtailments(1)		(1)	(22)			(7)
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(160)**	(111)	(165)	**(6)**	(2)	(7)
Amortization of prior service credit (cost)	**(2)**	(3)	(3)	**27**	28	15
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ (3)**	$ 669	$ (1,157)	**$ (28)**	$ 218	$ (469)
Significant assumptions used to determine periodic cost:						
Discount rate	**4.40%**	5.20%-5.30%	4.40%-4.80%	**4.40%**	4.20%-5.10%	4.40%-4.80%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.50%	**8.50%**	8.50%	7.75%
Weighted average rate of increase for compensation	**4.22%**	4.21%	4.21%	**4.22%**	4.22%	4.22%
Healthcare cost trend rate(2)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(2)				**5.00%**	5.00%	4.60%
Year that the rate reaches the ultimate trend rate(2)(3)				**2019**	2018	2062
DOMINION GAS						
Service cost	**$ 15**	$ 12	$ 13	**$ 7**	$ 6	$ 7
Interest cost	**27**	28	27	**14**	13	12
Expected return on plan assets	**(126)**	(115)	(106)	**(24)**	(23)	(19)
Amortization of prior service (credit) cost	**1**	1	1	**(1)**	(1)	(3)
Amortization of net actuarial loss	**20**	19	26	**2**		2
Net periodic benefit (credit) cost	**$ (63)**	$ (55)	$ (39)	**$ (2)**	$ (5)	$ (1)
Changes in plan assets and benefit obligations recognized in other comprehensive income						

and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 97**	$ 43	$ (127)	**$ (9)**	$ 40	$ (40)
Prior service cost					10	
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(20)**	(19)	(26)	**(2)**		(2)
Amortization of prior service credit (cost)	**(1)**	(1)	(1)	**1**	1	3
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ 76**	$ 23	$ (154)	**$ (10)**	$ 51	$ (39)
Significant assumptions used to determine periodic cost:						
Discount rate	**4.40%**	5.20%	4.40%-4.80%	**4.40%**	4.20%-5.00%	4.40%-4.70%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.50%	**8.50%**	8.50%	7.75%
Weighted average rate of increase for compensation	**3.93%**	3.93%	3.93%	**3.93%**	3.93%	3.93%
Healthcare cost trend rate(2)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(2)				**5.00%**	5.00%	4.60%
Year that the rate reaches the ultimate trend rate(2)(3)				**2019**	2018	2062

(1) 2013 amounts relate primarily to the decommissioning of Kewaunee.
(2) Assumptions used to determine net periodic cost for the following year.
(3) The Society of Actuaries model used to determine healthcare cost trend rates was updated in 2014. The new model converges to the ultimate trend rate much more quickly than previous models.

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Combined Notes to Consolidated Financial Statements, Continued

The components of AOCI and regulatory assets and liabilities for Dominion s and Dominion Gas (for employees represented by collective bargaining units) plans that have not been recognized as components of net periodic benefit (credit) cost are as follows:

At December 31,	Pension Benefits		Other Postretirement Benefits	
(millions)	**2015**	2014	**2015**	2014
DOMINION				
Net actuarial loss	**$ 2,381**	$ 2,382	**$ 114**	$ 139
Prior service (credit) cost	**5**	7	**(237)**	(233)
Total(1)	**$ 2,386**	$ 2,389	**$ (123)**	$ (94)
DOMINION GAS				
Net actuarial loss	**$ 380**	$ 303	**$ 33**	$ 43
Prior service (credit) cost	**1**	1	**7**	7
Total(2)	**$ 381**	$ 304	**$ 40**	$ 50

(1) As of December 31, 2015, of the $2.4 billion and $(123) million related to pension benefits and other postretirement benefits, $1.4 billion and $(90) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities. As of December 31, 2014, of the $2.4 billion and $(94) million related to pension benefits and other postretirement benefits, $1.4 billion and $(81) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

(2) As of December 31, 2015, of the $381 million related to pension benefits, $138 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $40 million related to other postretirement benefits is included entirely in regulatory assets and liabilities. As of December 31, 2014, of the $304 million related to pension benefits, $112 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $50 million related to other postretirement benefits is included entirely in regulatory assets and liabilities.

The following table provides the components of AOCI and regulatory assets and liabilities for Dominion s and Dominion Gas (for employees represented by collective bargaining units) plans as of December 31, 2015 that are expected to be amortized as components of net periodic benefit (credit) cost in 2016:

(millions)	Pension Benefits	Other Postretirement Benefits
DOMINION		
Net actuarial loss	**$ 111**	**$ 5**
Prior service (credit) cost	**1**	**(28)**
DOMINION GAS		
Net actuarial loss	**$ 13**	**$ 1**
Prior service (credit) cost		**1**

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality are critical assumptions in determining net periodic benefit (credit) cost. Dominion develops assumptions, which are then compared to the forecasts of an independent investment advisor (except for the expected long-term rates of return) to ensure reasonableness. An internal committee selects the final assumptions used for Dominion s pension and other postretirement plans, including those in which Dominion Gas participates, including discount rates, expected long-term rates of return, healthcare cost trend rates and mortality rates.

Dominion determines the expected long-term rates of return on plan assets for its pension plans and other postretirement benefit plans, including those in which Dominion Gas participates, by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forecasts of an independent investment advisor;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets.

Dominion determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans, including those in which Dominion Gas participates.

Dominion develops its mortality assumption using plan-specific studies and projects mortality improvement using scales developed by the Society of Actuaries for all its plans, including those in which Dominion Gas participates.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for Dominion s retiree healthcare plans, including those in which Dominion Gas participates. A one percentage point change in assumed healthcare cost trend rates would have had the following effects for Dominion s and Dominion Gas (for employees represented by collective bargaining units) other postretirement benefit plans:

	Other Postretirement Benefits	
(millions)	One percentage point increase	One percentage point decrease
DOMINION		
Effect on net periodic cost for 2016	**$ 21**	**$ (13)**
Effect on other postretirement benefit obligation at December 31, 2015	**157**	**(129)**
DOMINION GAS		
Effect on net periodic cost for 2016	**$ 5**	**$ (3)**
Effect on other postretirement benefit obligation at December 31, 2015	**34**	**(26)**

Dominion Gas (Employees Not Represented by Collective Bargaining Units) and Virginia Power-Participation in Defined Benefit Plans

Virginia Power employees and Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan described above. As participating employers, Virginia Power and Dominion Gas are subject to Dominion s funding policy, which is to contribute annually an amount that is in accordance with ERISA. During 2015, Virginia Power and Dominion Gas made no contributions to the Dominion Pension Plan, and no contributions to this plan are currently expected in 2016. Virginia Power s net periodic pension cost related to this plan was $97 million, $75 million and $96 million in 2015, 2014 and 2013, respectively. Dominion Gas net periodic pension credit related to this plan was $(38) million, $(37) million and $(27) million in 2015, 2014 and 2013, respectively. Net periodic pension (credit) cost is reflected in other operations and maintenance expense in their respective Consolidated Statements of Income. The funded status of various Dominion subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Retiree healthcare and life insurance benefits, for Virginia Power employees and for Dominion Gas employees not represented by collective bargaining units, are covered by the Dominion Retiree Health and Welfare Plan described above. Virginia Power s net periodic benefit (credit) cost related to this plan was $(16) million, $(18) million and $5 million in 2015, 2014 and 2013, respectively. Dominion Gas net periodic benefit (credit) cost related to this plan was $(5) million, $(5) million and less than $1 million for 2015, 2014 and 2013, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expenses in their respective Consolidated Statements of Income. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating Dominion subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Dominion holds investments in trusts to fund employee benefit payments for the pension and other postretirement benefit plans in which Virginia Power and Dominion Gas employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that Virginia Power and Dominion Gas will provide to Dominion for their shares of employee benefit plan contributions.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, Virginia Power and Dominion Gas fund other postretirement benefit costs through VEBAs. During 2015 and 2014, Virginia Power made no contributions to the VEBA and does not expect to contribute to the VEBA in 2016. Dominion Gas made no contributions to the VEBAs for employees not represented by collective bargaining units during 2015 and does not expect to contribute in 2016. Dominion Gas contributions to VEBAs for employees not represented by collective bargaining units were $1 million for 2014.

Defined Contribution Plans

Dominion also sponsors defined contribution employee savings plans that cover substantially all employees. During 2015, 2014 and 2013, Dominion recognized $43 million, $41 million and $40 million, respectively, as employer matching contributions to these plans. Dominion Gas participates in these employee savings plans, both specific to Dominion Gas and that cover multiple Dominion subsidiaries. During 2015, 2014 and 2013, Dominion Gas recognized $7 million as employer matching contributions to these plans. Virginia Power also participates in these employee savings plans. During 2015, 2014 and 2013, Virginia Power recognized $18 million, $17 million and $16 million, respectively, as employer matching contributions to these plans.

NOTE 22. COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the ordinary course of business, the Companies are involved in legal proceedings before various courts and are periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for the Companies to estimate a range of possible loss. For such matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that the Companies are able to estimate a range of possible loss. For legal proceedings and governmental examinations for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the Companies maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial position, liquidity or results of operations of the Companies.

Environmental Matters

The Companies 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.

Air

CAA

The CAA, as amended, is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation s air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies facilities are subject to the CAA s permitting and other requirements.

