Spectra Energy Corp.
Form 10-Q
August 08, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2011

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-33007

SPECTRA ENERGY CORP

(Exact Name of Registrant as Specified in its Charter)

Delaware	**20-5413139**
(State or other jurisdiction of incorporation)	**(IRS Employer Identification No.)**

5400 Westheimer Court

Houston, Texas 77056

(Address of principal executive offices, including zip code)

713-627-5400

(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 x 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 x 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 Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

Number of shares of Common Stock, $0.001 par value, outstanding as of June 30, 2011: 650,279,848

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SPECTRA ENERGY CORP

FORM 10-Q FOR THE QUARTER ENDED

June 30, 2011

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management s beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;
- the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering, processing and other related infrastructure projects and the effects of competition;
- the performance of natural gas transmission and storage, distribution, and gathering and processing facilities;

- the extent of success in connecting natural gas supplies to gathering, processing and transmission systems and in connecting to expanding gas markets;

- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;

- conditions of the capital markets during the periods covered by these forward-looking statements; and

- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In millions, except per-share amounts)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating Revenues				
Transportation, storage and processing of natural gas	$ 773	$ 696	$ 1,564	$ 1,406
Distribution of natural gas	286	251	893	835
Sales of natural gas liquids	93	70	270	216
Other	36	46	73	86
Total operating revenues	1,188	1,063	2,800	2,543
Operating Expenses				
Natural gas and petroleum products purchased	180	156	665	608
Operating, maintenance and other	347	334	661	636
Depreciation and amortization	177	156	352	317
Property and other taxes	82	75	167	148
Total operating expenses	786	721	1,845	1,709
Gains on Sales of Other Assets and Other, net			4	
Operating Income	402	342	959	834
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	162	77	268	199
Other income and expenses, net	18	6	24	10
Total other income and expenses	180	83	292	209
Interest Expense	159	158	314	317
Earnings From Continuing Operations Before Income Taxes	423	267	937	726
Income Tax Expense From Continuing Operations	125	76	264	173
Income From Continuing Operations	298	191	673	553
Income From Discontinued Operations, net of tax	9		16	16
Net Income	307	191	689	569
Net Income Noncontrolling Interests	23	17	48	37

Net Income Controlling Interests	$ 284	$ 174	$ 641	$ 532
Common Stock Data				
Weighted-average shares outstanding				
Basic	650	648	650	648
Diluted	652	650	652	650
Earnings per share from continuing operations				
Basic and Diluted	$ 0.42	$ 0.27	$ 0.96	$ 0.79
Earnings per share				
Basic	$ 0.44	$ 0.27	$ 0.99	$ 0.82
Diluted	$ 0.44	$ 0.27	$ 0.98	$ 0.82
Dividends per share	$ 0.26	$ 0.25	$ 0.52	$ 0.50

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	$ 538	$ 130
Receivables, net	914	1,018
Inventory	264	287
Other	226	203
Total current assets	1,942	1,638
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,111	2,033
Goodwill	4,421	4,305
Other	523	665
Total investments and other assets	7,055	7,003
Property, Plant and Equipment		
Cost	23,383	22,162
Less accumulated depreciation and amortization	5,582	5,182
Net property, plant and equipment	17,801	16,980
Regulatory Assets and Deferred Debits	1,141	1,065
Total Assets	$ 27,939	$ 26,686

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions, except per-share amounts)

	June 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 592	$ 369
Short-term borrowings and commercial paper	577	836
Taxes accrued	58	59
Interest accrued	181	167
Current maturities of long-term debt	66	315
Other	715	777
Total current liabilities	2,189	2,523
Long-term Debt	10,640	10,169
Deferred Credits and Other Liabilities		
Deferred income taxes	3,885	3,555
Regulatory and other	1,684	1,694
Total deferred credits and other liabilities	5,569	5,249
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	258
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 650 million and 649 million shares outstanding at June 30, 2011 and December 31, 2010, respectively	1	1
Additional paid-in capital	4,791	4,726
Retained earnings	1,787	1,487
Accumulated other comprehensive income	1,867	1,595
Total controlling interests	8,446	7,809
Noncontrolling interests	837	678
Total equity	9,283	8,487
Total Liabilities and Equity	$ 27,939	$ 26,686

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 689	$ 569
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	359	324
Deferred income tax expense	199	30
Equity in earnings of unconsolidated affiliates	(268)	(199)
Distributions received from unconsolidated affiliates	201	237
Other	158	(130)
Net cash provided by operating activities	1,338	831
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(739)	(497)
Investments in and loans to unconsolidated affiliates	(4)	(3)
Purchases of held-to-maturity securities	(763)	(530)
Proceeds from sales and maturities of held-to-maturity securities	733	507
Purchases of available-for-sale securities	(930)	(12)
Proceeds from sales and maturities of available-for-sale securities	1,119	
Distributions received from unconsolidated affiliates		12
Other	13	2
Net cash used in investing activities	(571)	(521)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of long-term debt	2,424	1,440
Payments for the redemption of long-term debt	(2,371)	(1,786)
Net increase (decrease) in short-term borrowings and commercial paper	(258)	334
Distributions to noncontrolling interests	(47)	(36)
Proceeds from the issuance of Spectra Energy Partners, LP common units	213	
Dividends paid on common stock	(341)	(325)
Other	19	5
Net cash used in financing activities	(361)	(368)
Effect of exchange rate changes on cash	2	(2)
Net increase (decrease) in cash and cash equivalents	408	(60)
Cash and cash equivalents at beginning of period	130	166
Cash and cash equivalents at end of period	$ 538	$ 106

Supplemental Disclosures		
Property, plant and equipment accruals	$ 169	$ 102

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(Unaudited)

(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Other	Noncontrolling Interests	Total
December 31, 2010	$ 1	$ 4,726	$ 1,487	$ 2,010	$ (415)	$ 678	$ 8,487
Net income			641			48	689
Foreign currency translation adjustments				244		4	248
Reclassification of cash flow hedges into earnings					5		5
Pension and benefits impact					15		15
Dividends on common stock			(341)				(341)
Stock-based compensation		27					27
Distributions to noncontrolling interests						(47)	(47)
Spectra Energy Partners, LP common unit issuance		38				154	192
Other, net					8		8
June 30, 2011	$ 1	$ 4,791	$ 1,787	$ 2,254	$ (387)	$ 837	$ 9,283
December 31, 2009	$ 1	$ 4,645	$ 1,088	$ 1,682	$ (375)	$ 540	$ 7,581
Net income			532			37	569
Foreign currency translation adjustments				(111)		10	(101)
Unrealized mark-to-market net loss on hedges					(18)		(18)
Reclassification of cash flow hedges into earnings					1		1
Pension and benefits impact					12		12
Dividends on common stock			(325)				(325)
Stock-based compensation		15					15
Distributions to noncontrolling interests						(36)	(36)
Other, net		(22)				1	(21)
June 30, 2010	$ 1	$ 4,638	$ 1,295	$ 1,571	$ (380)	$ 552	$ 7,677

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. General

The terms we, our, us, and Spectra Energy as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy.

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, operating in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. We provide transportation and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. In addition, we own a 50% interest in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States.

Basis of Presentation. The accompanying Condensed Consolidated Financial Statements include our accounts and the accounts of our majority-owned subsidiaries. These interim financial statements should be read in conjunction with the consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2010, and reflect all normal recurring adjustments that are, in our opinion, necessary to fairly present our results of operations and financial position. Amounts reported in the Condensed Consolidated Statements of Operations are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, primarily in our gas distribution operations, as well as changing commodity prices on certain of our processing operations and other factors.

We have corrected certain balances in the accompanying Condensed Consolidated Statements of Equity due to errors identified during 2010 related primarily to the impacts of Canadian federal and provincial tax rate changes on deferred income tax balances associated with our Canadian operations. We have concluded that these corrections are immaterial to our previously issued financial statements.

The corrections related to deferred income tax balances are as follows:

Condensed Consolidated Statement of Equity	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income Foreign Currency Translation Adjustments (in millions)	Accumulated Other Comprehensive Income Other	Total Equity
June 30, 2010					
As previously reported	$ 4,693	$ 1,303	$ 1,575	$ (363)	$ 7,761
Decrease	(55)	(8)	(4)	(17)	(84)
As corrected	$ 4,638	$ 1,295	$ 1,571	$ (380)	$ 7,677

Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, we make estimates and assumptions that affect the amounts reported in the Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements. Although these estimates are based on our best available knowledge at the time, actual results could differ.

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2. Acquisition of Big Sandy Pipeline, LLC (Big Sandy)

On July 1, 2011, Spectra Energy Partners, LP (Spectra Energy Partners) completed the acquisition of Big Sandy from EQT Corporation (EQT) for approximately $390 million in cash. Big Sandy s primary asset is a 68-mile Federal Energy Regulatory Commission (FERC)-regulated natural gas pipeline system in eastern Kentucky. The Big Sandy natural gas pipeline system connects Appalachian and Huron Shale natural gas supplies to markets in the mid-Atlantic and Northeast portions of the United States. The acquisition of Big Sandy strengthens Spectra Energy Partners portfolio of fee-based natural gas assets and is consistent with its strategy of growth through third-party acquisitions.