MATS

In December 2011, the EPA issued MATS for coal and oil-fired electric utility steam generating units. The rule establishes strict emission limits for mercury, particulate matter as a surrogate for toxic metals and hydrogen chloride as a surrogate for acid gases. The rule includes a limited use provision for oil-fired units with annual capacity factors under 8% that provides an exemption from emission limits, and allows compliance with operational work practice standards. Compliance was required by April 16, 2015, with certain limited exceptions. However, in June 2014,

the Virginia Department of Environmental Quality granted a one-year MATS compliance extension for two coal-fired units at Yorktown to defer planned retirements and allow for continued operation of the units to address reliability concerns while necessary electric transmission upgrades are being completed. These coal units will need to continue operating until at least April 2017 due to delays in transmission upgrades needed to maintain electric reliability, which based on assumptions about the timing for required agency actions and construction schedules are expected to be completed by no earlier than the second quarter of 2017. Therefore, in October 2015 Virginia Power submitted a request to the EPA for an additional one year compliance extension under an EPA Administrative Order.

In June 2015, the U.S. Supreme Court issued a decision holding that the EPA failed to take cost into account when the agency first decided to regulate the emissions from coal- and oil-fired plants, and remanded the MATS rule back to the D.C. Circuit Court. However, the Supreme Court did not vacate or stay the effective date and implementation of the MATS rule. On November 20, 2015, in response to the Supreme Court decision, the EPA proposed a supplemental finding that consideration of cost does not alter the agency s previous conclusion that it is appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units under Section 112 of the CAA. On December 15, 2015, the D.C. Court of Appeals issued an order remanding the MATS rulemaking proceeding back to the EPA without setting aside judgment, noting that EPA had represented it was on track to issue by April 15, 2016, a final finding regarding its consideration of cost. These actions do not change Virginia Power s plans to close coal units at Yorktown or the need to complete necessary electricity transmission upgrades by 2017. Since the MATS rule remains in effect and Dominion is complying with the requirements of the rule, Dominion does not expect any adverse impacts to its operations at this time.

CAIR

The EPA established CAIR with the intent to require significant reductions in SO_2 and NO_x emissions from electric generating facilities. In July 2008, the U.S. Court of Appeals for the D.C. Circuit issued a ruling vacating CAIR. In December 2008, the Court denied rehearing, but also issued a decision to remand CAIR to the EPA. In July 2011, the EPA issued a replacement rule for CAIR, called CSAPR, that required 28 states to reduce power plant emissions that cross state lines. CSAPR established new SO_2 and NO_X emissions cap and trade programs that were completely independent of the current ARP. Specifically, CSAPR required reductions in SO_2 and NO_X emissions from fossil fuel-fired electric generating units of 25 MW or more through annual NO_X emissions caps, NO_X emissions caps during the ozone season (May 1 through September 30) and annual SO_2 emission caps with differing requirements for two groups of affected states.

CSAPR

Following numerous petitions by industry participants for review and a successful motion for stay, in October 2014, the

U.S. Court of Appeals for the D.C. Circuit ordered that the EPA s motion to lift the stay of CSAPR be granted. Further, the Court granted the EPA s request to shift the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets (which would have gone into effect in 2012 and 2013) will apply in 2015 and 2016, and Phase 2 emissions budgets will apply in 2017 and beyond. CSAPR replaced CAIR beginning in January 2015. The cost to comply is not expected to be material to the Consolidated Financial Statements. Future outcomes of any additional litigation and/or any action to issue a revised rule could affect the assessment regarding cost of compliance.

Ozone Standards

In October 2015, the EPA issued a final rule tightening the ozone standard from 75-ppb to 70-ppb. The EPA is expected to complete attainment designations for a new standard by December 2017 and states will have until 2020 or 2021 to develop plans to address the new standard. Until the states have developed implementation plans, the Companies are unable to predict whether or to what extent the new rules will ultimately require additional controls. However, if significant expenditures are required to implement additional controls, it could adversely affect the Companies results of operations and cash flows.

Hazardous Air Pollutants Standards

In August 2010, the EPA issued revised National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, which was amended in March 2011 and January 2013. The rule establishes emission standards for control of hazardous air pollutants for engines at smaller facilities, known as area sources. As a result of these regulations, Dominion Gas has spent $2 million to install emissions controls on several compressor engines. Further capital spending is not expected to be material.

NSPS

In August 2012, the EPA issued the first NSPS impacting the natural gas production and gathering sectors and made revisions to the NSPS for natural gas processing and transmission facilities. These rules establish equipment performance specifications and emissions standards for control of VOC emissions for natural gas production wells, tanks, pneumatic controllers, and compressors in the upstream sector. In September 2015, the EPA issued a proposed NSPS to regulate methane and VOC emissions from transmission and storage, gathering and boosting, production and processing facilities. All projects which commence construction after September 2015 will be required to comply with this regulation. Dominion is evaluating the proposed regulation and cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

Methane Emissions

In January 2015, as part of its Climate Action Plan, the EPA announced plans to reduce methane emissions from the oil and gas sector including natural gas processing and transmission sources. In July 2015, the EPA announced the next generation of its voluntary Natural Gas STAR program, the Natural Gas STAR Methane Challenge Program. The proposed program covers the entire natural gas sector from production to distribution, with

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more emphasis on transparency and increased reporting for both annual emissions and reductions achieved through implementation measures. Dominion is evaluating the proposed program and cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

Climate Change Legislation and Regulation

In October 2013, the U.S. Supreme Court granted petitions filed by several industry groups, states, and the U.S. Chamber of Commerce seeking review of the D.C. Circuit Court s June 2012 decision upholding the EPA s regulation of GHG emissions from stationary sources under the CAA s permitting programs. In June 2014, the U.S. Supreme Court ruled that the EPA lacked the authority under the CAA to require PSD or Title V permits for stationary sources based solely on GHG emissions. However, the Court upheld the EPA s ability to require BACT for GHG for sources that are otherwise subject to PSD or Title V permitting for conventional pollutants. In July 2014, the EPA issued a memorandum specifying that it will no longer apply or enforce federal regulations or EPA-approved PSD state implementation plan provisions that require new and modified stationary sources to obtain a PSD permit when GHGs are the only pollutant that would be emitted at levels that exceed the permitting thresholds. In August 2015, the EPA published a final rule rescinding the requirement for all new and modified major sources to obtain permits based solely on their GHG emissions. In addition, the EPA stated that it will continue to use the existing thresholds to apply to sources that are otherwise subject to PSD for conventional pollutants until it completes a new rulemaking either justifying and upholding those thresholds or setting new ones. Some states have issued interim guidance that follows the EPA guidance. Due to uncertainty regarding what additional actions states may take to amend their existing regulations and what action the EPA ultimately takes to address the Court ruling under a new rulemaking, the Companies cannot predict the impact to their financial statements at this time.

In July 2011, the EPA signed a final rule deferring the need for PSD and Title V permitting for CO_2 emissions for biomass projects. This rule temporarily deferred for a period of up to three years the consideration of CO_2 emissions from biomass projects when determining whether a stationary source meets the PSD and Title V applicability thresholds, including those for the application of BACT. The deferral policy expired in July 2014. In July 2013, the U.S. Court of Appeals for the D.C. Circuit vacated this rule; however, a mandate making this decision effective has not been issued. Virginia Power converted three coal-fired generating stations, Altavista, Hopewell and Southampton, to biomass during the CO_2 deferral period. It is unclear how the court s decision or the EPA s final policy regarding the treatment of specific feedstock will affect biomass sources that were permitted during the deferral period; however, the expenditures to comply with any new requirements could be material to Dominion s and Virginia Power s financial statements.

Water

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong

enforcement mechanisms. The Companies must comply with applicable aspects of the CWA programs at their operating facilities.

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. Dominion and Virginia Power have 14 and 11 facilities, respectively, that may be subject to the final regulations. Dominion anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion and Virginia Power are currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost and benefit studies. While the impacts of this rule could be material to Dominion s and Virginia Power s results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

In September 2015, the EPA released a final rule to revise the Effluent Limitations Guidelines for the Steam Electric Power Generating Category. The final rule establishes updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. Virginia Power has eight facilities that may be subject to additional wastewater treatment requirements associated with the final rule. The expenditures to comply with these new requirements are expected to be material.

Solid and Hazardous Waste

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under the CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

Combined Notes to Consolidated Financial Statements, Continued

From time to time, Dominion, Virginia Power, or Dominion Gas may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or conduct the remedial investigation and action itself and then seek reimbursement from the potentially responsible parties. Each party can be held jointly, severally and strictly liable for the cleanup costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion, Virginia Power, or Dominion Gas may be responsible for the costs of remedial investigation and actions under the Superfund law or other laws or regulations regarding the remediation of waste. Except as noted below, the Companies do not believe this will have a material effect on results of operations, financial condition and/or cash flows.

In September 2011, the EPA issued a UAO to Virginia Power and 22 other parties, ordering specific remedial action of certain areas at the Ward Transformer Superfund site located in Raleigh, North Carolina. Virginia Power does not believe it is a liable party under CERCLA based on its alleged connection to the site. In November 2011, Virginia Power and a number of other parties notified the EPA that they are declining to undertake the work set forth in the UAO.

The EPA may seek to enforce a UAO in court pursuant to its enforcement authority under CERCLA, and may seek recovery of its costs in undertaking removal or remedial action. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party s failure to comply with the UAO. Virginia Power is currently unable to make an estimate of the potential financial statement impacts related to the Ward Transformer matter.

Dominion has determined that it is associated with 17 former manufactured gas plant sites, three of which pertain to Virginia Power and 12 of which pertain to Dominion Gas. Studies conducted by other utilities at their former manufactured gas plant sites have indicated that those sites contain coal tar and other potentially harmful materials. None of the former sites with which the Companies are associated is under investigation by any state or federal environmental agency. At one of the former sites, Dominion is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Another site has been accepted into a state-based voluntary remediation program. Virginia Power is currently evaluating the nature and extent of the contamination from this site as well as potential remedial options. Preliminary costs for options under evaluation for the site range from $1 million to $22 million. Due to the uncertainty surrounding the other sites, the Companies are unable to make an estimate of the potential financial statement impacts.

See below for discussion on ash pond and landfill closure costs.

Other Legal Matters

The Companies are defendants in a number of lawsuits and claims involving unrelated incidents of property damage and personal injury. Due to the uncertainty surrounding these matters, the Companies are unable to make an estimate of the potential financial statement impacts; however, they could have a material impact on results of operations, financial condition and/or cash flows.

Appalachian Gateway

Following the completion of the Appalachian Gateway project in 2012, DTI received multiple change order requests and other claims for additional payments from a pipeline contractor for the project. In July 2013, DTI filed a complaint in U.S. District Court for the Eastern District of Virginia for breach of contract as well as accounting and declaratory relief. The contractor filed a motion to dismiss, or in the alternative, a motion to transfer venue to Pennsylvania and/or West Virginia, where the pipelines were constructed. DTI filed an opposition to the contractor s motion in August 2013. In November 2013, the court granted the contractor s motion on the basis that DTI must first comply with the dispute resolution process. In July 2015, the contractor filed a complaint against DTI in U.S. District Court for the Western District of Pennsylvania. In August 2015, DTI filed a motion to dismiss, or in the alternative, a motion to transfer venue to Virginia. This case is pending. DTI has accrued a liability of $6 million for this matter. Dominion Gas cannot currently estimate additional financial statement impacts, but there could be a material impact to its financial condition and/or cash flows.

Ash Pond and Landfill Closure Costs

In September 2014, Virginia Power received a notice from the SELC on behalf of the Potomac Riverkeeper and Sierra Club alleging CWA violations at Possum Point. The notice alleges unpermitted discharges to surface water and groundwater from Possum Point s historical and active ash storage facilities. A similar notice from the SELC on behalf of the Sierra Club was subsequently received related to Chesapeake. In December 2014, Virginia Power offered to close all of its coal ash ponds and landfills at Possum Point, Chesapeake and Bremo as settlement of the potential litigation. While the issue is open to potential further negotiations, the SELC declined the offer as presented in January 2015 and, in March 2015, filed a lawsuit related to its claims of the alleged CWA violations at Chesapeake. Virginia Power filed a motion to dismiss in April 2015, which was denied in November 2015. As a result of the December 2014 settlement offer, Virginia Power recognized a charge of $121 million in other operations and maintenance expense in its Consolidated Statements of Income in the Companies Annual Report on Form 10-K for the year ended December 31, 2014.

In April 2015, the EPA s final rule regulating the management of CCRs stored in impoundments (ash ponds) and landfills was published in the Federal Register. The final rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store CCRs. Virginia Power currently operates inactive ash ponds, existing ash ponds, and CCR landfills subject to the final rule at eight different facilities. The enactment of the final rule in April 2015 created a legal obligation for Virginia Power to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary. In 2015, Virginia Power recorded a $386 million ARO related to future ash pond and landfill closure costs. Recognition of the ARO also resulted in a $99 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $166 million increase in property, plant, and equipment associated with asset retirement costs, and a $121 million reduction in other noncurrent liabilities related to reversal of the contingent liability described above since the ARO obligation created by the final CCR rule represents similar activities. Virginia Power is in the process of obtaining the necessary permits to complete the work. The actual AROs related to the CCR rule may vary substantially from the estimates used to record the increased obligation in 2015.

Cove Point

Dominion is constructing the Liquefaction Project at the Cove Point facility, which would enable the facility to liquefy domestically-produced natural gas and export it as LNG. In September 2014, FERC issued an order granting authorization for Cove Point to construct, modify and operate the Liquefaction Project. In October 2014, several parties filed a motion with FERC to stay the order and requested rehearing. In May 2015, FERC denied the requests for stay and rehearing.

Two parties have separately filed petitions for review of the FERC order in the U.S. Court of Appeals for the D.C. Circuit, which petitions have been consolidated. Separately, one party requested a stay of the FERC order until the judicial proceedings are complete, which the court denied in June 2015.

In May 2014, the Maryland Commission granted the CPCN authorizing the construction of a generating station in connection with the Liquefaction Project. The CPCN obligates Cove Point to make payments totaling $48 million. These payments consist of $40 million to the Strategic Energy Investments Fund over a five-year period beginning in 2015 and $8 million to Maryland low income energy assistance programs over a twenty-year period expected to begin in 2018. In December 2014, upon receipt of applicable approvals to commence construction of the generating station, Dominion recorded the present value of the obligation as an increase to property, plant and equipment and a corresponding liability.

In June 2014, a party filed a notice of petition for judicial review of the CPCN with the Circuit Court for Baltimore City in Maryland. In September 2014, the party filed with the Maryland Commission a motion to stay the CPCN pending judicial review of the CPCN. In December 2014, the Circuit Court issued an order affirming the Maryland Commission s grant of the CPCN and dismissing the appeal, and the motion for stay was denied by the Maryland Commission. In January 2015, the same party filed a Notice of Appeal of the Baltimore Circuit Court s Order affirming the Maryland Commission s grant of the CPCN with the Court of Special Appeals of Maryland. In February 2016, the Court of Special Appeals of Maryland issued an order affirming the judgment of the Circuit Court for Baltimore City in Maryland which affirmed the decision of the Maryland Commission granting the CPCN.

Nuclear Matters

In March 2011, a magnitude 9.0 earthquake and subsequent tsunami caused significant damage at the Fukushima Daiichi nuclear power station in northeast Japan. These events have resulted in significant nuclear safety reviews required by the NRC and industry groups such as INPO. Like other U.S. nuclear operators, Dominion has been gathering supporting data and participating in industry initiatives focused on the ability to respond to

and mitigate the consequences of design-basis and beyond-design-basis events at its stations.

In July 2011, an NRC task force provided initial recommendations based on its review of the Fukushima Daiichi accident and in October 2011 the NRC staff prioritized these recommendations into Tiers 1, 2 and 3, with the Tier 1 recommendations consisting of actions which the staff determined should be started without unnecessary delay. In December 2011, the NRC Commissioners approved the agency staff s prioritization and recommendations, and that same month an appropriations act directed the NRC to require reevaluation of external hazards (not limited to seismic and flooding hazards) as soon as possible.

Based on the prioritized recommendations, in March 2012, the NRC issued orders and information requests requiring specific reviews and actions to all operating reactors, construction permit holders and combined license holders based on the lessons learned from the Fukushima Daiichi event. The orders applicable to Dominion requiring implementation of safety enhancements related to mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, and enhancing spent fuel pool instrumentation have been implemented. The information requests issued by the NRC request each reactor to reevaluate the seismic and external flooding hazards at their site using present-day methods and information, conduct walkdowns of their facilities to ensure protection against the hazards in their current design basis, and to reevaluate their emergency communications systems and staffing levels. The walkdowns of each unit have been completed, audited by the NRC and found to be adequate. Reevaluation of the seismic and external flooding hazards is expected to continue through 2018. Dominion and Virginia Power do not currently expect that compliance with the NRC s information requests will materially impact their financial position, results of operations or cash flows during the implementation period. The NRC staff is evaluating the implementation of the longer term Tier 2 and Tier 3 recommendations. Dominion and Virginia Power are currently unable to estimate the potential financial impacts related to compliance with Tier 2 and Tier 3 recommendations.

Nuclear Operations

NUCLEAR DECOMMISSIONING MINIMUM FINANCIAL ASSURANCE

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. The 2015 calculation for the NRC minimum financial assurance amount, aggregated for Dominion s and Virginia Power s nuclear units, excluding joint owners assurance amounts and Millstone Unit 1 and Kewaunee, as those units are in a decommissioning state, was $2.9 billion and $1.8 billion, respectively, 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. The 2015 NRC minimum financial assurance amounts above were calculated using preliminary December 31, 2015 U.S. Bureau of Labor Statistics indices. Dominion believes that the

Combined Notes to Consolidated Financial Statements, Continued

amounts currently available in its decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Virginia Power also believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects a positive long-term outlook for trust fund investment returns as the decommissioning of the units will not be complete for decades. Dominion and Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirement, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. See Note 9 for additional information on nuclear decommissioning trust investments.

Nuclear Insurance

The Price-Anderson Amendments Act of 1988 provides the public up to $13.5 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and allows for an inflationary provision adjustment every five years. Dominion and Virginia Power have purchased $375 million of coverage from commercial insurance pools for each reactor site with the remainder provided through a mandatory industry retrospective rating plan. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., the Companies could be assessed up to $127 million for each of their licensed reactors not to exceed $19 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. However, the NRC granted an exemption in March 2015 to remove Kewaunee from the Secondary Financial Protection program.