The assets and liabilities of Big Sandy will be recorded at their respective fair values as of the purchase date and the results of operations will be included in the Condensed Consolidated Financial Statements beginning as of the effective date of the acquisition. Big Sandy will be part of the U.S. Transmission segment. Given the recent closing of the transaction, the initial accounting and supplemental pro forma information for the transaction is not available.

3. Business Segments

We manage our business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of our business operations is presented as Other, and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities, and other miscellaneous activities.

Our chief operating decision maker regularly reviews financial information about each of these segments in deciding how to allocate resources and evaluate performance. There is no aggregation within our defined business segments.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the rules and regulations of the FERC. Spectra Energy Partners, a master limited partnership, is part of the U.S. Transmission segment.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants. These services are provided by Union Gas Limited (Union Gas), and are primarily subject to the rules and regulations of the Ontario Energy Board (OEB).

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and natural gas liquids (NGLs) extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern tier of the United States. This segment conducts business mostly through BC Pipeline, BC Field Services, and the NGL marketing and Canadian Midstream businesses. BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada s National Energy Board (NEB).

Field Services gathers and processes natural gas and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by ConocoPhillips. DCP Midstream gathers raw natural gas through gathering systems located in nine major conventional and non-conventional natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream has a 27% ownership interest in DCP Midstream Partners, LP (DCP Partners), a master limited partnership.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT) from continuing operations less noncontrolling interests related to those earnings.

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On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and short-term investments are managed centrally, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments EBIT. Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Operating Revenues (a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes (a)
		(in millions)		
Three Months Ended June 30, 2011				
U.S. Transmission	$ 454	$ 3	$ 457	$ 243
Distribution	375		375	88
Western Canada Transmission & Processing	357	14	371	113
Field Services				138
Total reportable segments	1,186	17	1,203	582
Other	2	14	16	(29)
Eliminations		(31)	(31)	
Interest expense				159
Interest income and other (b)				29
Total consolidated	$ 1,188	$	$ 1,188	$ 423
Three Months Ended June 30, 2010				
U.S. Transmission	$ 440	$ 2	$ 442	$ 223
Distribution	331		331	73
Western Canada Transmission & Processing	289		289	69
Field Services				58
Total reportable segments	1,060	2	1,062	423
Other	3	11	14	(16)
Eliminations		(13)	(13)	
Interest expense				158
Interest income and other (b)				18
Total consolidated	$ 1,063	$	$ 1,063	$ 267
Six Months Ended June 30, 2011				
U.S. Transmission	$ 935	$ 5	$ 940	$ 522
Distribution	1,071		1,071	255
Western Canada Transmission & Processing	790	20	810	254
Field Services				219
Total reportable segments	2,796	25	2,821	1,250
Other	4	29	33	(53)
Eliminations		(54)	(54)	
Interest expense				314
Interest income and other (b)				54
Total consolidated	$ 2,800	$	$ 2,800	$ 937
Six Months Ended June 30, 2010				
U.S. Transmission	$ 896	$ 3	$ 899	$ 470
Distribution	999		999	219

Western Canada Transmission & Processing		644			644		188
Field Services							157
Total reportable segments		2,539	3		2,542		1,034
Other		4	23		27		(30)
Eliminations			(26)		(26)		
Interest expense							317
Interest income and other (b)							39
Total consolidated	$	2,543	$	$	2,543	$	726

(a) Excludes amounts associated with entities included in discontinued operations.
(b) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.

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4. Regulatory Matters

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). M&N LP filed an application with the NEB in July 2010 seeking compensation for funds held in escrow. In June 2011, the NEB denied M&N LP s application and finalized tolls for 2010, with the tolls equal to the 2010 interim tolls previously approved. The NEB s decision did not have any effect on our consolidated results of operations, financial position or cash flows.

Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission). In 2010, FERC initiated a rate proceeding that required Ozark to file a Cost and Revenue Study by February 1, 2011. A settlement agreement was reached with parties involved in the proceeding and filed with the FERC on April 29, 2011. A final FERC order on the settlement agreement is expected in the third quarter of 2011. Management believes that the effects of this matter will not have a material adverse effect on our future consolidated results of operations, financial position or cash flows.

5. Income Taxes

Income tax expense from continuing operations for the three months ended June 30, 2011 was $125 million, compared to $76 million for the same period in 2010, increasing primarily as a result of higher earnings from continuing operations. Income tax expense from continuing operations for the six months ended June 30, 2011 was $264 million, compared to $173 million reported for the same period in 2010. The higher income tax expense resulted from higher earnings from continuing operations in the second quarter of 2011 and favorable tax audit settlements totaling $24 million in the first quarter of 2010.

The effective tax rates for income from continuing operations for the three-month periods ended June 30, 2011 and June 30, 2010 were 29.6% and 28.5%, respectively, and 28.2% and 23.8% for six-month periods. The higher effective tax rates in 2011 include an increase in state tax rates. Favorable tax audit settlements in the first quarter of 2010 also contributed to the lower rate in the 2010 six-month period. The favorable tax audit settlements were related mainly to an administrative change by the Canadian federal government that resulted in tax refunds from historical tax years and a reduction to the deferred tax liability.

No material net change in uncertain tax benefits was recognized during the six months ended June 30, 2011. Although uncertain, we believe it is reasonably possible that prior to June 30, 2012 the total amount of unrecognized tax benefits could decrease by approximately $20 million, related to the expiration of statutes of limitations.

6. Discontinued Operations

Discontinued operations is mostly comprised of the net effects of a settlement arrangement related to prior liquefied natural gas contracts and an immaterial positive income tax adjustment in the first quarter of 2010 related to previously discontinued operations.

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The following table summarizes results classified as Income From Discontinued Operations, Net of Tax in the accompanying Condensed Consolidated Statements of Operations:

	Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income (Loss) From Discontinued Operations, Net of Tax
			(in millions)	
Three Months Ended June 30, 2011				
Other	$ 48	$ 15	$ 6	$ 9
Total consolidated	$ 48	$ 15	$ 6	$ 9
Three Months Ended June 30, 2010				
Other	$ 16	$ (1)	$ (1)	$
Total consolidated	$ 16	$ (1)	$ (1)	$
Six Months Ended June 30, 2011				
Other	$ 132	$ 25	9	$ 16
Total consolidated	$ 132	$ 25	$ 9	$ 16
Six Months Ended June 30, 2010				
Other	$ 107	$ 4	$ (12)	$ 16
Total consolidated	$ 107	$ 4	$ (12)	$ 16

7. Comprehensive Income

Components of comprehensive income are as follows:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
		(in millions)		
Net income	$ 307	$ 191	$ 689	$ 569
Other comprehensive income				
Foreign currency translation adjustments	57	(314)	248	(101)
Unrealized mark-to-market net loss on hedges	(1)	(4)		(18)
Reclassification of cash flow hedges into earnings	2	1	5	1
Pension and benefits impact	7	6	15	12
Other			8	
Total comprehensive income (loss), net of tax	372	(120)	965	463
Less: comprehensive income noncontrolling interests	24	13	52	47
Comprehensive income (loss) controlling interests	$ 348	$ (133)	$ 913	$ 416

8. Earnings per Common Share

Basic earnings per common share (EPS) is computed by dividing net income from controlling interests by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income from controlling interests by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards and phantom stock awards, were exercised, settled or converted into common stock.

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The following table presents basic and diluted EPS calculations:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions, except per-share amounts)			
Income from continuing operations, net of tax controlling interests	$ 275	$ 174	$ 625	$ 516
Income from discontinued operations, net of tax controlling interests	9		16	16
Net income controlling interests	$ 284	$ 174	$ 641	$ 532
Weighted-average common shares, outstanding				
Basic	650	648	650	648
Diluted	652	650	652	650
Basic earnings per common share (a)				
Continuing operations	$ 0.42	$ 0.27	$ 0.96	$ 0.79
Discontinued operations, net of tax	0.02		0.03	0.03
Total basic earnings per common share	$ 0.44	$ 0.27	$ 0.99	$ 0.82
Diluted earnings per common share (a)				
Continuing operations	$ 0.42	$ 0.27	$ 0.96	$ 0.79
Discontinued operations, net of tax	0.02		0.02	0.03
Total diluted earnings per common share	$ 0.44	$ 0.27	$ 0.98	$ 0.82

(a) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding.

Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately five million and 10 million shares for the six months ended June 30, 2011 and 2010, respectively, were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the common shares during these periods or performance measures related to the awards had not yet been met.