The current levels of nuclear property insurance coverage for Dominion s and Virginia Power s nuclear units is as follows:

(billions)	Coverage
Dominion	
Millstone	**$ 1.70**
Kewaunee	**1.06**
Virginia Power(1)	
Surry	**$ 1.70**
North Anna	**1.70**

(1) Surry and North Anna share a blanket property limit of $200 million.

Dominion s and Virginia Power s nuclear property insurance coverage for Millstone, Surry and North Anna exceeds the NRC minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site. Kewaunee meets the NRC minimum requirement of $1.06 billion. This 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. Nuclear property insurance is provided by 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. Dominion s and Virginia Power s maximum retrospective

premium assessment for the current policy period is $84 million and $48 million, respectively. Based on the severity of the incident, the Board of Directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. Dominion and Virginia Power 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.

Millstone and Virginia Power also purchase accidental outage insurance from NEIL to mitigate certain expenses, including replacement power costs, associated with the prolonged outage of a nuclear unit due to direct physical damage. Under this program, Dominion and Virginia Power are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. Dominion s and Virginia Power s maximum retrospective premium assessment for the current policy period is $23 million and $10 million, respectively.

ODEC, a part owner of North Anna, and Massachusetts Municipal and Green Mountain, part owners of Millstone s Unit 3, are responsible to Dominion and Virginia Power 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

Dominion and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel under provisions of the Nuclear Waste Policy Act of 1982. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by Dominion s and Virginia Power s contracts with the DOE. Dominion and Virginia Power have previously received damages award payments and settlement payments related to these contracts.

In 2012, Dominion and Virginia Power resolved additional claims for damages incurred at Millstone, Kewaunee, Surry and North Anna with the Authorized Representative of the Attorney General. Dominion and Virginia Power entered into settlement agreements that resolved claims for damages incurred through December 31, 2010, and also provided for periodic payments after that date for damages incurred through December 31, 2013.

By mutual agreement of the parties, the settlement agreements are extendable to provide for resolution of damages incurred after 2013. The settlement agreements for the Surry, North Anna and Millstone plants have been extended to provide for periodic payments for damages incurred through December 31, 2016. Possible extension of the Kewaunee settlement agreement is being evaluated.

In 2015, Virginia Power and Dominion received payments of $8 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2013 through December 31, 2013, and $17 million for resolution of claims incurred at Millstone for the period of July 1, 2013 through June 30, 2014.

In 2014, Virginia Power and Dominion received payments of $27 million for the resolution of claims incurred at North Anna and Surry for the period January 1, 2011 through December 31, 2012 and $17 million for the resolution of claims incurred at Millstone for the period of July 1, 2012 through June 30, 2013. In 2014, Dominion also received payments totaling $7 million for the resolution of claims incurred at Kewaunee for periods from January 1, 2011 through December 31, 2013.

Dominion and Virginia Power continue to recognize receivables for certain spent nuclear fuel-related costs that they believe are probable of recovery from the DOE. Dominion s receivables for spent nuclear fuel-related costs totaled $87 million and $69 million at December 31, 2015 and 2014, respectively. Virginia Power s receivables for spent nuclear fuel-related costs totaled $54 million and $41 million at December 31, 2015 and 2014, respectively.

Pursuant to a November 2013 decision of the U.S Court of Appeals for the D.C. Circuit, in January 2014 the Secretary of the DOE sent a recommendation to the U.S. Congress to adjust to zero the current fee of $1 per MWh for electricity paid by civilian nuclear power generators for disposal of spent nuclear fuel. The processes specified in the Nuclear Waste Policy Act for adjustment of the fee have been completed, and as of May 2014, Dominion and Virginia Power are no longer required to pay the waste fee. In 2014, Dominion and Virginia Power recognized fees of $16 million and $10 million, respectively.

Dominion and Virginia Power will continue to manage their spent fuel until it is accepted by the DOE.

Long-Term Purchase Agreements

At December 31, 2015, Virginia Power had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

(millions)	2016	2017	2018	2019	2020	Thereafter	Total
Purchased electric capacity(1)	**$ 249**	**$ 157**	**$ 104**	**$ 65**	**$ 52**	**$ 46**	**$ 673**

(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, 2015, the present value of Virginia Power s total commitment for capacity payments is $577 million. Capacity payments totaled $305 million, $330 million, and $345 million, and energy payments totaled $198 million, $304 million, and $236 million for the years ended 2015, 2014 and 2013, respectively.

Lease Commitments

The Companies lease various facilities, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2015 are as follows:

(millions)	2016	2017	2018	2019	2020	Thereafter	Total
Dominion	**$ 67**	**$ 62**	**$ 54**	**$ 43**	**$ 25**	**$ 153**	**$ 404**
Virginia Power	**$ 30**	**$ 27**	**$ 23**	**$ 17**	**$ 14**	**$ 27**	**$ 138**
Dominion Gas	**$ 26**	**$ 25**	**$ 23**	**$ 18**	**$ 6**	**$ 19**	**$ 117**

Rental expense for Dominion totaled $99 million, $92 million, and $101 million for 2015, 2014 and 2013, respectively. Rental expense for Virginia Power totaled $51 million, $43 million, and $42 million for 2015, 2014, and 2013, respectively. Rental expense for Dominion Gas totaled $37 million, $35 million and $15 million for 2015, 2014 and 2013, respectively. The majority of rental expense is reflected in other operations and maintenance expense in the Consolidated Statements of Income.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2015, Dominion had issued $74 million of guarantees, primarily to support equity method investees. No significant amounts related to these guarantees have been recorded. As of December 31, 2015, Dominion s exposure under these guarantees was $39 million, primarily related to certain reserve requirements associated with non-recourse financing.

Dominion also enters into guarantee arrangements on behalf of its 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 Dominion s consolidated subsidiaries, that liability is included in the Consolidated Financial Statements. Dominion is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Terms of the guarantees typically end once obligations have been paid. Dominion currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries obligations.

At December 31, 2015, Dominion had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value[(1)]
Subsidiary debt[(2)]	**$ 27**	**$ 27**
Commodity transactions[(3)]	**2,371**	**932**
Nuclear obligations[(4)]	**184**	**75**
Cove Point[(5)]	**1,910**	
Solar[(6)]	**1,555**	**647**
Other[(7)]	**515**	**31**
Total	**$ 6,562**	**$ 1,712**

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of December 31, 2015 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 Dominion s subsidiaries, the value includes the recorded amount.

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(2) Guarantee of debt of a DEI subsidiary. In the event of default by the subsidiary, Dominion would be obligated to repay such amounts.
(3) Guarantees related to commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power, Dominion Gas 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, Dominion would be obligated to satisfy such obligation. Dominion and its subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.
(4) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under Dominion s nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. Excludes Dominion s agreement to provide up to $150 million and $60 million to two DEI subsidiaries to pay the operating expenses of Millstone (in the event of a prolonged outage) and Kewaunee, respectively, as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of nuclear power stations. The agreement for Kewaunee also provides for funds through the completion of decommissioning.
(5) Guarantees related to Cove Point, in support of terminal services, transportation and construction. Two of the guarantees have no stated limit, one guarantee has a $150 million limit, and one guarantee has a $1.75 billion aggregate limit with an annual draw limit of $175 million.
(6) Includes guarantees to facilitate the development of solar projects including guarantees that do not have stated limits. Also includes guarantees entered into by DEI on behalf of certain subsidiaries to facilitate the acquisition and development of solar projects.
(7) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations and construction projects. Also includes guarantees related to certain DEI subsidiaries obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower. As of December 31, 2015, Dominion s maximum remaining cumulative exposure under these equity funding agreements is $55 million through 2019 and its maximum annual future contributions could range from approximately $4 million to $19 million. The value provided includes certain guarantees that do not have stated limits.

Additionally, at December 31, 2015, Dominion had purchased $92 million of surety bonds, including $34 million at Virginia Power and $23 million at Dominion Gas, and authorized the issuance of letters of credit by financial institutions of $59 million to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

As of December 31, 2015, Virginia Power had issued $14 million of guarantees primarily to support tax-exempt debt issued through conduits. The related debt matures in 2031 and is included in long-term debt in Virginia Power s Consolidated Balance Sheets. In the event of default by a conduit, Virginia Power would be obligated to repay such amounts, which are limited to the principal and interest then outstanding.

Indemnifications

As part of commercial contract negotiations in the normal course of business, the Companies 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. The Companies are unable to develop an estimate of the maximum potential amount of any other future payments under these contracts because events that

would obligate them have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence. However, at December 31, 2015, the Companies believe any other future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on their results of operations, cash flows or financial position.

NOTE 23. CREDIT RISK

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, credit policies are maintained, 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.

The Companies maintain a provision for credit losses based on factors surrounding the credit risk of their customers, historical trends and other information. Management believes, based on credit policies and the December 31, 2015 provision for credit losses, that it is unlikely that a material adverse effect on financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

General

Dominion

As a diversified energy company, Dominion transacts primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. Dominion does not believe that this geographic concentration contributes significantly to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion s exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion transacts with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. 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 any collateral. At December 31, 2015, Dominion s credit exposure totaled $149 million. Of this amount, investment grade counterparties, including those internally rated, represented 79%, and no single counterparty, whether investment grade or non-investment grade, exceeded $31 million of exposure.

Virginia Power

Virginia Power sells electricity and provides distribution and transmission services to customers in Virginia and northeastern

North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of Virginia Power s customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers. Virginia Power s exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Virginia Power s 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, 2015, Virginia Power s exposure to potential concentrations of credit risk was not considered material.

Dominion Gas

Dominion Gas transacts mainly with major companies in the energy industry and with residential and commercial energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. Dominion Gas does not believe that this geographic concentration contributes to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Gas is not exposed to a significant concentration of credit risk for receivables arising from gas utility operations.

In 2015, DTI provided service to 266 customers with approximately 94% of its storage and transportation revenue being provided through firm services. The ten largest customers provided approximately 42% of the total storage and transportation revenue and the thirty largest provided approximately 72% of the total storage and transportation revenue.

East Ohio distributes natural gas to residential, commercial and industrial customers in Ohio using rates established by the Ohio Commission. Approximately 98% of East Ohio revenues are derived from its regulated gas distribution services. East Ohio s bad debt risk is mitigated by the regulatory framework established by the Ohio Commission. See Note 13 for further information about Ohio s PIPP and UEX Riders that mitigate East Ohio s overall credit risk.

Credit-Related Contingent Provisions

The majority of Dominion s derivative instruments contain credit-related contingent provisions. These provisions require Dominion to provide collateral upon the occurrence of specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of December 31, 2015 and 2014, Dominion would have been required to post an additional $12 million and $20 million, respectively, of collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. Dominion had posted no collateral at December 31, 2015 and $1 million in collateral at December 31, 2014, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The

collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of December 31, 2015 and 2014 was $49 million, which does not include the impact of any offsetting asset positions. Credit-related contingent provisions for Virginia Power and Dominion Gas were not material as of December 31, 2015 and 2014. See Note 7 for further information about derivative instruments.

Note 24. Related-party Transactions

Virginia Power and Dominion Gas engage in related party transactions primarily with other Dominion subsidiaries (affiliates). Virginia Power s and Dominion Gas receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Virginia Power and Dominion Gas are included in Dominion s consolidated federal income tax return. See

Note 2 for further information. Dominion s transactions with equity method investments are described in Note 9. A discussion of significant related party transactions follows.

Virginia Power

Transactions with Affiliates

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risks associated with purchases of natural gas. See Notes 7 and 19 for more information. As of December 31, 2015, Virginia Power s derivative assets and liabilities with affiliates were $13 million and $22 million, respectively. As of December 31, 2014, Virginia Power s derivative assets and liabilities with affiliates were not material.

Virginia Power participates in certain Dominion benefit plans as described in Note 21. At December 31, 2015 and 2014, Virginia Power s amounts due to Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit liabilities in the Consolidated Balance Sheets were $316 million and $219 million, respectively. At December 31, 2015 and 2014, Virginia Power s amounts due from Dominion associated with the Dominion Retiree Health and Welfare Plan and reflected in other deferred charges and other assets in the Consolidated Balance Sheets were $77 million and $37 million, respectively.

DRS and other affiliates provide accounting, legal, finance and certain administrative and technical services to Virginia Power. In addition, Virginia Power provides certain services to affiliates, including charges for facilities and equipment usage.

Combined Notes to Consolidated Financial Statements, Continued

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31, (millions)	**2015**	2014	2013
Commodity purchases from affiliates	**$ 555**	$ 543	$ 417
Services provided by affiliates(1)	**422**	432	415
Services provided to affiliates	**22**	22	21

(1) Includes capitalized expenditures.

Virginia Power has borrowed funds from Dominion under short-term borrowing arrangements. There were $376 million and $427 million in short-term demand note borrowings from Dominion as of December 31, 2015 and 2014, respectively. Virginia Power had no outstanding borrowings, net of repayments under the Dominion money pool for its nonregulated subsidiaries as of December 31, 2015 and 2014. Interest charges related to Virginia Power s borrowings from Dominion were immaterial for the years ended December 31, 2015, 2014 and 2013.

There were no issuances of Virginia Power s common stock to Dominion in 2015, 2014 or 2013.

DOMINION GAS

Transactions with Related Parties

Dominion Gas transacts with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Dominion Gas provides transportation and storage services to affiliates. Dominion Gas also enters into certain other contracts with affiliates, which are presented separately from contracts involving commodities or services. As of December 31, 2015 and 2014, all of Dominion Gas commodity derivatives were with affiliates. See Notes 7 and 19 for more information. See Note 9 for information regarding sales of assets to an affiliate.

Dominion Gas participates in certain Dominion benefit plans as described in Note 21. At December 31, 2015 and 2014, Dominion Gas amounts due from Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $652 million and $614 million, respectively. At December 31, 2015 and 2014, Dominion Gas liabilities to Dominion associated with the Dominion Retiree Health and Welfare Plan and reflected in other deferred credits and other liabilities in the Consolidated Balance Sheets were $2 million and $7 million, respectively.

DRS and other affiliates provide accounting, legal, finance and certain administrative and technical services to Dominion Gas. Dominion Gas provides certain services to related parties, including technical services. The costs of these services follow:

Year Ended December 31, (millions)	**2015**	2014	2013
Purchases of natural gas and transportation and storage services from affiliates	**$ 10**	$ 34	$ 31
Sales of natural gas and transportation and storage services to affiliates	**69**	84	109
Services provided by related parties(1)	**133**	106	116
Services provided to related parties(2)	**101**	17	4

(1) Includes capitalized expenditures.
(2) Amounts primarily attributable to Atlantic Coast Pipeline.

The following table presents affiliated and related party activity reflected in Dominion Gas Consolidated Balance Sheets:

At December 31, (millions)	**2015**	2014
Other receivables[1]	**$ 7**	$ 17
Customer receivables from related parties	**4**	5
Imbalances receivable from affiliates[2]	**1**	3
Affiliated notes receivable[3]	**14**	9

(1) Represents amounts due from Atlantic Coast Pipeline, a related party VIE.
(2) Amounts are presented in other current assets in Dominion Gas Consolidated Balance Sheets.
(3) Amounts are presented in other deferred charges and other assets in Dominion Gas Consolidated Balance Sheets.

Dominion Gas borrowings under the IRCA with Dominion totaled $95 million and $384 million as of December 31, 2015 and 2014, respectively. Interest charges related to Dominion Gas total borrowings from Dominion were immaterial for the year ended December 31, 2015 and $4 million and $35 million for the years ended December 31, 2014 and 2013, respectively.

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NOTE 25. OPERATING SEGMENTS

The Companies are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion	Virginia Power	Dominion Gas
DVP	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Dominion Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Dominion Energy	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG import and storage	X		
	Nonregulated retail energy marketing(2)	X		

(1) Includes remaining producer services activities.
(2) As a result of Dominion s decision to realign its business units effective for 2015 year-end reporting, nonregulated retail energy marketing operations were moved from the Dominion Generation segment to the Dominion Energy segment.

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

Dominion

The Corporate and Other Segment of Dominion includes its corporate, service company and other functions (including unallocated debt) and the net impact of operations that are discontinued or sold. In addition, Corporate and Other includes specific items attributable to Dominion s operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

In March 2014, Dominion exited the electric retail energy marketing business. As a result, the earnings impact from the electric retail energy marketing business has been included in the Corporate and Other Segment of Dominion for 2014 first quarter results of operations.

In the second quarter of 2013, Dominion commenced a restructuring of its producer services business, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates. The restructuring, which was completed in the first quarter of 2014, resulted in the termination of natural gas trading and certain energy marketing activities. As a result, the earnings impact from natural gas trading and certain energy marketing activities has been included in the Corporate and Other Segment of Dominion for 2014.

In 2015, Dominion reported after-tax net expense of $391 million in the Corporate and Other segment, with $136 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Dominion Generation.

In 2014, Dominion reported after-tax net expense of $970 million in the Corporate and Other segment, with $544 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2014 primarily related to the impact of the following items:

- $374 million ($248 million after-tax) in charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, attributable to Dominion Generation;
- A $319 million ($193 million after-tax) net loss related to the producer services business discussed above, attributable to Dominion Energy; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

In 2013, Dominion reported after-tax net expense of $452 million in the Corporate and Other segment, with $184 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2013 primarily related to the impact of the following items:

- A $135 million ($92 million after-tax) net loss from discontinued operations of Brayton Point and Kincaid, including debt extinguishment of $64 million ($38 million after-tax) related to the sale, impairment charges of $48 million ($28 million after-tax), a $17 million ($18 million after-tax) loss on the sale which includes a $16 million write-off of goodwill, and a $6 million ($8 million after-tax) loss from operations, attributable to Dominion Generation; and
- A $182 million ($109 million after-tax) net loss, including a $55 million ($33 million after-tax) impairment charge related to certain natural gas infrastructure assets and a $127 million ($76 million after-tax) loss related to the producer services business discussed above, attributable to Dominion Energy; partially offset by
- An $81 million ($49 million after-tax) net gain on investments held in nuclear decommissioning trust funds, attributable to Dominion Generation.

Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion s operations:

Year Ended December 31, (millions)	DVP	Dominion Generation[(1)]	Dominion Energy[(1)]	Corporate and Other	Adjustments & Eliminations[(1)]	Consolidated Total
2015						
Total revenue from external customers	**$ 2,091**	**$ 7,001**	**$ 1,877**	**$ (27)**	**$ 741**	**$ 11,683**
Intersegment revenue	**20**	**15**	**695**	**554**	**(1,284)**	
Total operating revenue	**2,111**	**7,016**	**2,572**	**527**	**(543)**	**11,683**
Depreciation, depletion and amortization	**498**	**591**	**262**	**44**		**1,395**
Equity in earnings of equity method investees		**(15)**	**60**	**11**		**56**
Interest income		**64**	**25**	**13**	**(44)**	**58**
Interest and related charges	**230**	**262**	**27**	**429**	**(44)**	**904**
Income taxes	**307**	**465**	**423**	**(290)**		**905**
Net income (loss) attributable to Dominion	**490**	**1,120**	**680**	**(391)**		**1,899**
Investment in equity method investees		**245**	**1,042**	**33**		**1,320**
Capital expenditures	**1,607**	**2,190**	**2,153**	**43**		**5,993**
Total assets (billions)	**14.7**	**25.6**	**15.3**	**9.0**	**(5.8)**	**58.8**
2014						
Total revenue from external customers	$ 1,918	$ 7,135	$ 2,446	$ (12)	$ 949	$ 12,436
Intersegment revenue	18	34	880	572	(1,504)	
Total operating revenue	1,936	7,169	3,326	560	(555)	12,436
Depreciation, depletion and amortization	462	514	243	73		1,292
Equity in earnings of equity method investees		(18)	54	10		46
Interest income		58	23	20	(33)	68
Interest and related charges	205	240	11	770	(33)	1,193
Income taxes	317	365	463	(693)		452
Net income (loss) attributable to Dominion	502	1,061	717	(970)		1,310
Investment in equity method investees		262	796	23		1,081
Capital expenditures	1,652	2,466	1,329	104		5,551
Total assets (billions)	13.0	23.9	13.0	8.7	(4.3)	54.3
2013						
Total revenue from external customers	$ 1,825	$ 6,664	$ 3,566	$ 3	$ 1,062	$ 13,120
Intersegment revenue	9	283	739	609	(1,640)	
Total operating revenue	1,834	6,947	4,305	612	(578)	13,120
Depreciation, depletion and amortization	427	511	235	35		1,208
Equity in earnings of equity method investees		(14)	21	7		14
Interest income		59	19	42	(66)	54
Interest and related charges	175	220	26	522	(66)	877
Income taxes	287	436	456	(287)		892
Loss from discontinued operations, net of tax				(92)		(92)
Net income (loss) attributable to Dominion	475	963	711	(452)		1,697
Capital expenditures	1,361	1,605	1,043	95		4,104

(1) Amounts have been recast to reflect nonregulated retail energy marketing operations in the Dominion Energy segment.

Intersegment sales and transfers for Dominion are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

Virginia Power

The majority of Virginia Power s revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among Virginia Power s DVP and Dominion Generation segments.

The Corporate and Other Segment of Virginia Power primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments performance or allocating resources among the segments.

In 2015, Virginia Power reported after-tax net expenses of $153 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2015 primarily related to the impact of the following:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Dominion Generation.

In 2014, Virginia Power reported after-tax net expenses of $342 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2014 primarily related to the impact of the following:

- $374 million ($248 million after-tax) in charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, attributable to Dominion Generation; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

In 2013, Virginia Power reported after-tax net expenses of $47 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2013 primarily related to the impact of the following:

- A $40 million ($28 million after-tax) charge in connection with the 2013 Biennial Review Order, attributable to Dominion Generation.

The following table presents segment information pertaining to Virginia Power s operations:

Year Ended December 31, (millions)	DVP	Dominion Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2015					
Operating revenue	**$ 2,099**	**$ 5,566**	**$ (43)**	**$**	**$ 7,622**
Depreciation and amortization	**498**	**453**	**2**		**953**
Interest income		**7**			**7**
Interest and related charges	**230**	**210**	**4**	**(1)**	**443**
Income taxes	**308**	**437**	**(86)**		**659**
Net income (loss)	**490**	**750**	**(153)**		**1,087**
Capital expenditures	**1,569**	**1,120**			**2,689**
Total assets (billions)	**14.7**	**17.0**		**(0.1)**	**31.6**
2014					
Operating revenue	$ 1,928	$ 5,651	$	$	$ 7,579
Depreciation and amortization	462	416	37		915
Interest income		8			8
Interest and related charges	205	203	3		411
Income taxes	317	416	(185)		548
Net income (loss)	509	691	(342)		858
Capital expenditures	1,651	1,456			3,107
Total assets (billions)	13.2	16.4		(0.1)	29.5
2013					
Operating revenue	$ 1,826	$ 5,475	$ (6)	$	$ 7,295
Depreciation and amortization	427	425	1		$ 853
Interest income		6			$ 6
Interest and related charges	175	192	2		$ 369
Income taxes	286	399	(26)		$ 659
Net income (loss)	483	702	(47)		$ 1,138
Capital expenditures	1,360	1,173			$ 2,533

DOMINION GAS

The Corporate and Other Segment of Dominion Gas primarily includes specific items attributable to Dominion Gas operating segment that are not included in profit measures evaluated by executive management in assessing the segment s performance and the effect of certain items recorded at Dominion Gas as a result of Dominion s basis in the net assets contributed.

In 2015, Dominion Gas reported after-tax net expenses of $21 million in its Corporate and Other segment, with $13 million of these net expenses attributable to specific items related to its operating segment.

The net expenses for specific items in 2015 primarily related to the impact of the following:

- $16 million ($10 million after-tax) ceiling test impairment charge.

In 2014, Dominion Gas reported after-tax net expenses of $9 million in its Corporate and Other segment, with none of these net expenses attributable to specific items related to its operating segment.

In 2013, Dominion Gas reported after-tax net expenses of $49 million in the Corporate and Other segment, with $41 million of these net expenses attributable to specific items related to its operating segment.

The net expenses for specific items in 2013 primarily related to the impact of the following:

- $55 million ($33 million after-tax) of impairment charges related to certain natural gas infrastructure assets; and
- A $14 million ($8 million after-tax) charge primarily reflecting severance pay and other benefits related to workforce reductions.

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Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion Gas operations:

Year Ended December 31, (millions)	Dominion Energy	Corporate and Other	Consolidated Total
2015			
Operating revenue	**$ 1,716**	**$**	**$ 1,716**
Depreciation and amortization	**213**	**4**	**217**
Equity in earnings of equity method investees	**23**		**23**
Interest income	**1**		**1**
Interest and related charges	**72**	**1**	**73**
Income taxes	**296**	**(13)**	**283**
Net income (loss)	**478**	**(21)**	**457**
Investment in equity method investees	**102**		**102**
Capital expenditures	**795**		**795**
Total assets (billions)	**9.7**	**0.6**	**10.3**
2014			
Operating revenue	$ 1,898	$	$ 1,898
Depreciation and amortization	197		197
Equity in earnings of equity method investees	21		21
Interest income	1		1
Interest and related charges	27		27
Income taxes	340	(6)	334
Net income (loss)	521	(9)	512
Investment in equity method investees	107		107
Capital expenditures	719		719
Total assets (billions)	9.2	0.6	9.8
2013			
Operating revenue	$ 1,937	$	$ 1,937
Depreciation and amortization	188		188
Equity in earnings of equity method investees	22		22
Interest income	2		2
Interest and related charges	28		28
Income taxes	333	(32)	301
Net income (loss)	510	(49)	461
Capital expenditures	650		650

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NOTE 26. QUARTERLY FINANCIAL AND COMMON STOCK DATA (UNAUDITED)

A summary of the Companies quarterly results of operations for the years ended December 31, 2015 and 2014 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.

DOMINION

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2015					
Operating revenue	**$ 3,409**	**$ 2,747**	**$ 2,971**	**$ 2,556**	**$ 11,683**
Income from operations	**1,002**	**773**	**1,123**	**638**	**3,536**
Net income including noncontrolling interests	**540**	**418**	**599**	**366**	**1,923**
Income from continuing operations(1)	**536**	**413**	**593**	**357**	**1,899**
Net income attributable to Dominion	**536**	**413**	**593**	**357**	**1,899**
Basic EPS:					
Income from continuing operations(1)	**0.91**	**0.70**	**1.00**	**0.60**	**3.21**
Net income attributable to Dominion	**0.91**	**0.70**	**1.00**	**0.60**	**3.21**
Diluted EPS:					
Income from continuing operations(1)	**0.91**	**0.70**	**1.00**	**0.60**	**3.20**
Net income attributable to Dominion	**0.91**	**0.70**	**1.00**	**0.60**	**3.20**
Dividends declared per share	**0.6475**	**0.6475**	**0.6475**	**0.6475**	**2.5900**
Common stock prices (intraday high-low)	**$ 79.89 - 68.25**	**$ 74.34 - 66.52**	**$ 76.59 - 66.65**	**$ 74.88 - 64.54**	**$ 79.89 - 64.54**

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2014					
Operating revenue	$ 3,630	$ 2,813	$ 3,050	$ 2,943	$ 12,436
Income from operations	768	394	921	638	2,721
Net income including noncontrolling interests	385	161	531	249	1,326
Income from continuing operations(1)	379	159	529	243	1,310
Net income attributable to Dominion	379	159	529	243	1,310
Basic EPS:					
Income from continuing operations(1)	0.65	0.27	0.91	0.42	2.25
Net income attributable to Dominion	0.65	0.27	0.91	0.42	2.25
Diluted EPS:					
Income from continuing operations(1)	0.65	0.27	0.90	0.42	2.24
Net income attributable to Dominion	0.65	0.27	0.90	0.42	2.24
Dividends declared per share	0.60	0.60	0.60	0.60	2.40
Common stock prices (intraday high-low)	$ 72.22 - 63.14	$ 73.75 - 67.06	$ 71.62 - 64.71	$ 80.89 - 65.53	$ 80.89 - 63.14

(1) Amounts attributable to Dominion s common shareholders.