9. Inventory

Inventory consists of natural gas and NGLs held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories primarily relate to the Distribution segment in Canada and are valued at costs approved by the OEB. The difference between the approved price and the actual cost of gas purchased is recorded in either accounts receivable or other current liabilities, as appropriate, for future disposition with customers, subject to approval by the OEB. The remaining inventory is recorded at cost, primarily using average cost. The components of inventory are as follows:

	June 30, 2011	December 31, 2010
	(in millions)	
Natural gas	$ 136	$ 175
NGLs	53	41
Materials and supplies	75	71
Total inventory	$ 264	$ 287

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10. Investments in and Loans to Unconsolidated Affiliates

Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream, which is accounted for under the equity method of accounting. The following represents summary financial information for DCP Midstream, presented at 100%:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Operating revenues	$ 3,304	$ 2,479	$ 6,233	$ 5,594
Operating expenses	2,957	2,286	5,712	5,128
Operating income	347	193	521	466
Net income	303	131	428	327
Net income attributable to members interests	277	114	410	295

DCP Midstream recorded gains on sales of common units of DCP Partners to equity in the first quarters of 2011 and 2010. Our proportionate 50% share, totaling $14 million and $9 million, respectively, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Condensed Consolidated Statements of Operations.

Related Party Transactions. In 2008, we entered into a settlement agreement related to certain liquefied natural gas transportation contracts under which one of our subsidiaries claims were satisfied pursuant to commercial transactions involving the purchase of propane from certain parties. We subsequently entered into associated agreements with affiliates of DCP Midstream for the sale of these propane volumes. Net purchases and sales of propane under these arrangements are reflected as discontinued operations.

Sales of propane to affiliates of DCP Midstream are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Sales of propane	$ 48	$ 2	$ 132	$ 65

11. Goodwill

We completed our annual goodwill impairment test as of April 1, 2011 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

12. Marketable Securities and Restricted Funds

Available-for-Sale Marketable Securities (AFS Securities). During 2010, we invested a portion of the proceeds from Spectra Energy Partners issuance of common units to the public in AFS securities, which include investments in money market funds and commercial paper. These investments, which totaled $209 million as of December 31, 2010, were pledged as collateral against Spectra Energy Partners term loan and were classified as Investments and Other Assets Other on the Condensed Consolidated Balance Sheet. In addition to these restricted funds, we had $15 million of other restricted AFS securities as of June 30, 2011, classified as Current Assets Other, and $4 million of restricted AFS securities as of June 30, 2011 and $2 million as of December 31, 2010, classified as Investments and Other Assets Other. These other restricted funds are related to insurance.

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In June 2011, Spectra Energy Partners term loan was repaid using proceeds from the issuance of Spectra Energy Partners senior notes. The related investments were subsequently liquidated to fund a portion of Big Sandy. The funds are included in Cash and Cash Equivalents on the Condensed Consolidated Balance Sheet at June 30, 2011.

AFS securities are valued at fair value on the Condensed Consolidated Balance Sheet. Purchases and sales of AFS securities are presented on a gross basis within Cash Flows from Investing Activities on the Condensed Consolidated Statements of Cash Flows.

There were no gross unrealized holding gains or losses associated with investments in AFS securities at June 30, 2011 or December 31, 2010. Estimated fair values of AFS securities follow:

	Estimated Fair Value	
	June 30, 2011	December 31, 2010
	(in millions)	
Corporate debt securities	$ 18	$ 222
Canadian government securities	15	
Money market funds	4	2
Total available-for-sale investments	$ 37	$ 224

Held-to-Maturity Marketable Securities (HTM Securities). HTM securities, totaling $219 million as of June 30, 2011 and $182 million as of December 31, 2010, are classified as Investments and Other Assets Other. These securities, consisting of Canadian government securities, are restricted funds pursuant to certain M&N LP debt agreements. These funds, plus future cash from operations that would otherwise be available for distribution to the partners of M&N LP, are placed in escrow until the balance in escrow is sufficient to fund all future debt service on the notes. The notes payable, totaling $229 million as of June 30, 2011 and $234 million as of December 31, 2010, have semi-annual interest and principal payments and are due in 2019.

HTM securities are valued at cost on the Condensed Consolidated Balance Sheet. Purchases and sales of HTM securities are presented on a gross basis within Cash Flows from Investing Activities. At June 30, 2011, the contractual maturities of outstanding HTM securities are less than one year.

There were no gross unrecognized holding gains or losses associated with investments in HTM securities at June 30, 2011 or December 31, 2010. Estimated fair values of HTM securities follow:

	Estimated Fair Value	
	June 30, 2011	December 31, 2010
	(in millions)	
Canadian government securities	$ 219	$ 182
Total held-to-maturity investments	$ 219	$ 182

Other Restricted Funds. In addition to the restricted AFS and HTM securities described above, we had restricted funds totaling $36 million at June 30, 2011 and $44 million at December 31, 2010 classified as Current Assets Other, and $3 million at June 30, 2011 and $5 million at December 31, 2010 classified as Investments and Other Assets Other. These restricted funds are related to additional amounts for the M&N LP debt service requirements.

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13. Debt and Credit Facilities

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Outstanding at June 30, 2011 Commercial Paper	Revolving Credit (in millions)	Letters of Credit	Total	Available Credit Facilities Capacity
Spectra Energy Capital, LLC (a)							
Multi-year syndicated	2012	$ 1,500	$ 546	$	$ 13	$ 559	$ 941
Westcoast Energy Inc. (b)							
Multi-year syndicated	2015	311					311
Union Gas (c)							
Multi-year syndicated	2012	519	31			31	488
Spectra Energy Partners (d)							
Multi-year syndicated	2012	500		40		40	460
Total		$ 2,830	$ 577	$ 40	$ 13	$ 630	$ 2,200

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%. The ratio was 54% at June 30, 2011.

(b) U.S. dollar equivalent at June 30, 2011. The credit facility totals 300 million Canadian dollars and contains a covenant that requires the Westcoast Energy Inc. non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 40% at June 30, 2011.

(c) U.S. dollar equivalent at June 30, 2011. The credit facility totals 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 60% at June 30, 2011.

(d) Credit facility contains a covenant that requires Spectra Energy Partners to maintain ratios of total Debt-to-Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), as defined in the credit agreement, of 5.0 or less and Adjusted EBITDA-to-interest expense of 2.5 or greater. As of June 30, 2011, these ratios were 3.0 and 13.6, respectively. Adjusted EBITDA is a non-GAAP measure. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by companies in our industry, Spectra Energy Partners definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP.

The issuances of commercial paper, letters of credit and other borrowings reduce the amounts available under the credit facilities.

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of June 30, 2011, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

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Debt Issuances

On June 9, 2011, Spectra Energy Partners issued $500 million aggregate principal amount of unsecured senior notes, including $250 million of 2.95% senior notes due in 2016 and $250 million of 4.60% senior notes due in 2021. Net proceeds from the offering were used to repay all of the outstanding borrowings under Spectra Energy Partners term loan and a significant portion of the funds borrowed under its credit facility. The remaining balance of the proceeds was used for general corporate purposes.

On June 21, 2011, Union Gas issued 300 million Canadian dollars (approximately $309 million) of 4.88% notes due in 2041. Net proceeds from the offering were used for general corporate purposes, including refinancing of prior maturities of debt.

14. Fair Value Measurements

The following table presents, for each of the fair value hierarchy levels, assets and liabilities that are measured and recorded at fair value on a recurring basis:

		June 30, 2011			
Description	**Condensed Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$ 29	$	$ 29	$
Money market funds	Cash and cash equivalents	48	48		
Canadian government securities	Current assets other	15	15		
Corporate debt securities	Investments and other assets other	18		18	
Derivative assets interest rate swaps	Investments and other assets other	52		52	
Money market funds	Investments and other assets other	4	4		
Total Assets		$166	$ 67	$ 99	$
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	$ 8	$	$	$ 8
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	19		19	
Total Liabilities		$ 27	$	$ 19	$ 8

		December 31, 2010			
Description	**Condensed Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$ 74	$	$ 74	$
Corporate debt securities	Investments and other assets other	222		222	
Derivative assets interest rate swaps	Investments and other assets other	48		48	
Money market funds	Investments and other assets other	25	25		
Total Assets		$ 369	$ 25	$ 344	$
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	$ 6	$	$	$ 6
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	20		20	
Total Liabilities		$ 26	$	$ 20	$ 6

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The following table presents changes in Level 3 assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Long-term derivative assets (liabilities)				
Fair value, beginning of period	$ (6)	$	$ (6)	$ 15
Total realized/unrealized gains (losses):				
Included in earnings		(3)	(1)	(3)
Included in other comprehensive income	(2)	4	(1)	(11)
Fair value, end of period	$ (8)	$ 1	$ (8)	$ 1
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets/liabilities held at the end of the period	$ (2)	$ (2)	$ (5)	$ (2)

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of our financial instruments that are actively traded in the secondary market, primarily corporate debt securities, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

For interest rate swaps, we utilize data obtained from multiple sources for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value. In addition, credit default swap rates are used to develop the adjustment for credit risk embedded in our positions. We believe that since some of the inputs and assumptions for the calculations of fair value are derived from observable market data, a Level 2 classification is appropriate.

Level 3 Valuation Techniques

We do not have significant amounts of assets or liabilities measured and reported using Level 3 valuation techniques, which include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

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Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts we could have realized in current markets.

	June 30, 2011		December 31, 2010	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
		(in millions)		
Notes receivable, current (a)	$ 53	$ 54	$ 50	$ 51
Notes receivable, noncurrent (b)	71	71	71	71
Long-term debt, including current maturities	10,706	12,100	10,484	11,874

(a) Included within Receivables, Net on the Condensed Consolidated Balance Sheets.
(b) Included within Investments and Other Assets Other on the Condensed Consolidated Balance Sheets.

The book value and fair value of long-term debt include the impacts of certain pay floating receive fixed interest rate swaps that are designated as fair value hedges.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, accounts payable, short-term borrowings and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

During the 2011 and 2010 periods, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

15. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our Empress operations in Canada. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of forward physical transactions as well as other derivatives, primarily around interest rate exposures.

At June 30, 2011, we had pay floating receive fixed interest rate swaps outstanding with a total notional principal amount of $1,609 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt securities into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. At Spectra Energy Partners, we had third-party pay fixed receive floating interest rate swaps outstanding with a total notional principal amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under its revolving credit facility.

Our equity investment affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Other than interest rate swaps described above, we did not have any significant derivatives outstanding during the six months ended June 30, 2011.

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16. Commitments and Contingencies

Environmental

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian federal and provincial laws, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These laws and regulations can change from time to time, imposing new obligations on us.

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant international, federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliated operations.

Included in Deferred Credits and Other Liabilities Regulatory and Other on the Condensed Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $13 million at June 30, 2011 and $14 million as of December 31, 2010. These accruals represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Litigation and Legal Proceedings. We are involved in legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract and payment claims, some of which may involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of June 30, 2011 or December 31, 2010 related to litigation.

Other Commitments and Contingencies

See Note 17 for a discussion of guarantees and indemnifications.

17. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Condensed Consolidated Balance Sheets. The possibility of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. In connection with our spin-off from Duke Energy Corporation (Duke Energy) in 2007, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of June 30, 2011 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of these performance guarantees, which has a maximum potential amount of future payment of $201 million, expires in 2028. The remaining guarantees have no contractual expirations.

We have also issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments in place at the time of our spin-off from Duke Energy. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners.

Westcoast Energy Inc. (Westcoast), a wholly owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of unconsolidated entities and third-party entities as of June 30, 2011 was $40 million. Of these guarantees, $5 million expire in 2015 and the remaining have no contractual expirations.

We have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time depending on the nature of the claim. Our potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. We are unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

As of June 30, 2011, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

18. Sale of Spectra Energy Partners Units

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $218 million (net proceeds to Spectra Energy were $213 million), used to fund a portion of the acquisition of Big Sandy. See Note 2 for additional information on the acquisition of Big Sandy. The sale of the units decreased Spectra Energy s ownership in Spectra Energy Partners from 69% to 64%. In connection with the sale of the units, a $60 million gain ($38 million net of tax) to Additional Paid-in Capital and a $154 million increase in Equity Noncontrolling Interests were recorded in the second quarter of 2011.

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The following table presents the effects of changes in our ownership interests in non-wholly owned consolidated subsidiaries:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
Net Income Controlling Interests	$ 284	$ 174	$ 641	$ 532
Increase in Additional Paid-in Capital resulting from the sale of units of Spectra Energy Partners	38		38	
Total Net Income Controlling Interests and changes in Equity Controlling Interests	$ 322	$ 174	$ 679	$ 532

19. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and non-qualified plans for various executive retirement and savings plans. Our Westcoast subsidiary maintains qualified and non-qualified contributory and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our Canadian operations.

Our policy is to fund our retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made contributions of $10 million to our U.S. retirement plans in the six-month period ended June 30, 2011 and $5 million for the same period in 2010. We made total contributions to the Canadian DC and qualified DB plans of $36 million during the six-month period ended June 30, 2011 and $34 million during the same period in 2010. We anticipate that we will make total contributions of approximately $20 million to the U.S. plans and approximately $75 million to the Canadian plans in 2011.

Qualified Pension Plans Components of Net Periodic Pension Cost

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
U.S.				
Service cost benefit earned	$ 4	$ 3	$ 7	$ 6
Interest cost on projected benefit obligation	6	7	12	13
Expected return on plan assets	(8)	(8)	(16)	(16)
Amortization of loss	2	2	5	4
Net periodic pension cost	$ 4	$ 4	$ 8	$ 7
Canada				
Service cost benefit earned	$ 5	$ 4	$ 10	$ 8
Interest cost on projected benefit obligation	12	12	24	23
Expected return on plan assets	(13)	(12)	(25)	(23)
Amortization of loss	7	4	13	8
Amortization of prior service costs	1		1	1
Net periodic pension cost	$ 12	$ 8	$ 23	$ 17

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Non-Qualified Pension Benefits Plans Components of Net Periodic Pension Cost

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
U.S.				
Interest cost on projected benefit obligation	$ 1	$ 1	$ 1	$ 1
Net periodic pension cost	$ 1	$ 1	$ 1	$ 1
Canada				
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	3	3
Amortization of actuarial loss	1		1	
Net periodic pension cost	$ 3	$ 2	$ 5	$ 4

Other Post-Retirement Benefit Plans. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in millions)			
U.S.				
Interest cost on accumulated post-retirement benefit obligation	$ 2	$ 3	$ 5	$ 6
Expected return on plan assets	(1)	(2)	(2)	(3)
Amortization of net transition liability		1		2
Amortization of loss	1	1	1	1
Net periodic other post-retirement benefit cost	$ 2	$ 3	$ 4	$ 6
Canada				
Service cost benefit earned	$ 1	$ 1	$ 2	$ 2
Interest cost on accumulated post-retirement benefit obligation	2	2	4	3
Net periodic other post-retirement benefit cost	$ 3	$ 3	$ 6	$ 5

20. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Energy Capital, LLC (Spectra Capital), a wholly owned, consolidated subsidiary. In accordance with Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all wholly owned subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying Condensed Consolidated Financial Statements and notes thereto.

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,188	$	$ 1,188
Total operating expenses	(3)		789		786
Operating income	3		399		402
Equity in earnings of unconsolidated affiliates			162		162
Equity in earnings of subsidiaries	282	425		(707)	
Other income and expenses, net		6	12		18
Interest expense		51	108		159
Earnings from continuing operations before income taxes	285	380	465	(707)	423
Income tax expense from continuing operations	1	98	26		125
Income from continuing operations	284	282	439	(707)	298
Income from discontinued operations, net of tax			9		9
Net income	284	282	448	(707)	307
Net income noncontrolling interests			23		23
Net income controlling interests	$ 284	$ 282	$ 425	$ (707)	$ 284

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,063	$	$ 1,063
Total operating expenses	2	1	718		721
Operating income (loss)	(2)	(1)	345		342
Equity in earnings of unconsolidated affiliates			77		77
Equity in earnings of subsidiaries	175	281		(456)	
Other income and expenses, net			6		6
Interest expense		52	106		158
Earnings before income taxes	173	228	322	(456)	267
Income tax expense (benefit)	(1)	53	24		76
Net income	174	175	298	(456)	191
Net income noncontrolling interests			17		17
Net income controlling interests	$ 174	$ 175	$ 281	$ (456)	$ 174

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 2,800	$	$ 2,800
Total operating expenses			1,845		1,845
Gains on sales of other assets and other, net			4		4
Operating income			959		959
Equity in earnings of unconsolidated affiliates			268		268
Equity in earnings of subsidiaries	641	935		(1,576)	
Other income and expenses, net		6	18		24
Interest expense		99	215		314
Earnings from continuing operations before income taxes	641	842	1,030	(1,576)	937
Income tax expense from continuing operations		201	63		264
Income from continuing operations	641	641	967	(1,576)	673
Income from discontinued operations, net of tax			16		16
Net income	641	641	983	(1,576)	689
Net income noncontrolling interests			48		48
Net income controlling interests	$ 641	$ 641	$ 935	$ (1,576)	$ 641

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 2,543	$	$ 2,543
Total operating expenses	5	1	1,703		1,709
Operating income (loss)	(5)	(1)	840		834
Equity in earnings of unconsolidated affiliates			199		199
Equity in earnings of subsidiaries	535	782		(1,317)	
Other income and expenses, net		2	8		10
Interest expense		102	215		317
Earnings from continuing operations before income taxes	530	681	832	(1,317)	726
Income tax expense (benefit) from continuing operations	(2)	146	29		173
Income from continuing operations	532	535	803	(1,317)	553
Income from discontinued operations, net of tax			16		16
Net income	532	535	819	(1,317)	569
Net income noncontrolling interests			37		37
Net income controlling interests	$ 532	$ 535	$ 782	$ (1,317)	$ 532

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

June 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 1	$ 537	$	$ 538
Receivables (payables) consolidated subsidiaries	3	(1)	(2)		
Receivables other			914		914
Other current assets	62	13	415		490
Total current assets	65	13	1,864		1,942
Investments in and loans to unconsolidated affiliates		70	2,041		2,111
Investments in consolidated subsidiaries	11,749	14,939		(26,688)	
Advances receivable (payable) consolidated subsidiaries	(3,231)	3,827	(36)	(560)	
Goodwill			4,421		4,421
Other assets	43	92	388		523
Property, plant and equipment, net			17,801		17,801
Regulatory assets and deferred debits	1	8	1,132		1,141
Total Assets	$ 8,627	$ 18,949	$ 27,611	$ (27,248)	$ 27,939
Accounts payable other	$ 1	$ 117	$ 474	$	$ 592
Short-term borrowings and commercial paper		1,106	31	(560)	577
Accrued taxes payable (receivable)	(17)	7	68		58
Current maturities of long-term debt		8	58		66
Other current liabilities	49	90	757		896
Total current liabilities	33	1,328	1,388	(560)	2,189
Long-term debt		3,298	7,342		10,640
Deferred credits and other liabilities	148	2,574	2,847		5,569
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	8,446	11,749	14,939	(26,688)	8,446
Noncontrolling interests			837		837
Total equity	8,446	11,749	15,776	(26,688)	9,283
Total Liabilities and Equity	$ 8,627	$ 18,949	$ 27,611	$ (27,248)	$ 27,939

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$	$ 130	$	$ 130
Receivables (payables) consolidated subsidiaries	(46)	208	(162)		
Receivables (payables) other	(4)	1	1,021		1,018
Other current assets	63	37	390		490
Total current assets	13	246	1,379		1,638
Investments in and loans to unconsolidated affiliates		74	1,959		2,033
Investments in consolidated subsidiaries	10,683	13,979		(24,662)	
Advances receivable (payable) consolidated subsidiaries	(2,835)	3,463	(57)	(571)	
Goodwill			4,305		4,305
Other assets	43	45	577		665
Property, plant and equipment, net			16,980		16,980
Regulatory assets and deferred debits		13	1,052		1,065
Total Assets	$ 7,904	$ 17,820	$ 26,195	$ (25,233)	$ 26,686
Accounts payable other	$ 1	$ 76	$ 292	$	$ 369
Short-term borrowings and commercial paper		1,250	157	(571)	836
Accrued taxes payable (receivable)	(145)	99	105		59
Current maturities of long-term debt		8	307		315
Other current liabilities	76	67	801		944
Total current liabilities	(68)	1,500	1,662	(571)	2,523
Long-term debt		3,302	6,867		10,169
Deferred credits and other liabilities	163	2,335	2,751		5,249
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	7,809	10,683	13,979	(24,662)	7,809
Noncontrolling interests			678		678
Total equity	7,809	10,683	14,657	(24,662)	8,487
Total Liabilities and Equity	$ 7,904	$ 17,820	$ 26,195	$ (25,233)	$ 26,686

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Six Months Ended June 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 641	$ 641	$ 983	$ (1,576)	$ 689
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			359		359
Equity in earnings of unconsolidated affiliates			(268)		(268)
Equity in earnings of subsidiaries	(641)	(935)		1,576	
Distributions received from unconsolidated affiliates			201		201
Other	(37)	254	140		357
Net cash provided by (used in) operating activities	(37)	(40)	1,415		1,338
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(739)		(739)
Investments in and loans to unconsolidated affiliates			(4)		(4)
Purchases of held-to-maturity securities			(763)		(763)
Proceeds from sales and maturities of held-to-maturity securities			733		733
Purchases of available-for-sale securities			(930)		(930)
Proceeds from sales and maturities of available-for-sale securities			1,119		1,119
Other			13		13
Net cash used in investing activities			(571)		(571)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			2,424		2,424
Payments for the redemption of long-term debt			(2,371)		(2,371)
Net decrease in short-term borrowings and commercial paper		(132)	(126)		(258)
Distributions to noncontrolling interests			(47)		(47)
Proceeds from the issuance of Spectra Energy Partners common units			213		213
Dividends paid on common stock	(341)				(341)
Distributions and advances from (to) affiliates	353	173	(526)		
Other	25		(6)		19
Net cash provided by (used in) financing activities	37	41	(439)		(361)
Effect of exchange rate changes on cash			2		2

Net increase in cash and cash equivalents		1	407		408
Cash and cash equivalents at beginning of period			130		130
Cash and cash equivalents at end of period	$	$ 1	$ 537	$	$ 538

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Six Months Ended June 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 532	$ 535	$ 819	$ (1,317)	$ 569
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			324		324
Equity in earnings of unconsolidated affiliates			(199)		(199)
Equity in earnings of subsidiaries	(535)	(782)		1,317	
Distributions received from unconsolidated affiliates			237		237
Other	(159)	159	(100)		(100)
Net cash provided by (used in) operating activities	(162)	(88)	1,081		831
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(497)		(497)
Investments in and loans to unconsolidated affiliates			(3)		(3)
Purchases of held-to-maturity securities			(530)		(530)
Proceeds from sales and maturities of held-to-maturity securities			507		507
Purchases of available-for-sale securities			(12)		(12)
Distributions received from unconsolidated affiliates			12		12
Other			2		2
Net cash used in investing activities			(521)		(521)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			1,440		1,440
Payments for the redemption of long-term debt			(1,786)		(1,786)
Net increase in short-term borrowings and commercial paper		149	185		334
Distributions to noncontrolling interests			(36)		(36)
Dividends paid on common stock	(325)	(3)		3	(325)
Distributions and advances from (to) affiliates	486	(51)	(432)	(3)	
Other	1		4		5
Net cash provided by (used in) financing activities	162	95	(625)		(368)
Effect of exchange rate changes on cash			(2)		(2)
Net increase (decrease) in cash and cash equivalents		7	(67)		(60)
Cash and cash equivalents at beginning of period			166		166

Cash and cash equivalents at end of period	$		$	7	$	99	$	$	106

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21. New Accounting Pronouncements

There were no significant accounting pronouncements adopted during the six months ended June 30, 2011 that had a material impact on our consolidated results of operations, financial position or cash flows.

22. Subsequent Events

On July 1, 2011, Spectra Energy Partners completed the acquisition of Big Sandy from EQT. See Note 2 for additional information.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.
INTRODUCTION

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the accompanying Condensed Consolidated Financial Statements.

Executive Overview

During the first half of 2011, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing generated increased earnings and cash flows by meeting the needs of our customers and from successful expansion projects previously placed in service. In addition, commodity prices have improved significantly compared to the same period in 2010 and have positively impacted our earnings in the first half of 2011.

Effective the first quarter of 2011, the quarterly dividend was increased from $0.25 per share to $0.26 per share, representing a 4% increase from the previous dividend level. We continue to anticipate our dividend payout ratio over time to be consistent with our targeted payout ratio, which is up to 65% of estimated annual net income from controlling interests per share of common stock.

For the three months ended June 30, 2011 and 2010, we reported net income from controlling interests of $284 million and $174 million, respectively. For the six months ended June 30, 2011 and 2010, we reported net income from controlling interests of $641 million and $532 million, respectively. Earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, the positive impact of commodity prices on earnings from Field Services, a stronger Canadian dollar and colder weather at Distribution were slightly offset by higher corporate costs.

The highlights for the three and six months ended June 30, 2011 include:

- U.S. Transmission s earnings benefited from the successful execution of planned expansion projects,

- Distribution s earnings increased mainly as a result of higher customer usage of natural gas due to colder weather and a stronger Canadian dollar,

- Western Canada Transmission & Processing earnings increased mainly as a result of higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due primarily to a scheduled plant turnaround in 2010 and a stronger Canadian dollar, and

- Field Services earnings increased as a result of higher commodity prices and lower interest expense, partially offset by higher planned operating expenses and the negative effects of severe weather.

In the first six months of 2011, we had $743 million of capital and investment expenditures. Excluding the acquisition of Big Sandy, we continue to project approximately $2.1 billion of capital and investment expenditures for the full year, including expansion capital of approximately $1.3 billion. 2011 expansion projects are on track and we expect that our capital spending will be significantly higher throughout the remainder of the year.

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As of June 30, 2011, we have access to approximately $2.2 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to complement our ongoing cash flows to fund liquidity needs through the remainder of 2011. Financing activities for the remainder of 2011 will include the issuance of commercial paper under our revolving credit facilities. We also anticipate accessing the markets for other long-term financing to fund our ongoing capital expansion program.

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests and 0.1 million general partner units to Spectra Energy, resulting in total net proceeds of $218 million to Spectra Energy Partners ($213 million to Spectra Energy). The sale of the units decreased Spectra Energy s ownership in Spectra Energy Partners from 69% to 64%. On July 1, 2011, Spectra Energy Partners acquired Big Sandy from EQT for approximately $390 million in cash. See Notes 2 and 18 of Notes to Condensed Consolidated Financial Statements for further discussions.

RESULTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(in millions)			
Operating revenues	$ 1,188	$ 1,063	$ 2,800	$ 2,543
Operating expenses	786	721	1,845	1,709
Gains on sales of other assets and other, net			4	
Operating income	402	342	959	834
Other income and expenses	180	83	292	209
Interest expense	159	158	314	317
Earnings from continuing operations before income taxes	423	267	937	726
Income tax expense from continuing operations	125	76	264	173
Income from continuing operations	298	191	673	553
Income from discontinued operations, net of tax	9		16	16
Net income	307	191	689	569
Net income noncontrolling interests	23	17	48	37
Net income controlling interests	$ 284	$ 174	$ 641	$ 532

Three and Six Months Ended June 30, 2011 Compared to Same Periods in 2010

Operating Revenues. Operating revenues for the three and six months ended June 30, 2011 increased by $125 million, or 12%, and $257 million, or 10%, respectively, compared to the same periods in 2010. The increases were driven mainly by:

an increase in customer usage of natural gas due to weather that was colder than the same periods in the prior year at Distribution,

the effects of a stronger Canadian dollar on revenues at Distribution and Western Canada Transmission & Processing,

revenues from the acquisition of Bobcat Gas Storage (Bobcat) and expansion projects at U.S. Transmission and Western Canada Transmission & Processing, and higher NGL and other petroleum products sales volumes from the Empress operations due to higher demand for NGL products caused in part by colder weather as well as the effect of a scheduled plant turnaround in 2010, and higher NGL sales prices associated with the Empress operations in 2011 at Western Canada Transmission & Processing, partially offset by

lower natural gas prices passed through to customers at Distribution.

Operating Expenses. Operating expenses for the three and six months ended June 30, 2011 increased by $65 million, or 9%, and $136 million, or 8%, respectively, compared to the same periods in 2010. The increases were driven mainly by:

- higher volumes of natural gas sold as a result of weather that was colder than the same periods in the prior year at Distribution,
- the effects of a stronger Canadian dollar at Distribution and Western Canada Transmission & Processing, and
- higher volumes of natural gas purchased attributable to higher demand for NGL products caused in part by colder weather as well as the effect of a scheduled plant turnaround in 2010, and higher prices of natural gas purchased caused primarily by higher extraction premiums at the Empress operations at Western Canada Transmission & Processing, partially offset by
- lower natural gas prices passed through to customers at Distribution.

Operating Income. Operating income for the three and six months ended June 30, 2011 increased by $60 million, or 18%, and $125 million, or 15%, respectively, compared to the same periods in 2010. The increases were mainly driven by higher earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, the effects of a stronger Canadian dollar and an increase in customer usage of natural gas due to colder weather at Distribution.

Other Income and Expenses. Other income and expenses for the three and six months ended June 30, 2011 increased by $97 million, or 117%, and $83 million, or 40%, respectively, compared to the same periods in 2010. The increases were attributable to higher equity earnings from Field Services mainly due to higher commodity prices, lower interest expense and lower income tax expense, partially offset by higher planned operating expenses and the negative effects of severe weather.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and six months ended June 30, 2011 increased by $49 million and $91 million, respectively, compared to the same periods in 2010, as a result of higher earnings from continuing operations in 2011 and favorable tax audit settlements totaling $24 million in the first quarter of 2010.

The effective tax rates for income from continuing operations for the three-month periods ended June 30, 2011 and June 30, 2010 were 29.6% and 28.5%, respectively, and 28.2% and 23.8% for six-month periods. The higher effective tax rates in 2011 include an increase in state tax rates and a reduction in the domestic production activities deduction. Favorable tax audit settlements in the first quarter of 2010 also contributed to the lower rate in the 2010 six-month period.

Income from Discontinued Operations, Net of Tax. Income from discontinued operations, net of tax for the three months ended June 30, 2011 increased $9 million compared to the same period in 2010. The six-month period in 2011 was at the same level as the six-month period in 2010. The 2011 quarter included partial recovery of losses incurred in the fourth quarter of 2010 related to a breach by a third party of certain scheduled propane deliveries to us. Higher income from propane deliveries and the recovery of losses in the six-month period in 2011 were offset by a favorable income tax adjustment related to previously discontinued operations in first quarter of 2010.

Net Income Noncontrolling Interests. Net income from noncontrolling interests for the three and six months ended June 30, 2011 increased by $6 million and $11 million, respectively, compared to the same periods in 2010. The increases were primarily driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, primarily as a result of their acquisition of an additional 24.5% in Gulfstream Natural Gas System, LLC (Gulfstream) in the fourth quarter of 2010.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

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Segment Results

We evaluate segment performance based on EBIT from continuing operations less noncontrolling interests related to those earnings. On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments EBIT. We consider segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

Our segment EBIT may not be comparable to similarly titled measures of other companies because other companies may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table and detailed discussions follow:

EBIT by Business Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in millions)			
U.S. Transmission	$ 243	$ 223	$ 522	$ 470
Distribution	88	73	255	219
Western Canada Transmission & Processing	113	69	254	188
Field Services	138	58	219	157
Total reportable segment EBIT	582	423	1,250	1,034
Other	(29)	(16)	(53)	(30)
Total reportable segment and other EBIT	553	407	1,197	1,004
Interest expense	159	158	314	317
Interest income and other (a)	29	18	54	39
Earnings from continuing operations before income taxes.	$ 423	$ 267	$ 937	$ 726

(a) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT. Noncontrolling interests as presented in the following segment-level discussions includes only noncontrolling interests related to EBIT of non-wholly owned subsidiaries. It does not include noncontrolling interests related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

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U.S. Transmission

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase (Decrease)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 457	$ 442	$ 15	$ 940	$ 899	$ 41
Operating expenses						
Operating, maintenance and other	156	165	(9)	302	317	(15)
Depreciation and amortization	67	64	3	134	128	6
Gains on sales of other assets and other, net				4		4
Operating income	234	213	21	508	454	54
Other income and expenses	32	29	3	63	55	8
Noncontrolling interests	23	19	4	49	39	10
EBIT	$ 243	$ 223	$ 20	$ 522	$ 470	$ 52
Proportional throughput, TBtu (a)	623	567	56	1,426	1,385	41

(a) Trillion British thermal units. Revenues are not significantly affected by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

Three Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $15 million increase was driven by:

- a $37 million increase from expansion projects and the acquisition of Bobcat in August 2010, partially offset by
- a $9 million decrease from lower contracted volumes and rates as a result of revisions or terminations of contracts,
- a $9 million decrease in recoveries of electric power and other costs passed through to customers, and
- a $5 million decrease in processing revenues associated with pipeline operations caused by lower volumes.

Operating, Maintenance and Other. The $9 million decrease was driven by:

- a $9 million decrease in electric power and other costs passed through to customers, and
- a $4 million decrease in operating expenses due to timing and miscellaneous adjustments, partially offset by
- a $6 million increase from expansion projects and the acquisition of Bobcat.

EBIT. The $20 million increase was mainly due to higher earnings from expansion projects.

Six Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $41 million increase was driven mainly by:

- a $69 million increase from expansion projects and the acquisition of Bobcat in August 2010, partially offset by
- a $16 million decrease in recoveries of electric power and other costs passed through to customers,
- a $9 million decrease in processing revenues associated with pipeline operations caused by lower volumes, and
- a $3 million decrease from lower contracted volumes and rates as a result of revisions or terminations of contracts.

Operating, Maintenance and Other. The $15 million decrease was driven mainly by:

a $17 million decrease in electric power and other costs passed through to customers, and

an $11 million decrease in operating expenses due to timing and miscellaneous adjustments, partially offset by

a $12 million increase from the expansion projects and the acquisition of Bobcat.

Depreciation and Amortization. The $6 million increase was mainly driven by expansion projects placed in service in 2010 and the acquisition of Bobcat.

Other Income and Expenses. The $8 million increase was due to higher allowance for funds used during construction-equity (AFUDC-equity) in 2011 as a result of higher capital spending and higher equity earnings from Gulfstream, Steckman Ridge and Southeast Supply Header, LLC.

Noncontrolling Interests. The $10 million increase was driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, as a result of their acquisition of an additional 24.5% in Gulfstream in the fourth quarter 2010.

EBIT. The $52 million increase was mainly due to higher earnings from expansion projects.

Distribution

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase (Decrease)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 375	$ 331	$ 44	$ 1,071	$ 999	$ 72
Operating expenses						
Natural gas purchased	127	110	17	496	481	15
Operating, maintenance and other	107	99	8	214	202	12
Depreciation and amortization	53	49	4	106	97	9
EBIT	$ 88	$ 73	$ 15	$ 255	$ 219	$ 36
Number of customers, thousands				1,348	1,331	17
Heating degree days, Fahrenheit	930	682	248	4,702	4,003	699
Pipeline throughput, TBtu	156	181	(25)	487	485	2
Canadian dollar exchange rate, average	0.97	1.03	(0.06)	0.98	1.04	(0.06)

Three Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $44 million increase was driven by:

a $47 million increase in customer usage of natural gas due to weather that was more than 36% colder than the second quarter of 2010, and a $21 million increase resulting from a stronger Canadian dollar, partially offset by

a $29 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are based on the 12 month New York Mercantile Exchange (NYMEX) forecast.

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Natural Gas Purchased. The $17 million increase was driven by:

- a $40 million increase due to higher volumes of natural gas sold as a result of weather that was more than 36% colder than the second quarter of 2010, and
- an $8 million increase resulting from a stronger Canadian dollar, partially offset by
- a $29 million decrease from lower natural gas prices passed through to customers.

Operating, Maintenance and Other. The $8 million increase was driven primarily by a stronger Canadian dollar.

Depreciation and Amortization. The $4 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $15 million increase was mainly a result of higher usage due to colder weather and a stronger Canadian dollar.

Six Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $72 million increase was driven mainly by:

- a $124 million increase in customer usage of natural gas due to weather that was more than 17% colder than the same period in 2010,
- a $58 million increase resulting from a stronger Canadian dollar, and
- a $13 million increase from growth in the number of customers, partially offset by
- a $122 million decrease from lower natural gas prices passed through to customers.

Natural Gas Purchased. The $15 million increase was driven mainly by:

- a $104 million increase due to higher volumes of natural gas sold as a result of weather that was more than 17% colder than the same period in 2010,
- a $27 million increase resulting from a stronger Canadian dollar, and
- a $10 million increase due to growth in the number of customers, partially offset by
- a $122 million decrease from lower natural gas prices passed through to customers.

Operating, Maintenance and Other. The $12 million increase was driven primarily by a stronger Canadian dollar.

Depreciation and Amortization. The $9 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $36 million increase was mainly a result of higher usage due to colder weather, a stronger Canadian dollar and growth in the number of customers.

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Western Canada Transmission & Processing

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase (Decrease)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 371	$ 289	$ 82	$ 810	$ 644	$ 166
Operating expenses						
Natural gas and petroleum products purchased	67	46	21	189	127	62
Operating, maintenance and other	147	135	12	280	250	30
Depreciation and amortization	48	36	12	94	78	16
Operating income	109	72	37	247	189	58
Other income and expenses	4	(3)	7	7	(1)	8
EBIT	$ 113	$ 69	$ 44	$ 254	$ 188	$ 66
Pipeline throughput, TBtu	166	150	16	349	300	49
Volumes processed, TBtu	174	163	11	350	326	24
Empress inlet volumes, TBtu	129	91	38	310	278	32
Canadian dollar exchange rate, average	0.97	1.03	(0.06)	0.98	1.04	(0.06)

Three Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $82 million increase was driven by:

- a $22 million increase as a result of a stronger Canadian dollar,
- a $20 million increase in gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson area,
- a $15 million increase due to higher NGL sales prices associated with the Empress operations, and
- a $15 million increase due to higher NGL and other petroleum products sales volumes caused primarily by a scheduled plant turnaround at the Empress operations in 2010.

Natural Gas and Petroleum Products Purchased. The $21 million increase was driven by:

- a $10 million increase due primarily to higher volumes in 2011, due in part to the 2010 scheduled plant turnaround at the Empress operations as discussed above,
- a $7 million increase as a result of higher prices of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, and

a $4 million increase due to a stronger Canadian dollar.

Operating, Maintenance and Other. The $12 million increase was driven by:

a $9 million increase due to a stronger Canadian dollar, and

a $7 million increase due primarily to gathering and processing plant turnarounds, partially offset by

a $9 million decrease due to the Empress plant turnaround in 2010.

Depreciation and Amortization. The $12 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred as well as a stronger Canadian dollar.

EBIT. The $44 million increase was driven mainly by higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due primarily to a plant turnaround in the second quarter of 2010, and a stronger Canadian dollar.

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Six Months Ended June 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $166 million increase was driven by:

- a $45 million increase as a result of a stronger Canadian dollar,
- a $43 million increase due to higher NGL and other petroleum products sales volumes associated with the Empress operations resulting from higher demand for NGL products caused in part by colder weather, as well as the effect of the scheduled plant turnaround in 2010,
- a $38 million increase in gathering and processing revenues due primarily to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson area,
- a $16 million increase due to higher NGL sales prices associated with the Empress operations, and
- a $12 million increase from recovery of carbon and other non-income tax expense from customers.

Natural Gas and Petroleum Products Purchased. The $62 million increase was driven by:

- a $28 million increase due primarily to higher volumes at the Empress operations resulting from higher demand for NGL products caused in part by colder weather, as well as the effect of the scheduled plant turnaround in 2010 at the Empress operations as discussed above,
- a $23 million increase as a result of higher prices of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, and
- an $11 million increase due to a stronger Canadian dollar.

Operating, Maintenance and Other. The $30 million increase was driven by:

- a $16 million increase due to a stronger Canadian dollar,
- a $12 million increase in carbon and other non-income tax expense, and
- a $7 million increase due primarily to gathering and processing plant turnarounds, partially offset by
- a $9 million decrease due to the Empress plant turnaround in 2010.

Depreciation and Amortization. The $16 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred, as well as a stronger Canadian dollar.

EBIT. The $66 million increase was driven mainly by higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due mainly to colder weather in 2011 and a plant turnaround in the second quarter of 2010, and a stronger Canadian dollar.

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Field Services

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase (Decrease)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	$ 138	$ 58	$ 80	$ 219	$ 157	$ 62
EBIT	$ 138	$ 58	$ 80	$ 219	$ 157	$ 62
Natural gas gathered and processed/transported, TBtu/d (a,b)	6.9	6.8	0.1	6.8	6.8	
NGL production, MBbl/d (a,c)	377	361	16	367	357	10
Average natural gas price per MMBtu (d)	$ 4.31	$ 4.09	$ 0.22	$ 4.21	$ 4.70	$ (0.49)
Average NGL price per gallon (e)	$ 1.24	$ 0.91	$ 0.33	$ 1.19	$ 1.00	$ 0.19
Average crude oil price per barrel (f)	$ 102.56	$ 78.03	$ 24.53	$ 98.33	$ 78.37	$ 19.96

(a) Reflects 100% of volumes.
(b) Trillion British thermal units per day.
(c) Thousand barrels per day.
(d) Million British thermal units. Average price based on NYMEX Henry Hub.
(e) Does not reflect results of commodity hedges.
(f) Average price based on NYMEX calendar month.

Three Months Ended June 30, 2011 Compared to Same Period in 2010

EBIT. Higher equity earnings of $80 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $65 million increase from commodity-sensitive processing arrangements due to increased NGL, natural gas and crude oil prices,
- a $15 million increase due to favorable results from NGL trading and gas marketing, and
- a $9 million decrease in interest expense due to favorable rates and lower average debt balances in 2011, partially offset by
- a $7 million decrease due to higher planned operating expenses largely resulting from DCP Partners growth from acquisitions, increased repairs and maintenance costs and increased benefits costs.

Six Months Ended June 30, 2011 Compared to Same Period in 2010

EBIT. Higher equity earnings of $62 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $74 million increase from commodity-sensitive processing arrangements due to increased NGL and crude oil prices, net of decreased natural gas prices, a $15 million decrease in interest expense due to favorable rates and lower average debt balances in 2011, and

an $11 million increase attributable to decreased income tax expense related to the de-recognition of certain deferred tax assets in the 2010 period, partially offset by

a $27 million decrease due to higher planned operating expenses largely resulting from DCP Partners growth from acquisitions, increased repairs and maintenance costs and increased benefits costs, and

a $14 million decrease in gathering and processing margins attributable to lower volumes and recoveries across higher-margin regions due to the impact of severe weather which reduced production and lowered margins.

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Other

	Three Months Ended June 30, 2011	2010	Increase (Decrease)	Six Months Ended June 30, 2011	2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 16	$ 14	$ 2	$ 33	$ 27	$ 6
Operating expenses	44	30	14	83	54	29
Operating loss	(28)	(16)	(12)	(50)	(27)	(23)
Other income and expenses	(1)		(1)	(3)	(3)	
EBIT	$ (29)	$ (16)	$ (13)	$ (53)	$ (30)	$ (23)

Three Months Ended June 30, 2011 Compared to Same Period in 2010

EBIT. The $13 million decrease in EBIT reflects higher captive insurance reserves.

Six Months Ended June 30, 2011 Compared to Same Period in 2010

EBIT. The $23 million decrease in EBIT reflects an increase in reserves for captive insurance for miscellaneous loss events and higher corporate costs, including employee and retiree benefit costs.

Impairment of Goodwill

We completed our annual goodwill impairment test as of April 1, 2011 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions used in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term growth rates used for our reporting units reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transportation capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants. We assumed a weighted average long-term growth rate of 3.7% for our 2011 goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of our reporting units, except for the Distribution reporting unit, there would have been no impairment of goodwill. The Distribution reporting unit used a long-term growth rate assumption at the lower end of our growth rate range as a result of lower long-term projections of natural gas conversions and sustained mild economic growth in this region and therefore has a higher sensitivity to growth rate declines. Approximately $902 million of goodwill is allocated to our Distribution segment.

We continue to monitor the effects of the economic downturn that global economies are currently facing on the long-term cost of capital utilized to calculate our reporting unit fair values. In evaluating our reporting units for our 2011 goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 7.0% to 8.2% that market participants would use. Had we assumed a 100 basis point increase in the weighted- average cost of capital for each of our reporting units, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assume that the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

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Based on the results of our annual impairment testing, the fair values of our reporting units at April 1, 2011 significantly exceeded their carrying values. No triggering events or changes in circumstances occurred during the period April 1, 2011 (our testing date) through June 30, 2011 that would warrant re-testing for goodwill impairment.

LIQUIDITY AND CAPITAL RESOURCES

Net working capital was negative $247 million as of June 30, 2011, which included short-term borrowings and commercial paper totaling $577 million and current maturities of long-term debt of $66 million. Net working capital also included $390 million of cash held for the purchase of Big Sandy on July 1, 2011. We will rely primarily upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for the next 12 months.

We also have access to four revolving credit facilities, with available combined capacities of approximately $2.2 billion at June 30, 2011. With the exception of the Spectra Energy Partners facility which is used for bank borrowings, these facilities are used principally as back-stops for commercial paper programs or for the issuance of letters of credit. At Union Gas, we primarily use commercial paper to support our short-term working capital fluctuations. At Spectra Capital and Westcoast, we primarily use commercial paper for temporary funding of our capital expenditures. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and variable-rate debt. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and Financing Cash Flows and Liquidity for a discussion of effective shelf registrations.

Total debt balances since year-end 2010 have remained fairly flat at about $11.3 billion. Financing activities in 2011 included a decrease in commercial paper balances and refinanced long-term debt at very favorable rates. A stronger Canadian dollar also contributed to higher Canadian debt balances.

Operating Cash Flows

Net cash provided by operating activities increased $507 million to $1,338 million for the six months ended June 30, 2011 compared to the same period in 2010, driven mainly by:

- lower refunds to Union Gas customers in the first half of 2011 for gas purchase costs collected in 2010 compared to refunds in 2010 for collections in 2009,
- lower net tax payments in 2011 primarily as a result of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which deferred a significant amount of tax payments to future periods, and
- higher earnings across all segments in 2011.

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Investing Cash Flows

Net cash flows used in investing activities increased $50 million to $571 million in the first six months of 2011 compared to the same period in 2010. This change was driven primarily by higher capital and investment expenditures in 2011 from capital expansion projects in western Canada and the northeastern United States, partially offset by net proceeds from sales of Spectra Energy Partners AFS securities in 2011 that were previously pledged as collateral against its term debt that was repaid.

	Six Months Ended June 30,	
	2011	2010
	(in millions)	
Capital and Investment Expenditures		
U.S. Transmission	$ 294	$ 250
Distribution	117	77
Western Canada Transmission & Processing	313	159
Other	19	14
Total	$ 743	$ 500

Capital and investment expenditures for the six months ended June 30, 2011 consisted of $459 million for expansion projects and $284 million for maintenance and other projects.

Excluding the acquisition of Big Sandy discussed below, we continue to project 2011 capital and investment expenditures of approximately $2.1 billion, consisting of approximately $1.0 billion for U.S. Transmission, $0.3 billion for Distribution and $0.8 billion for Western Canada Transmission & Processing. Total projected 2011 capital and investment expenditures include approximately $1.3 billion of expansion capital expenditures and $0.8 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. We continue to assess short and long-term market requirements and will adjust our capital plans as required.

On July 1, 2011, Spectra Energy Partners completed the acquisition of Big Sandy for approximately $390 million in cash. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion.

Financing Cash Flows and Liquidity

Net cash used in financing activities totaled $361 million in the first six months of 2011 compared to $368 million used in financing activities in the first six months of 2010. This change was driven mainly by:

- proceeds of $213 million in 2011 from the issuance of Spectra Energy Partners common units, and

- $53 million of net debt issuances in the 2011 period compared to $346 million of net retirements in 2010, mostly offset by

- a $258 million decrease in short-term borrowings and commercial paper outstanding in 2011 compared to a $334 million increase in 2010.

On June 9, 2011, Spectra Energy Partners issued $500 million aggregate principal amount of unsecured senior notes, including $250 million of 2.95% senior notes due in 2016 and $250 million of 4.60% senior notes due in 2021. Net proceeds from the offering were used to repay all of the outstanding borrowings under Spectra Energy Partners term loan and a significant portion of the funds borrowed under its credit facility. The remaining balance of the proceeds was used for general corporate purposes.

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $218 million (net proceeds to Spectra Energy were

$213 million), used to fund a portion of the acquisition of Big Sandy.

On June 21, 2011, Union Gas issued 300 million Canadian dollars (approximately $309 million) of 4.88% notes due in 2041. Net proceeds from the offering were used for general corporate purposes, including refinancing of prior maturities of debt.

Available Credit Facilities and Restrictive Debt Covenants. In May 2011, Westcoast entered into a new 300 million Canadian dollar credit facility that expires in May 2015, which replaced its 200 million Canadian dollar credit facility that was scheduled to expire in June 2011. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and related financial and other covenants.

The terms of our Spectra Capital credit agreement require our consolidated debt-to-total-capitalization ratio to be 65% or lower. As of June 30, 2011, this ratio was 54%. Our equity and, as a result, this ratio, are sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations. Based on the strength of our total capitalization as of June 30, 2011, it is unlikely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Credit Ratings

	Standard and Poor s	Moody s Investor Service	Fitch Ratings	DBRS
As of June 30, 2011				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern Transmission, LP (a)	BBB+	Baa1	BBB+	n/a
Westcoast (a)	BBB+	n/a	n/a	A (low)
Union Gas (a)	BBB+	n/a	n/a	A
Maritimes & Northeast Pipeline, L.L.C. (a)	BBB	Baa3	n/a	n/a
M&N LP (b)	A	A2/A3	n/a	A
Spectra Energy Partners (a)	BBB	Baa3	BBB	n/a

(a) Represents senior unsecured credit rating.
(b) Represents senior secured credit rating. The A2 rating applies to M&N LP s 6.9% notes due 2019 and the A3 rating applies to its 4.34% notes due 2019.
n/a Indicates not applicable.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 65% of estimated annual net income from controlling interests per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. A dividend of $0.26 per common share was declared on July 1, 2011 and will be paid on September 12, 2011.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, respectively. Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of limited partner common units and various debt securities. As of June 30, 2011, Spectra Energy Partners had $336 million in the aggregate available for issuance under this shelf registration statement. In addition, as of June 30, 2011, certain of our subsidiaries in Canada had 1.5 billion Canadian dollars (approximately $1.5 billion) available for issuance in the Canadian market under debt shelf prospectuses.

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OTHER ISSUES

Pipeline Safety Laws and Regulations. Laws, regulations and policies regarding pipeline safety may be enacted or changed in the future as a result of various pipeline incidents in 2010 on systems unrelated to ours. Consistent with our advisor of choice business strategy, we are engaged with policy makers to ensure that the importance of pipeline operations and the delivery of natural gas in interstate commerce is taken into consideration in any such policy development. See Item 1A. Risk Factors for further discussion.

New Accounting Pronouncements. See Note 21 of Notes to Condensed Consolidated Financial Statements for discussion.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Our exposure to market risk is described in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010. We believe our exposure to market risk has not changed materially since then.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2011, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended June 30, 2011 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

We have no material pending legal proceedings that are required to be disclosed hereunder. For information regarding other legal proceedings, including regulatory and environmental matters, see Notes 4 and 16 of Notes to Condensed Consolidated Financial Statements, which information is incorporated by reference into this Part II.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, which could materially affect our financial condition or future results. Other than the risk factor below, there have been no material changes to those risk factors.

We are subject to pipeline safety laws and regulations, compliance with which can require significant capital expenditures, can increase our cost of operations and may affect or limit our business plans.

Our interstate pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

In 2010, serious pipeline incidents on systems unrelated to ours focused the attention of Congress and the public on pipeline safety. Legislative proposals have been introduced in Congress that would strengthen the PHMSA s enforcement and penalty authority, and expand the scope of its oversight. The PHMSA has initiated an evaluation of its existing regulations and appears to be considering substantial revisions in its regulations. The PHMSA also has issued guidance that states it will focus near-term enforcement efforts on recordkeeping and integrity management, following urgent National Transportation Safety Board recommendations related to pipeline pressure and recordkeeping. Because it is uncertain what legislation or regulatory changes will be enacted, we cannot determine the impact that such legislation or regulatory changes may have on our operations or financial condition at this time. Pipeline failures or failure to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by the PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it could have a material adverse effect on our operations, earnings, financial condition and cash flows.

Item 6. Exhibits.

Any agreements included as exhibits to this Form 10-Q may contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

- were not intended to be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement;
- may apply contract standards of materiality that are different from materiality under the applicable securities laws; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement.

We acknowledge that, notwithstanding the inclusion of the foregoing cautionary statements, we are responsible for considering whether additional specific disclosures of material information regarding material contractual provisions are required to make the statements in this Form 10-Q not misleading.

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(a) Exhibits

Exhibit Number	
+10.1	Spectra Energy Corp 2007 Long-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on April 22, 2011).
+10.2	Spectra Energy Corp Executive Short-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on April 22, 2011).
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

+ Management contract or compensatory plan or arrangement.
* Filed herewith.

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

SIGNATURES

Pursuant to the requirements 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.

SPECTRA ENERGY CORP

Date: August 8, 2011

/s/ Gregory L. Ebel
Gregory L. Ebel
President and Chief Executive Officer

Date: August 8, 2011

/s/ J. Patrick Reddy
J. Patrick Reddy
Chief Financial Officer