There were no significant items impacting Dominion s 2015 quarterly results.

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Dominion s 2014 results include the impact of the following significant items:

- Fourth quarter results include $172 million in after-tax charges associated with the Liability Management Exercise in 2014 and $74 million in after-tax costs related to Virginia Power s settlement offer to incur future ash pond closure costs at certain utility generation facilities.
- Second quarter results include $191 million in after-tax charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities.
- First quarter results include a $193 million after-tax reduction in revenues associated with the repositioning of Dominion s producer services business which was completed in the first quarter of 2014.

VIRGINIA POWER

Virginia Power s quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2015					
Operating revenue	**$ 2,137**	**$ 1,813**	**$ 2,058**	**$ 1,614**	**$ 7,622**
Income from operations	**525**	**481**	**741**	**374**	**2,121**
Net income	**269**	**246**	**385**	**187**	**1,087**
Balance available for common stock	**269**	**246**	**385**	**187**	**1,087**
2014					
Operating revenue	$ 1,983	$ 1,729	$ 2,053	$ 1,814	$ 7,579
Income from operations	613	205	594	312	1,724
Net income	324	69	314	151	858
Balance available for common stock	318	67	312	148	845

Virginia Power s 2015 results include the impact of the following significant items:

- Fourth quarter results include a $32 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities.
- Second quarter results include a $28 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities due to the enactment of the final CCR rule in April 2015.
- First quarter results include a $52 million after-tax write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

Virginia Power s 2014 results include the impact of the following significant items:

- Fourth quarter results include $74 million in after-tax costs related to Virginia Power s settlement offer to incur future ash pond closure costs at certain utility generation facilities.
- Second quarter results include a $191 million after-tax charge associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities.

DOMINION GAS

Dominion Gas quarterly results of operations were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year

(millions)					
2015					
Operating revenue	**$ 531**	**$ 395**	**$ 365**	**$ 425**	**$ 1,716**
Income from operations	**271**	**153**	**202**	**163**	**789**
Net income	**161**	**85**	**111**	**100**	**457**
2014					
Operating revenue	$ 569	$ 428	$ 391	$ 510	$ 1,898
Income from operations	265	154	177	255	851
Net income	164	93	107	148	512

Dominion Gas 2015 results include the impact of the following significant items:

- Third quarter results include a $29 million after-tax gain from an agreement to convey shale development rights underneath a natural gas storage field.
- First quarter results include a $43 million after-tax gain from agreements to convey shale development rights underneath several natural gas storage fields.

Dominion Gas 2014 results include the impact of the following significant item:

- Fourth quarter results include a $36 million after-tax gain from agreements to convey Marcellus Shale development rights underneath several natural gas storage fields.

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Combined Notes to Consolidated Financial Statements, Continued

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

None.

Item 9A. Controls and Procedures

DOMINION

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

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion understands and accepts responsibility for Dominion s financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as Dominion does throughout all aspects of its business.

Dominion maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its 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 Dominion s 2015 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 the report, Dominion tested and evaluated the design and operating effectiveness of internal controls. Based on its assessment as of December 31, 2015, Dominion makes the following assertions:

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.

Management evaluated Dominion s internal control over financial reporting as of December 31, 2015. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion maintained effective internal control over financial reporting as of December 31, 2015.

Dominion s independent registered public accounting firm is engaged to express an opinion on Dominion s internal control over financial reporting, as stated in their report which is included herein.

February 26, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Dominion Resources, Inc.

Richmond, Virginia

We have audited the internal control over financial reporting of Dominion Resources, Inc. and subsidiaries (Dominion) as of December 31, 2015, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Dominion 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, included in the accompanying Management s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Dominion 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, Dominion maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* 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, 2015 of Dominion and our report dated February 26, 2016 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Richmond, Virginia

February 26, 2016

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Virginia Power

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

Management s Annual Report On Internal Control Over Financial Reporting

Management of Virginia Power understands and accepts responsibility for Virginia Power s financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Virginia Power continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

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

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

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Virginia Power s 2015 Annual Report to contain a management s report regarding the effectiveness of internal control. As a basis for the report, Virginia Power tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2015, Virginia Power makes the following assertions:

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

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

Management evaluated Virginia Power s internal control over financial reporting as of December 31, 2015. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of

the Treadway Commission. Based on this assessment, management believes that Virginia Power maintained effective internal control over financial reporting as of December 31, 2015.

This annual report does not include an attestation report of Virginia Power s independent registered public accounting firm regarding internal control over financial reporting. Management s report is not subject to attestation by Virginia Power s independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 26, 2016

Dominion Gas

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

Management s Annual Report On Internal Control Over Financial Reporting

Management of Dominion Gas understands and accepts responsibility for Dominion Gas financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Gas continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

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

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

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Dominion Gas 2015 Annual Report to contain a management s report regarding the effectiveness of internal control. As a basis for the report, Dominion Gas tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2015, Dominion Gas makes the following assertions:

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

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.

Management evaluated Dominion Gas internal control over financial reporting as of December 31, 2015. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Gas maintained effective internal control over financial reporting as of December 31, 2015.

This annual report does not include an attestation report of Dominion Gas independent registered public accounting firm regarding internal control over financial reporting. Management s report is not subject to attestation by Dominion Gas independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 26, 2016

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Dominion

The following information for Dominion is incorporated by reference from the Dominion 2016 Proxy Statement, which will be filed on or around March 23, 2016:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding a material change in the procedures by which shareholders recommend director nominees required by this item is found under the headings *Election of Directors* and *Shareholder Proposals and Director Nominations*.
- Information regarding compliance with Section 16 of the Securities Exchange Act of 1934, as amended, required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.
- Information regarding the Dominion Audit Committee Financial expert(s) required by this item is found under the heading *Board of Directors Committees Audit Committee*.
- Information regarding the Dominion Audit Committee required by this item is found under the headings *Board of Directors Committees Audit Committee* and *Audit Committee Report*.
- Information regarding Dominion s Code of Ethics required by this item is found under the heading *Corporate Governance and Board Matters*.

The information concerning the executive officers of Dominion required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of Dominion*. Each executive officer of Dominion is elected annually.

Item 11. Executive Compensation

Dominion

The following information about Dominion is contained in the 2016 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; *The Compensation, Governance and Nominating Committee Report*; and the information regarding director compensation contained under the heading *Compensation of Non-Employee Directors.*

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

Dominion

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Securities Ownership* in the 2016 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion that are authorized for issuance under its equity compensation plans

contained under the heading *Executive Compensation-Equity Compensation Plans* in the 2016 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Dominion

The information regarding related party transactions required by this item found under the heading *Other Information-Related Party Transactions,* and information regarding director independence found under the heading *Corporate Governance and Board Matters Independence of Directors,* in the 2016 Proxy Statement is incorporated by reference.

Item 14. Principal Accountant Fees and Services

Dominion

The information concerning principal accountant fees and services contained under the heading *Auditor Fees and Pre-Approval Policy* in the 2016 Proxy Statement is incorporated by reference.

VIRGINIA POWER AND DOMINION GAS

The following table presents fees paid to Deloitte & Touche LLP for services related to Virginia Power and Dominion Gas for the fiscal years ended December 31, 2015 and 2014.

Type of Fees (millions)	**2015**	2014
Virginia Power		
Audit fees	**$ 1.87**	$ 1.96
Audit-related fees		
Tax fees		
All other fees		
Total Fees	**$ 1.87**	$ 1.96
Dominion Gas		
Audit fees	**$ 1.06**	$ 0.52
Audit-related fees	**0.19**	0.14
Tax fees		
All other fees		
Total Fees	**$ 1.25**	$ 0.66

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

Audit-related fees consist of assurance and related services that are reasonably related to the performance of the audit or review of Virginia Power s and Dominion Gas consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of GAAP to proposed transactions.

Virginia Power s and Dominion Gas Boards of Directors have adopted the Dominion Audit Committee pre-approval policy for their independent auditor s services and fees and have delegated the execution of this policy to the Dominion Audit Committee. In accordance with this delegation, each year the Dominion Audit Committee pre-approves a schedule that details the services to be provided for the following year and an estimated charge for such services. At its January 2016 meeting, the Dominion Audit Committee approved Virginia Power s and Dominion Gas schedules of services and fees for 2016. In accordance with the pre-approval policy, any changes to the pre-approved schedule may be pre-approved by the Dominion Audit Committee or a member of the Dominion Audit Committee.

The fees for Dominion Gas presented above for the year ended December 31, 2014, were for professional services rendered during the period subsequent to Dominion Gas becoming an SEC registrant. Total audit fees and audit-related fees incurred prior to Dominion Gas becoming an SEC registrant were $680 thousand and $70 thousand, respectively, and were paid by Dominion.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

1. Financial Statements

See Index on page 58.

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

3. Exhibits (incorporated by reference unless otherwise noted)

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
2	Purchase and Sale Agreement between Dominion Resources, Inc., Dominion Energy, Inc., Dominion Transmission, Inc. and CONSOL Energy Holdings LLC VI (Exhibit 99.1, Form 8-K filed March 15, 2010, File No. 1-8489).	X		
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of each of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		

4.1.b	See Exhibit 3.1.b above.		X
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Tenth Supplemental Indenture, dated December 1, 2003 (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007 (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255); Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337).			
4.4	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.5	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 $^{7}/8$% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.6	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Fortieth Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 2, 2010, File	X		

No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Eighth Supplemental Indenture, dated March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.7	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (filed herewith).	X		
4.8	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489).	X		
4.9	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 17, 2009 (Exhibit 4.3, Form 8-K filed June 15, 2009, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated July 18, 2014 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489).	X		
4.12	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.14	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as	X		

	Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).		
4.15	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File	X	X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591).			
10.1	$4,000,000,000 Five-Year Amended and Restated Revolving Credit Agreement, dated May 19, 2014, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, The Royal Bank of Scotland plc, Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed May 19, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.2	$500,000,000 Five-Year Amended and Restated Revolving Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Keybank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.1, Form 8-K filed June 2, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.3	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated as of January 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.5	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.6	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission, Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.8	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	
10.10	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	

10.11*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.15*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.16*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.17*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.19*	Dominion Resources, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.20*	Dominion Resources, Inc. Directors Deferred Cash Compensation Plan, as amended and in effect September 20, 2002 (Exhibit 10.4, Form 10-Q for the quarter ended September 30, 2002 filed November 8, 2002, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.3, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.21*	Dominion Resources, Inc. Non-Employee Directors Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.22*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X
10.23*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed	X	X	X

	December 23, 2004, File No. 1-8489).			
10.24*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X
10.25*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.26*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.27*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.28*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.29*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.30*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under 2011 Long-Term Compensation Program approved January 20, 2011 (Exhibit 10.2, Form 8-K filed January 21, 2011, File No. 1-8489).	X	X	X
10.32*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.33*	2012 Performance Grant Plan under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.1, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.34*	Form of Restricted Stock Award Agreement under the 2012 Long-term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489)	X	X	X
10.35*	2013 Performance Grant Plan under 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.36*	Form of Restricted Stock Award Agreement under the 2013 Long-term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489)	X	X	X
10.37*	Restricted Stock Award Agreement for Thomas F. Farrell II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X
10.38*	Retirement Agreement, dated as of June 20, 2013, between Dominion Resources, Inc. and Gary L. Sypolt (Exhibit 10.1, Form 8-K filed June 24, 2013, File No. 1-8489).	X		
10.39*	2014 Performance Grant Plan under 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013, File No. 1-8489).	X	X	X
10.40*	Form of Restricted Stock Award Agreement under the 2014 Long-term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended	X	X	X

December 31, 2013, File No. 1-8489).

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.41*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013, File No. 1-8489).	X	X	X
10.42*	Dominion Resources, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X
10.43	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.44	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X
10.45*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014, File No. 1-8489).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2015 Long-term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014, File No. 1-8489).	X	X	X
10.47*	2016 Performance Grant Plan under 2016 Long-Term Incentive Program approved January 21, 2016 (filed herewith).	X	X	X
10.48*	Form of Restricted Stock Award Agreement under the 2016 Long-term Incentive Program approved January 21, 2016 (filed herewith).	X	X	X
10.49*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.50*	Non-employee directors annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	

31.e	Certification by Chief Executive Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X
31.f	Certification by Chief Financial Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X	

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X
101	The following financial statements from Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2015, filed on February 26, 2016, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement*

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Signatures

Dominion

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

DOMINION RESOURCES, INC.

By: /s/ Thomas F. Farrell II
(Thomas F. Farrell II, Chairman, President and Chief Executive Officer)

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 26th day of February, 2016.

Signature	Title
/s/ Thomas F. Farrell II	Chairman of the Board of Directors, President and Chief
Thomas F. Farrell II	Executive Officer
/s/ William P. Barr	Director
William P. Barr	
/s/ Helen E. Dragas	Director
Helen E. Dragas	
/s/ James O. Ellis, Jr.	Director
James O. Ellis, Jr.	
/s/ John W. Harris	Director
John W. Harris	
/s/ Mark J. Kington	Director
Mark J. Kington	
/s/ Pamela J. Royal	Director

Pamela J. Royal	
/s/ Robert H. Spilman, Jr.	Director
Robert H. Spilman, Jr.	
/s/ Michael E. Szymanczyk	Director
Michael E. Szymanczyk	
/s/ David A. Wollard	Director
David A. Wollard	
/s/ Mark F. McGettrick	Executive Vice President and Chief Financial Officer
Mark F. McGettrick	
/s/ Michele L. Cardiff	Vice President, Controller and Chief Accounting Officer
Michele L. Cardiff	

Virginia Power

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

VIRGINIA ELECTRIC AND POWER COMPANY

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

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 26th day of February, 2016.

Signature	Title
/s/ Thomas F. Farrell II **Thomas F. Farrell II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

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Dominion Gas

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

DOMINION GAS HOLDINGS, LLC

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

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 26th day of February, 2016.

Signature	Title
/s/ Thomas F. Farrell II **Thomas F. Farrell II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

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Exhibit Index

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
2	Purchase and Sale Agreement between Dominion Resources, Inc., Dominion Energy, Inc., Dominion Transmission, Inc. and CONSOL Energy Holdings LLC VI (Exhibit 99.1, Form 8-K filed March 15, 2010, File No. 1-8489).	X		
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of each of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		
4.1.b	See Exhibit 3.1.b above.		X	
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X	
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Tenth Supplemental Indenture, dated December 1, 2003 (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007	X	X	

(Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255); Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337).			
4.4	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.5	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 $^{7}/8$% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.6	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Fortieth Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 2, 2010, File No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Eighth Supplemental Indenture, dated	X		

	March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).	
4.7	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (filed herewith).	X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.8	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489).	X		
4.9	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 17, 2009 (Exhibit 4.3, Form 8-K filed June 15, 2009, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated July 18, 2014 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489).	X		
4.12	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.14	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).	X		
4.15	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of	X		X

October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591).

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.1	$4,000,000,000 Five-Year Amended and Restated Revolving Credit Agreement, dated May 19, 2014, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, The Royal Bank of Scotland plc, Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed May 19, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.2	$500,000,000 Five-Year Amended and Restated Revolving Credit Agreement among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Keybank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.1, Form 8-K filed June 2, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.3	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated as of January 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.5	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.6	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission, Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.8	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	
10.10	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	
10.11*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X

10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.15*	Dominion Resources, Inc. Executives Deferred Compensation Plan, amended and restated effective December 17, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.16*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.17*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.19*	Dominion Resources, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.20*	Dominion Resources, Inc. Directors Deferred Cash Compensation Plan, as amended and in effect September 20, 2002 (Exhibit 10.4, Form 10-Q for the quarter ended September 30, 2002 filed November 8, 2002, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.3, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.21*	Dominion Resources, Inc. Non-Employee Directors Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.22*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X
10.23*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed	X	X	X

	December 23, 2004, File No. 1-8489).			
10.24*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X
10.25*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.26*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.27*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.28*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.29*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.30*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under 2011 Long-Term Compensation Program approved January 20, 2011 (Exhibit 10.2, Form 8-K filed January 21, 2011, File No. 1-8489).	X	X	X
10.32*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.33*	2012 Performance Grant Plan under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.1, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.34*	Form of Restricted Stock Award Agreement under the 2012 Long-term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489)	X	X	X
10.35*	2013 Performance Grant Plan under 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.36*	Form of Restricted Stock Award Agreement under the 2013 Long-term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489)	X	X	X
10.37*	Restricted Stock Award Agreement for Thomas F. Farrell II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X
10.38*	Retirement Agreement, dated as of June 20, 2013, between Dominion Resources, Inc. and Gary L. Sypolt (Exhibit 10.1, Form 8-K filed June 24, 2013, File No. 1-8489).	X		
10.39*	2014 Performance Grant Plan under 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013, File No. 1-8489).	X	X	X
10.40*	Form of Restricted Stock Award Agreement under the 2014 Long-term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended	X	X	X

	December 31, 2013, File No. 1-8489).			
10.41*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013, File No. 1-8489).	X	X	X
10.42*	Dominion Resources, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.43	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.44	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X
10.45*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014, File No. 1-8489).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2015 Long-term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014, File No. 1-8489).	X	X	X
10.47*	2016 Performance Grant Plan under 2016 Long-Term Incentive Program approved January 21, 2016 (filed herewith).	X	X	X
10.48*	Form of Restricted Stock Award Agreement under the 2016 Long-term Incentive Program approved January 21, 2016 (filed herewith).	X	X	X
10.49*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.50*	Non-employee directors annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.e	Certification by Chief Executive Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
31.f	Certification by Chief Financial Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
32.a		X		

	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X

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Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
101	The following financial statements from Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2015, filed on February 26, 2016, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement*