DEVON ENERGY CORP/DE
Form 10-Q
May 04, 2011

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2011

or

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

Commission File Number 001-32318

DEVON ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**73-1567067**
(State of other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*
20 North Broadway, Oklahoma City, Oklahoma	**73102-8260**
(Address of principal executive offices)	*(Zip code)*

Registrant s telephone number, including area code: (405) 235-3611

Former name, former address and former fiscal year, if changed from last report: Not applicable

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 þ No o

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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

On April 25, 2011, 423.0 million shares of common stock were outstanding.

DEVON ENERGY CORPORATION
FORM 10-Q
For the Quarterly Period Ended March 31, 2011
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DEFINITIONS

Measurements of Oil, Natural Gas and Natural Gas Liquids

NGL or NGLs means natural gas liquids.

Oil includes crude oil and condensate.

Bbl means barrel of oil. One barrel equals 42 U.S. gallons.

MBbls means thousand barrels.

MMBbls means million barrels.

MBbls/d means thousand barrels per day.

Mcf means thousand cubic feet of natural gas.

MMcf means million cubic feet.

Bcf means billion cubic feet.

Bcfe means billion cubic feet equivalent.

MMcf/d means million cubic feet per day.

Boe means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

MBoe means thousand Boe.

MMBoe means million Boe.

MBoe/d means thousand Boe per day.

Btu means British thermal units, a measure of heating value.

MMBtu means million Btu.

MMBtu/d means million Btu per day.

Geographic Areas

Canada means the operations of Devon encompassing oil and gas properties located in Canada.

International means the discontinued operations of Devon that encompass oil and gas properties that lie outside the United States and Canada.

North America Onshore means the operations of Devon encompassing oil and gas properties in the continental United States and Canada.

U.S. Offshore means the divested operations of Devon that encompassed oil and gas properties in the Gulf of Mexico.

U.S. Onshore means the properties of Devon encompassing oil and gas properties in the continental United States.

Other

Federal Funds Rate means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

Inside FERC refers to the publication Inside F.E.R.C. s Gas Market Report.

LIBOR means London Interbank Offered Rate.

NYMEX means New York Mercantile Exchange.

SEC means United States Securities and Exchange Commission.

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare the December 31, 2010 reserve reports and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, expect, intend, project, estimate, anticipate, believe, or continue or similar terminology. Although we belie expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

energy markets, including the supply and demand for oil, gas, NGLs and other products or services, as well as the prices of oil, gas, NGLs and other products or services, including regional pricing differentials;

production levels, including Canadian production subject to government royalties, which fluctuate with prices and production;

reserve levels;

competitive conditions;

technology;

the availability of capital resources within the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks;

capital expenditure and other contractual obligations;

currency exchange rates;

the weather;

inflation;

the availability of goods and services;

drilling risks;

future processing volumes and pipeline throughput;

general economic conditions, whether internationally, nationally or in the jurisdictions in which we or our subsidiaries conduct business;

public policy and government regulatory changes, including changes in royalty, production tax and income tax regimes, changes in hydraulic fracturing regulation and changes in environmental laws, regulation and liability;

terrorism;

- occurrence of property acquisitions or divestitures; and

- other factors disclosed in Devon s 2010 Annual Report on Form 10-K under Item 1A. Risk Factors, Item 2. Properties, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

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PART I. Financial Information

Item 1. ***Consolidated Financial Statements***

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	March 31, 2011 (Unaudited)	December 31, 2010
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,311	$ 2,866
Short-term investments	1,636	145
Accounts receivable	1,269	1,202
Current assets held for sale	533	563
Other current assets	850	779
Total current assets	5,599	5,555
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	58,028	56,012
Not subject to amortization	3,508	3,434
Total oil and gas	61,536	59,446
Other	4,609	4,429
Total property and equipment, at cost	66,145	63,875
Less accumulated depreciation, depletion and amortization	(45,064)	(44,223)
Property and equipment, net	21,081	19,652
Goodwill	6,151	6,080
Long-term assets held for sale	913	859
Other long-term assets	806	781
Total assets	$ 34,550	$ 32,927
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,353	$ 1,411
Revenues and royalties due to others	639	538
Short-term debt	3,003	1,811
Current liabilities associated with assets held for sale	264	305
Other current liabilities	495	518
Total current liabilities	5,754	4,583

Long-term debt	3,800	3,819
Asset retirement obligations	1,468	1,423
Liabilities associated with assets held for sale	34	26
Other long-term liabilities	1,066	1,067
Deferred income taxes	3,199	2,756
Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 425.2 million and 431.9 million shares in 2011 and 2010, respectively	43	43
Additional paid-in capital	5,028	5,601
Retained earnings	12,230	11,882
Accumulated other comprehensive earnings	1,951	1,760
Treasury stock, at cost. 0.3 million and 0.4 million shares in 2011 and 2010, respectively	(23)	(33)
Total stockholders equity	19,229	19,253
Commitments and contingencies (Note 10)		
Total liabilities and stockholders equity	$ 34,550	$ 32,927

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31,	
	2011	2010
	(Unaudited) (In millions, except per share amounts)	
Revenues:		
Oil, gas and NGL sales	$ 1,860	$ 2,070
Oil, gas and NGL derivatives	(168)	620
Marketing and midstream revenues	455	530
Total revenues	2,147	3,220
Expenses and other, net:		
Lease operating expenses	424	414
Taxes other than income taxes	108	101
Marketing and midstream operating costs and expenses	333	397
Depreciation, depletion and amortization of oil and gas properties	442	426
Depreciation and amortization of non-oil and gas properties	64	63
Accretion of asset retirement obligations	23	26
General and administrative expenses	130	138
Restructuring costs	(5)	
Interest expense	81	86
Interest-rate and other financial instruments	(17)	(15)
Other, net	(16)	(4)
Total expenses and other, net	1,567	1,632
Earnings from continuing operations before income taxes	580	1,588
Income tax (benefit) expense:		
Current	(89)	299
Deferred	280	215
Total income tax expense	191	514
Earnings from continuing operations	389	1,074
Discontinued operations:		
Earnings from discontinued operations before income taxes	30	137
Discontinued operations income tax expense	3	19
Earnings from discontinued operations	27	118
Net earnings	$ 416	$ 1,192

Basic net earnings per share:		
Basic earnings from continuing operations per share	$ 0.91	$ 2.40
Basic earnings from discontinued operations per share	0.06	0.27
Basic net earnings per share	$ 0.97	$ 2.67
Diluted net earnings per share:		
Diluted earnings from continuing operations per share	$ 0.91	$ 2.39
Diluted earnings from discontinued operations per share	0.06	0.27
Diluted net earnings per share	$ 0.97	$ 2.66

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS

	Three Months Ended March 31, 2011	2010
	(Unaudited) (In millions)	
Net earnings	$ 416	$ 1,192
Foreign currency translation:		
Change in cumulative translation adjustment	195	222
Foreign currency translation income tax expense	(10)	(12)
Foreign currency translation total	185	210
Pension and postretirement benefit plans:		
Recognition of net actuarial loss and prior service cost in earnings	9	8
Pension and postretirement benefit plans income tax expense	(3)	(3)
Pension and postretirement benefit plans total	6	5
Other comprehensive earnings, net of tax	191	215
Comprehensive earnings	$ 607	$ 1,407

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders Equity
	(Unaudited) (In millions)						
Three Months Ended March 31, 2011:							
Balance as of December 31, 2010	432	$ 43	$ 5,601	$ 11,882	$ 1,760	$ (33)	$ 19,253
Net earnings				416			416
Other comprehensive earnings, net of tax					191		191
Stock option exercises	1		88				88
Common stock repurchased						(696)	(696)
Common stock retired	(8)		(706)			706	
Common stock dividends				(68)			(68)
Share-based compensation			36				36
Share-based compensation tax benefits			9				9
Balance as of March 31, 2011	425	$ 43	$ 5,028	$ 12,230	$ 1,951	$ (23)	$ 19,229
Three Months Ended March 31, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$	$ 15,570
Net earnings				1,192			1,192
Other comprehensive earnings, net of tax					215		215
Stock option exercises			8				8
Common stock repurchased						(2)	(2)
Common stock retired			(2)			2	
Common stock dividends				(72)			(72)
Share-based compensation			41				41
Share-based compensation tax benefits			3				3
Balance as of March 31, 2010	447	$ 45	$ 6,577	$ 8,733	$ 1,600	$	$ 16,955

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net earnings	$ 416	$ 1,192
Earnings from discontinued operations, net of tax	(27)	(118)
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	506	489
Deferred income tax expense	280	215
Unrealized change in fair value of financial instruments	253	(523)
Other noncash charges	36	56
Net (increase) decrease in working capital	(171)	50
Increase in long-term other assets	(4)	(2)
Decrease in long-term other liabilities	(23)	(18)
Cash from operating activities continuing operations	1,266	1,341
Cash from operating activities discontinued operations	(6)	154
Net cash from operating activities	1,260	1,495
Cash flows from investing activities:		
Capital expenditures	(1,827)	(1,247)
Purchases of short-term investments	(1,636)	
Redemptions of short-term investments	145	
Redemptions of long-term investments		8
Proceeds from property and equipment divestitures	5	1,257
Other	(9)	
Cash from investing activities continuing operations	(3,322)	18
Cash from investing activities discontinued operations	(52)	(107)
Net cash from investing activities	(3,374)	(89)
Cash flows from financing activities:		
Net commercial paper borrowings (repayments)	1,197	(1,192)
Proceeds from stock option exercises	88	8
Repurchases of common stock	(706)	
Dividends paid on common stock	(68)	(72)
Excess tax benefits related to share-based compensation	9	3
Net cash from financing activities	520	(1,253)

Effect of exchange rate changes on cash	20	18
Net (decrease) increase in cash and cash equivalents	(1,574)	171
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	3,290	1,011
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 1,716	$ 1,182

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

The accompanying unaudited consolidated financial statements and notes of Devon Energy Corporation (Devon) have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted. The accompanying consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes included in Devon s 2010 Annual Report on Form 10-K.

The unaudited interim consolidated financial statements furnished in this report reflect all adjustments that are, in the opinion of management, necessary to a fair statement of Devon s financial position as of March 31, 2011 and Devon s results of operations and cash flows for the three-month periods ended March 31, 2011 and 2010.

2. Accounts Receivable

The components of accounts receivable include the following:

	March 31, 2011	December 31, 2010
	(In millions)	
Oil, gas and NGL sales	$ 811	$ 786
Marketing and midstream revenues	204	165
Joint interest billings	181	182
Other	83	79
Gross accounts receivable	1,279	1,212
Allowance for doubtful accounts	(10)	(10)
Net accounts receivable	$ 1,269	$ 1,202

3. Derivative Financial Instruments

Objectives and Strategies

Devon periodically enters into commodity and interest rate derivative financial instruments. These instruments are used to manage the inherent uncertainty of future revenues due to oil, gas and NGL price volatility and to manage exposure to interest rate volatility. Devon does not hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Devon s derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options. Under the terms of the price swaps, Devon receives a fixed price for its production and pays a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional gas index prices and pays a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon will cash-settle the difference with the counterparty to the collars. Under the terms of the call options, Devon sold to counterparties the right to purchase production at a predetermined price.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility. Devon s interest rate swaps include contracts in which Devon receives a fixed rate and pays a variable rate on a total notional amount. Devon also has forward starting swaps. Under the terms of the forward starting swaps, Devon will net settle these contracts in September 2011 or sooner should Devon elect. The net settlement amount will be based upon Devon paying a fixed rate and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041.

Counterparty Risk

By using derivative financial instruments to manage exposures to changes in commodity prices and interest rates, Devon

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom Devon believes are minimal credit risks. It is Devon s policy to enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers. Additionally, Devon s derivative contracts generally require cash collateral to be posted if either its or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of Devon s contracts. As of March 31, 2011, the credit ratings of all Devon s counterparties were investment grade.

Commodity Derivatives

As of March 31, 2011, Devon had the following open oil derivative positions:

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q2-Q4 2011			45,000	$ 75.00	$ 108.89	19,500	$ 95.00
Q1-Q4 2012	9,000	$ 104.20	35,000	$ 82.14	$ 126.42	19,500	$ 95.00

As of March 31, 2011, Devon had the following open natural gas derivative positions:

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Q2 2011	912,500	$ 5.24	350,000	$ 4.18	$ 4.68		
Q3 2011	712,500	$ 5.51					
Q4 2011	712,500	$ 5.51					
Q1-Q4 2012	130,000	$ 5.06				487,500	$ 6.00

Basis Swaps

Production Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q2-Q4 2011	Panhandle Eastern Pipeline	150,000	$ 0.33

As of March 31, 2011, Devon had the following open NGL derivative positions:

Basis Swaps

	Volume	Weighted Average

Production Period	Pay	(Bbls/d)		Differential to WTI ($/Bbl)
Q2-Q4 2011	Natural Gasoline	500	$	9.75
Q1-Q4 2012	Natural Gasoline	500	$	10.10
Q1-Q4 2013	Natural Gasoline	500	$	6.80

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Interest Rate Derivatives

As of March 31, 2011, Devon had the following open interest rate swap derivative positions:

Fixed-to-Floating Swaps

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$300	4.30%	Six month LIBOR	July 18, 2011
100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$1,150	3.82%		

Forward Starting Swaps

Notional (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$950	3.92%	Three month LIBOR	September 30, 2011

Financial Statement Presentation

The following table presents the derivative fair values included in the accompanying consolidated balance sheets.

	Balance Sheet Caption	March 31, 2011	December 31, 2010
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 183	$ 248
Commodity derivatives	Other long-term assets	2	1
Interest rate derivatives	Other current assets	112	100
Interest rate derivatives	Other long-term assets	29	40
Total asset derivatives		$ 326	$ 389
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 225	$ 50
Commodity derivatives	Other long-term liabilities	157	142

Total liability derivatives	$ 382	$ 192

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying consolidated statements of operations associated with these derivative financial instruments.

	Statement of Operations Caption	Three Months Ended March 31, 2011	2010
		(In millions)	
Cash settlements:			
Commodity derivatives	Oil, gas and NGL derivatives	$ 86	$ 96
Interest rate derivatives	Interest-rate and other financial instruments	16	16
Total cash settlements		102	112
Unrealized (losses) gains:			
Commodity derivatives	Oil, gas and NGL derivatives	(254)	524
Interest rate derivatives	Interest-rate and other financial instruments	1	(1)
Total unrealized (losses) gains		(253)	523
Net (loss) gain recognized on statement of operations		$ (151)	$ 635

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

4. Other Current Assets

The components of other current assets include the following:

	March 31, 2011	December 31, 2010
	(In millions)	
Income taxes receivable	$ 374	$ 270
Derivative financial instruments	295	348
Inventories	116	120
Other	65	41
Other current assets	$ 850	$ 779

5. Goodwill

During the first three months of 2011, Devon s Canadian goodwill increased $71 million entirely due to foreign currency translation.

6. Debt

Credit Lines

Devon has a $2,650 million syndicated, unsecured revolving line of credit (the Senior Credit Facility). As of March 31, 2011, Devon had no borrowings under the Senior Credit Facility.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon s ratio of total funded debt to total capitalization to be less than 65 percent. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of March 31, 2011, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at March 31, 2011, as calculated pursuant to the terms of the agreement, was 17.7 percent.

Commercial Paper

In March 2011, Devon s Board of Directors authorized an increase in its commercial paper program from $2.2 billion to $5.0 billion. Commercial paper debt generally has a maturity of between one and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market.

Although Devon began and ended the first quarter of 2011 with approximately $3.4 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from its 2010 International divestitures. Based on Devon s evaluation of future cash needs across its operations in the United States and Canada, these proceeds remain outside of the United States.

Consequently, during the first quarter of 2011, Devon borrowed $1,197 million of commercial paper in the United States primarily to fund capital expenditures, common stock repurchases and dividends in excess of cash flow generated by its United States operating activities. As of March 31, 2011, Devon s average borrowing rate on its $1,197 million of commercial paper borrowings was 0.30 percent.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

7. Asset Retirement Obligations

The schedule below summarizes changes in Devon s asset retirement obligations.

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,497	$ 1,513
Liabilities incurred	11	16
Liabilities settled	(18)	(47)
Revision of estimated obligation	3	205
Liabilities assumed by others		(8)
Accretion expense on discounted obligation	23	26
Foreign currency translation adjustment	21	22
Asset retirement obligations as of end of period	1,537	1,727
Less current portion	69	90
Asset retirement obligations, long-term	$ 1,468	$ 1,637

During the first quarter of 2010, Devon recognized a revision to its asset retirement obligations totaling $205 million. The increase was primarily due to an overall increase in abandonment cost estimates and a decrease in the discount rate used to calculate the present value of the obligations.

8. Retirement Plans

The following table presents the components of net periodic benefit cost for Devon s pension and other postretirement benefit plans.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2011	2010	2011	2010
	(In millions)			
Net periodic benefit cost:				
Service cost	$ 9	$ 8	$	$
Interest cost	15	14	1	1
Expected return on plan assets	(10)	(9)		
Amortization of prior service cost	1	1		
Net actuarial loss	8	7		
Net periodic benefit cost	$ 23	$ 21	$ 1	$ 1

Devon previously disclosed in its financial statements for the year ended December 31, 2010, that it expected to contribute $84 million to its qualified pension plans in 2011. Devon now expects to contribute $346 million to its qualified pension plans in 2011, including $32 million that was contributed in the first quarter. The increase in Devon s 2011 estimated contribution is due to increased discretionary funding.

9. Stockholders Equity

Stock Repurchases

During the first quarter of 2011, Devon repurchased 8.1 million common shares under its $3.5 billion stock repurchase program announced in 2010 for $696 million, or $85.95 per share. Through the end of the first quarter of 2011, Devon had repurchased 26.4 million common shares for $1.9 billion, or $71.83 per share, under this program, which expires December 31, 2011.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

Dividends

Devon paid common stock dividends of $68 million and $72 million (quarterly rates of $0.16 per share) in the first quarter of 2011 and 2010, respectively. In March 2011, Devon announced an increase of its quarterly cash dividend to $0.17 per share that will begin in the second quarter of 2011.

10. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon s estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon s financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management s estimate.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act and similar state statutes. In response to liabilities associated with these activities, loss accruals primarily consist of estimated uninsured costs associated with remediation. Devon s monetary exposure for environmental matters is not expected to be material.

Royalty Matters

Numerous natural gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates, which resulted in underpayment of royalties in connection with natural gas and NGLs produced and sold from federal and Indian owned or controlled lands. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon s knowledge, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

11. Fair Value Measurements

Certain of Devon s assets and liabilities are reported at fair value in the accompanying consolidated balance sheets. Such assets and liabilities include amounts for both financial and non-financial instruments. The following tables provide carrying value and fair value measurement information for Devon s financial assets and liabilities.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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(Unaudited)

The carrying values of cash and cash equivalents, accounts receivable, other current receivables, accounts payable and other current payables and accrued expenses included in the accompanying consolidated balance sheets approximated fair value at March 31, 2011 and December 31, 2010. These assets and liabilities are not presented in the following table.

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
	(In millions)				
March 31, 2011 assets (liabilities):					
Short-term investments	$ 1,636	$ 1,636	$ 1,636	$	$
Long-term investments	$ 94	$ 94	$	$	$ 94
Commodity derivatives	$ 185	$ 185	$	$ 185	$
Commodity derivatives	$ (382)	$ (382)	$	$ (382)	$
Interest rate derivatives	$ 141	$ 141	$	$ 141	$
Debt	$ (6,803)	$ (7,726)	$ (1,197)	$ (6,410)	$ (119)
December 31, 2010 assets (liabilities):					
Short-term investments	$ 145	$ 145	$ 145	$	$
Long-term investments	$ 94	$ 94	$	$	$ 94
Commodity derivatives	$ 249	$ 249	$	$ 249	$
Commodity derivatives	$ (192)	$ (192)	$	$ (192)	$
Interest rate derivatives	$ 140	$ 140	$	$ 140	$
Debt	$ (5,630)	$ (6,629)	$	$ (6,485)	$ (144)

Devon s Level 3 fair value measurements included in the table above relate to certain long-term investments and a non-interest bearing promissory note. Included below is a summary of the changes in Devon s Level 3 fair value measurements during the first three months of 2011 and 2010.

	Three Months Ended March 31, 2011	2010
	(In millions)	
Long-term investments balance at beginning of period	$ 94	$ 115
Redemptions of principal		(8)
Long-term investments balance at end of period	$ 94	$ 107

	Three Months Ended March 31, 2011	2010
	(In millions)	
Debt balance at beginning of period	$ (144)	$
Foreign exchange translation adjustment	(3)	

Accretion of promissory note	(1)	
Redemptions of principal	29	
Debt balance at end of period	$ (119)	$

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
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(Unaudited)

12. Restructuring Costs

In the fourth quarter of 2009, Devon announced plans to divest its offshore assets. As of March 31, 2011, Devon had divested all of its U.S. Offshore assets and a significant part of its International assets. Devon has entered into agreements to sell its remaining offshore assets in Brazil and Angola and is waiting for the respective governments to approve the divestitures.

Through the end of the first quarter of 2011, Devon had incurred $207 million of restructuring costs associated with these divestitures. This amount is comprised of $127 million of employee severance costs, $77 million associated with abandoned office leases and $3 million of other miscellaneous costs.

Financial Statement Presentation

The schedule below summarizes activity and balances associated with Devon s restructuring liabilities. There was no activity during the first quarter of 2010.

	Continuing Operations			Discontinued Operations		
	Other Current Liabilities	Other Long-Term Liabilities	Total	Other Current Liabilities	Other Long-Term Liabilities	Total
			(In millions)			
Balance as of December 31, 2010	$ 31	$ 51	$ 82	$ 16	$	$ 16
Cash severance settled	(8)		(8)	(1)		(1)
Lease obligations settled	(3)	(4)	(7)			
Cash severance revision				6		6
Lease obligations revision	(3)	(1)	(4)			
Balance as of March 31, 2011	$ 17	$ 46	$ 63	$ 21	$	$ 21
Balance as of March 31, 2010	$ 61	$	$ 61	$ 23	$	$ 23

The schedule below summarizes the components of restructuring costs in the accompanying 2011 consolidated statement of operations. No restructuring costs were recorded in the three months ended March 31, 2010.

	Three Months Ended March 31, 2011		
	Continuing Operations	Discontinued Operations	Total
		(In millions)	
Cash severance	$	$ 6	$ 6
Share-based awards	(1)		(1)
Lease obligations	(4)		(4)
Restructuring costs	$ (5)	$ 6	$ 1

13. Discontinued Operations

Revenues related to Devon s discontinued operations totaled $43 million and $212 million in the three months ended March 31, 2011 and March 31, 2010, respectively. Earnings from discontinued operations before income taxes totaled $30 million and $137 million in the three months ended March 31, 2011 and March 31, 2010, respectively.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

The following table presents the main classes of assets and liabilities associated with Devon s discontinued operations.

	March 31, 2011	December 31, 2010
	(In millions)	
Cash and cash equivalents	$ 405	$ 424
Accounts receivable	18	43
Other current assets	110	96
Current assets	$ 533	$ 563
Property and equipment, net	$ 875	$ 848
Other long-term assets	38	11
Total long-term assets	$ 913	$ 859
Accounts payable	$ 229	$ 260
Other current liabilities	35	45
Current liabilities	$ 264	$ 305
Long-term liabilities	$ 34	$ 26

14. Earnings Per Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share.

	Earnings	Common Shares	Earnings per Share
	(In millions, except per share amounts)		
Three Months Ended March 31, 2011:			
Earnings from continuing operations	$ 389	428	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	385	423	$ 0.91
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 385	425	$ 0.91

Three Months Ended March 31, 2010:			
Earnings from continuing operations	$ 1,074	447	
Attributable to participating securities	(13)	(6)	
Basic earnings per share	1,061	441	$ 2.40
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 1,061	443	$ 2.39

Certain options to purchase shares of Devon s common stock are excluded from the dilution calculations because the options are antidilutive. These excluded options totaled 3.1 million and 6.4 million during the three-month periods ended March 31, 2011 and 2010, respectively.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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15. Segment Information

Devon manages its North American onshore operations through distinct operating segments, or divisions, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its United States divisions into one reporting segment due to the similar nature of the businesses. However, Devon s Canadian and International divisions are reported as separate reporting segments primarily due to significant differences in the respective regulatory environments.

	U.S.	Canada	International	Total
		(In millions)		
As of March 31, 2011:				
Current assets	$ 2,641	$ 2,425	$ 533	$ 5,599
Property and equipment, net	13,314	7,767		21,081
Goodwill	3,046	3,105		6,151
Other assets	431	375	913	1,719
Total assets	$ 19,432	$ 13,672	$ 1,446	$ 34,550
Current liabilities	$ 2,996	$ 2,494	$ 264	$ 5,754
Long-term debt	2,502	1,298		3,800
Asset retirement obligations	565	903		1,468
Other liabilities	1,002	64	34	1,100
Deferred income taxes	1,896	1,303		3,199
Stockholders equity	10,471	7,610	1,148	19,229
Total liabilities and stockholders equity	$ 19,432	$ 13,672	$ 1,446	$ 34,550

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

	U.S.	Canada (In millions)	Total
Three Months Ended March 31, 2011:			
Revenues:			
Oil, gas and NGL sales	$ 1,212	$ 648	$ 1,860
Oil, gas and NGL derivatives	(168)		(168)
Marketing and midstream revenues	423	32	455
Total revenues	1,467	680	2,147
Expenses and other, net:			
Lease operating expenses	208	216	424
Taxes other than income taxes	94	14	108
Marketing and midstream operating costs and expenses	308	25	333
Depreciation, depletion and amortization of oil and gas properties	260	182	442
Depreciation and amortization of non-oil and gas properties	58	6	64
Accretion of asset retirement obligations	9	14	23
General and administrative expenses	91	39	130
Restructuring costs	(5)		(5)
Interest expense	37	44	81
Interest-rate and other financial instruments	(17)		(17)
Other, net	(14)	(2)	(16)
Total expenses and other, net	1,029	538	1,567
Earnings from continuing operations before income taxes	438	142	580
Income tax (benefit) expense:			
Current	(88)	(1)	(89)
Deferred	243	37	280
Total income tax expense	155	36	191
Earnings from continuing operations	$ 283	$ 106	$ 389
Capital expenditures, before revision of future asset retirement obligations	$ 1,250	$ 532	$ 1,782
Revision of future asset retirement obligations	(11)	14	3
Capital expenditures, continuing operations	$ 1,239	$ 546	$ 1,785

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(Unaudited)

	U.S.	Canada (In millions)	Total
Three Months Ended March 31, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,370	$ 700	$ 2,070
Oil, gas and NGL derivatives	625	(5)	620
Marketing and midstream revenues	496	34	530
Total revenues	2,491	729	3,220
Expenses and other, net:			
Lease operating expenses	224	190	414
Taxes other than income taxes	90	11	101
Marketing and midstream operating costs and expenses	369	28	397
Depreciation, depletion and amortization of oil and gas properties	261	165	426
Depreciation and amortization of non-oil and gas properties	56	7	63
Accretion of asset retirement obligations	13	13	26
General and administrative expenses	108	30	138
Interest expense	30	56	86
Interest-rate and other financial instruments	(15)		(15)
Other, net	(3)	(1)	(4)
Total expenses and other, net	1,133	499	1,632
Earnings from continuing operations before income taxes	1,358	230	1,588
Income tax expense (benefit):			
Current	214	85	299
Deferred	235	(20)	215
Total income tax expense	449	65	514
Earnings from continuing operations	$ 909	$ 165	$ 1,074
Capital expenditures, before revision of future asset retirement obligations	$ 1,033	$ 370	$ 1,403
Revision of future asset retirement obligations	83	122	205
Capital expenditures, continuing operations	$ 1,116	$ 492	$ 1,608

16. Supplemental Information to Statements of Cash Flows

Three Months Ended March 31,

	2011	2010
	(In millions)	
Net (increase) decrease in working capital:		
Increase in accounts receivable	$ (60)	$ (78)
Increase in other current assets	(110)	(2)
Increase (decrease) in accounts payable	45	(29)
Increase in revenues and royalties due to others	100	58
(Decrease) increase in other current liabilities	(146)	101
Net (increase) decrease in working capital	$ (171)	$ 50
Supplementary cash flow data total operations:		
Interest paid (net of capitalized interest)	$ 137	$ 137
Income taxes paid	$ 9	$ 50

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

The following discussion and analysis addresses material changes in our results of operations and capital resources and uses for the three-month period ended March 31, 2011, compared to the three-month period ended March 31, 2010, and in our financial condition and liquidity since December 31, 2010. For information regarding our critical accounting policies and estimates, see our 2010 Annual Report on Form 10-K under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Financial Overview

During the first three months of 2011 and 2010, we generated net earnings of $416 million, or $0.97 per diluted share, and $1.2 billion, or $2.66 per diluted share, for the respective periods. The primary drivers for the decrease in earnings were unrealized gains recognized on our commodity hedges in 2010 and lower gas prices in 2011. In addition, the 2010 results include operating earnings from our offshore properties that were divested subsequent to the first quarter of 2010.

Key measures of our financial performance for the first three months of 2011 compared to the first three months of 2010 are summarized below:

North America Onshore oil and NGL production increased 11% to 19 MMBbls.

North America Onshore gas production increased 5% to 228 Bcf.

The combined realized price without hedges for oil, gas and NGLs decreased 11% to $32.86 per Boe.

Oil, gas and NGL derivatives incurred a net loss of $168 million in the first three months of 2011 and generated a net gain of $620 million in the first three months of 2010. Included in these amounts were cash receipts of $86 million and $96 million, respectively.

Marketing and midstream operating profit decreased 9% to $122 million.

Per unit operating costs increased 1% to $7.48 per Boe.

Operating cash flow decreased 16% to $1.3 billion.

Capital spending totaled approximately $1.8 billion in the first quarter of 2011.

Our performance and the proceeds from our previous offshore divestitures have allowed us to maintain a robust level of liquidity. As of March 31, 2011, we held $3.4 billion in cash and short-term investments, access to short-term commercial paper borrowings and our $2.7 billion credit facility. With this liquidity, we continue executing our exploration and development programs, with a focus on growing our liquids production, and repurchasing common shares under our $3.5 billion share repurchase program. Through April 25, 2011, we had repurchased 28.3 million shares for $2.1 billion, or $72.98 per share.

First-Quarter Operating Highlights

Production from our Cana-Woodford Shale play averaged a record 162 million cubic feet of natural gas equivalent per day in the first quarter of 2011. This represents a 120 percent increase compared to the first-quarter of 2010.

In the Permian Basin, oil and natural gas liquids production increased 17 percent over the first-quarter 2010. In aggregate, liquids production accounted for nearly 75 percent of the 44,000 equivalent barrels per day produced in the Permian Basin during the first quarter.

In Canada, we plan to commence steam injection at Jackfish 2 in May with first production expected by year-end. At full production, Jackfish 2 is expected to produce 35,000 barrels per day before royalties for more than 20 years.

Immediately adjacent to our Jackfish lease, we successfully completed the drilling of 135 appraisal wells on our Pike oil sands lease. The results were consistent with our expectations and will assist in determining the optimal development configuration. We anticipate filing a regulatory application for the first phase of Pike in the first half of 2012.

Net production from the Barnett Shale exceeded 1.2 billion cubic feet of natural gas equivalent per day in the first quarter, including 43,000 barrels per day of liquids. This was an 11 percent increase over the first quarter of 2010.

We brought six operated Granite Wash wells online in the first quarter. Initial production from these wells averaged 1,760 barrels of oil-equivalent per day, including 250 barrels of oil and 490 barrels of natural gas liquids per day. We have an average working interest of 84 percent in these wells.

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Results of Operations

Revenues

	Three Months Ended March 31, 2011	2010	Change (1)
Oil Volumes (MMBbls)			
U.S. Onshore	3	3	+23%
Canada	7	7	+1%
North America Onshore	10	10	+8%
U.S. Offshore		1	-100%
Total	10	11	-4%
Gas Volumes (Bcf)			
U.S. Onshore	177	166	+7%
Canada	51	50	+1%
North America Onshore	228	216	+5%
U.S. Offshore		10	-100%
Total	228	226	+1%
NGLs Volumes (MMBbls)			
U.S. Onshore	8	7	+16%
Canada	1	1	+1%
North America Onshore	9	8	+14%
U.S. Offshore			-100%
Total	9	8	+12%
Total Volumes (MMBoe)			
U.S. Onshore	41	37	+10%
Canada	16	16	+1%
North America Onshore	57	53	+7%
U.S. Offshore		3	-100%
Total	57	56	+1%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

	Three Months Ended March 31, 2011 (1)	2010 (1)	Change
Oil Prices (per Bbl)			

U.S. Onshore	$ 88.73	$ 74.81	+19%
Canada	$ 60.86	$ 62.50	-3%
North America Onshore	$ 70.95	$ 66.41	+7%
U.S. Offshore	$	$ 76.99	N/M
Total	$ 70.95	$ 67.58	+5%
Gas Prices (per Mcf)			
U.S. Onshore	$ 3.50	$ 4.66	-25%
Canada	$ 4.03	$ 5.08	-21%
North America Onshore	$ 3.62	$ 4.76	-24%
U.S. Offshore	$	$ 5.63	N/M
Total	$ 3.62	$ 4.80	-25%
NGLs Prices (per Bbl)			
U.S. Onshore	$ 35.41	$ 34.22	+3%
Canada	$ 54.18	$ 48.95	+11%
North America Onshore	$ 37.39	$ 35.98	+4%
U.S. Offshore	$	$ 40.59	N/M
Total	$ 37.39	$ 36.09	+4%
Combined Prices (per Boe)			
U.S. Onshore	$ 29.77	$ 32.81	-9%
Canada	$ 40.78	$ 44.50	-8%
North America Onshore	$ 32.86	$ 36.29	-9%
U.S. Offshore	$	$ 51.07	N/M
Total	$ 32.86	$ 37.07	-11%

(1) The prices presented exclude any effects due to oil, gas and NGL derivatives.

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The volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales between the three months ended March 31, 2011 and 2010.

	Oil	Gas	NGLs	Total
		(In millions)		
2010 sales	$ 710	$ 1,086	$ 274	$ 2,070
Changes due to volumes	(25)	7	32	14
Changes due to prices	34	(269)	11	(224)
2011 sales	$ 719	$ 824	$ 317	$ 1,860

Oil Sales

Oil sales decreased $25 million in the first three months of 2011 due to a 4 percent decrease in production. The decrease was primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010, partially offset by an 8 percent increase in our North America Onshore production. The increased North America Onshore production resulted primarily from continued development of our Permian Basin properties and our Jackfish thermal heavy oil project in Canada.

Oil sales increased $34 million in the first three months of 2011 as a result of a 5 percent increase in our realized price without hedges. The largest contributor to the increase in our realized price was the increase in the average NYMEX West Texas Intermediate index price over the same time period. This was partially offset by an increase in our price differential based upon the NYMEX index. The larger differential resulted primarily from the widening of the heavy oil differentials related to our Canadian operations.

Gas Sales

A 1 percent increase in production during the first quarter of 2011 caused gas sales to increase by $7 million. The increase was comprised of the net effect of a 5 percent increase in our North America Onshore production, partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010. The increased North America Onshore production resulted primarily from continued development activities in the Barnett and Cana-Woodford Shales, partially offset by natural declines in our other operating areas.

Gas sales decreased $269 million during the first three months of 2011 as a result of a 25 percent decrease in our realized price without hedges. This decrease was largely due to decreases in the North American regional index prices upon which our gas sales are based.

NGL Sales

NGL sales increased $32 million in the first quarter of 2011 due to a 12 percent increase in production. The increase in production was primarily due to increased drilling in North America Onshore areas that have liquids-rich gas.

NGL sales increased $11 million during the first three months of 2011 as a result of a 4 percent increase in our realized price without hedges. This increase was largely due to an increase in the Mont Belvieu, Texas index price over the same time period.

Oil, Gas and NGL Derivatives

The following tables provide financial information associated with our oil, gas and NGL hedges. The first table presents the cash settlements and unrealized gains and losses recognized as components of our revenues. The subsequent tables present our oil, gas and NGL prices with, and without, the effects of the cash settlements. The prices do not include the effects of unrealized gains and losses.

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
Cash settlement receipts (payments):		
Gas derivatives	$ 91	$ 96
Oil derivatives	(5)	
Total cash settlements	86	96
Unrealized (losses) gains on fair value changes:		
Gas derivatives	(57)	520
Oil derivatives	(198)	4
NGL derivatives	1	
Total unrealized (losses) gains on fair value changes	(254)	524
Oil, gas and NGL derivatives	$ (168)	$ 620

	Three Months Ended March 31, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 70.95	$ 3.62	$ 37.39	$ 32.86
Cash settlements of hedges	(0.48)	0.39	0.06	1.52
Realized price, including cash settlements	$ 70.47	$ 4.01	$ 37.45	$ 34.38

	Three Months Ended March 31, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 67.58	$ 4.80	$ 36.09	$ 37.07
Cash settlements of hedges		0.42		1.71
Realized price, including cash settlements	$ 67.58	$ 5.22	$ 36.09	$ 38.78

Our oil, gas and NGL derivatives include price swaps, costless collars and basis swaps. For the price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. The price collars set a floor and ceiling price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we cash-settle the difference with the counterparty to the collars. For the basis swaps, we receive a fixed differential between two regional gas index prices and pay a variable differential on the same two index prices to the contract counterparty. Cash settlements as presented in the tables above represent realized gains or losses related to these various instruments.

Additionally, to enhance a portion of our natural gas price swaps, we have sold gas call options for 2012 and oil call options for 2011 and 2012. The call options give counterparties the right to purchase production at a predetermined price.

During the first three months of 2011, we received $91 million, or $0.39 per Mcf, from counterparties to settle our gas derivatives and paid $5 million, or $0.48 per Bbl, to counterparties to settle our oil derivatives. During the first three months of 2010, we received $96 million, or $0.42 per Mcf, from counterparties to settle our gas derivatives.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil, gas and NGL derivative instruments in each reporting period. We estimate the fair values of these derivatives primarily by using internal discounted cash flow calculations. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Based on the amount of volumes subject to our gas derivative financial instruments at March 31, 2011, a 10 percent increase in these forward curves would have increased our unrealized losses by approximately $163 million. A 10 percent increase in the forward curves associated with our oil derivatives would have increased our unrealized losses by approximately $302 million. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility. Finally, the amount of production subject to oil, gas and NGL derivatives is not a variable in our cash flow calculations, but it does impact the total derivative value.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with fourteen counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of March 31, 2011, the credit ratings of all our counterparties were investment grade.

Including the cash settlements discussed above, our oil, gas and NGL derivatives incurred a net loss of $168 million during the first three months of 2011 and generated a net gain of $620 million during the first three months of 2010. In addition to the impact of cash settlements, these net gains and losses were impacted by new positions and settlements that occurred during each period, as well as the relationships between contract prices and the associated forward curves. A summary of our outstanding oil, gas and NGL derivative positions as of March 31, 2011 is included in Item 3. Quantitative and Qualitative Disclosures About Market Risk of this report.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Three Months Ended March 31,		
	2011	2010	Change(1)
	($ in millions)		
Marketing and midstream:			
Revenues	$ 455	$ 530	-14%
Operating costs and expenses	333	397	-16%
Operating profit	$ 122	$ 133	-9%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

Marketing and midstream revenues decreased $75 million and operating costs and expenses decreased $64 million, causing operating profit to decrease $11 million. These decreases were primarily due to lower natural gas prices, partially offset by increased natural gas throughput.

Lease Operating Expenses (LOE)

	Three Months Ended March 31,		
	2011	2010	Change(1)
Lease operating expenses ($ in millions):			
U.S. Onshore	$ 208	$ 191	+9%
Canada	216	190	+13%
North America Onshore	424	381	+11%
U.S. Offshore		33	-100%
Total	$ 424	$ 414	+2%
Lease operating expenses per Boe:			
U.S. Onshore	$ 5.11	$ 5.12	-0%
Canada	$ 13.55	$ 12.09	+12%
North America Onshore	$ 7.48	$ 7.19	+4%

U.S. Offshore	$	$ 11.18	N/M
Total	$ 7.48	$ 7.41	+1%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

LOE increased $10 million in the first three months of 2011. This amount consisted of a $43 million increase related to our North America Onshore operations and a $33 million decrease related to our U.S. Offshore operations that were sold in the second quarter of 2010. Our 7 percent increase in North America Onshore production increased LOE by $27 million. Additionally, North America Onshore LOE increased $12 million due to changes in the exchange rate between the U.S. and Canadian dollars. The higher exchange rate was also the main contributor to the increases in North America Onshore and total LOE per Boe.

Taxes Other Than Income Taxes

	Three Months Ended March 31,		
	2011	2010	Change(1)
	($ in millions)		
Production	$ 56	$ 59	-5%
Ad valorem	50	40	+26%
Other	2	2	+34%
Total	$ 108	$ 101	+8%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

Production taxes decreased $3 million due to a slight decrease in our U.S. Onshore revenues. Ad valorem taxes increased $10 million due to higher estimated assessed values of our oil and gas property and equipment.

Depreciation, Depletion and Amortization of Oil and Gas Properties (DD&A)

	Three Months Ended March 31,		
	2011	2010	Change(1)
Total production volumes (MMBoe)	57	56	+1%
DD&A rate ($ per Boe)	$ 7.80	$ 7.63	+2%
DD&A expense ($ in millions)	$ 442	$ 426	+4%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

The following table details the changes in DD&A of oil and gas properties between the three months ended March 31, 2011 and 2010 (in millions).

2010 DD&A	$ 426
Change due to rate	10
Change due to volumes	6
2011 DD&A	$ 442

Oil and gas property-related DD&A increased $10 million during the first three months of 2011 due to a 2 percent increase in the DD&A rate. The largest contributors to the higher rate were our drilling and development activities subsequent to the end of the first quarter of 2010 and changes in the exchange rate between the U.S. and Canadian dollars. These increases were largely offset by a decrease in the rate due to our 2010 U.S. offshore property divestitures.

General and Administrative Expenses (G&A)

	Three Months Ended March 31,		
	2011	2010	Change(1)
	($ in millions)		
Gross G&A	$ 238	$ 245	-3%
Capitalized G&A	(81)	(80)	+1%

Reimbursed G&A	(27)	(27)	0%
Net G&A	$ 130	$ 138	-6%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

Gross and net G&A decreased primarily due to lower employee compensation and benefits resulting from our 2010 offshore divestitures.

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Interest Expense

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
Interest based on debt outstanding	$ 98	$ 105
Capitalized interest	(20)	(21)
Other	3	2
Total interest expense	$ 81	$ 86

Interest based on debt outstanding decreased primarily due to the early redemption of our 7.25 percent $350 million senior notes in the second quarter of 2010.

Interest-Rate and Other Financial Instruments

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
(Gains) losses from interest rate swaps:		
Cash settlements	$ (16)	$ (16)
Unrealized fair value changes	(1)	1
Total	$ (17)	$ (15)

During the first three months of 2011 and 2010, we received cash settlements totaling $16 million from counterparties to settle our interest rate swaps.

In addition to recognizing cash settlements, we recognize unrealized changes in the fair values of our interest rate swaps each reporting period. We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers. In the first three months of 2011, we recorded an unrealized gain of $1 million as a result of changes in interest rates. In the first three months of 2010, we recorded an unrealized loss of $1 million as a result of changes in interest rates.

The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by a third party. Based on the notional amount subject to the interest rate swaps at March 31, 2011, a 10% increase in these forward curves would have increased our unrealized gain for our interest rate swaps by approximately $69 million.

Similar to our commodity derivative contracts, counterparty credit risk is also a component of interest rate derivative valuations. We have mitigated our exposure to any single counterparty by contracting with seven separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. The credit ratings of all our counterparties were investment grade as of March 31, 2011.

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Income Taxes

The following table presents our total income tax expense and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate.

	Three Months Ended March 31,	
	2011	**2010**
Total income tax expense (in millions)	$ 191	$ 514
U.S. statutory income tax rate	35%	35%
State income taxes	1%	1%
Taxation on Canadian operations	(2%)	(1%)
Other	(1%)	(3%)
Effective income tax expense rate	33%	32%

Earnings From Discontinued Operations

The following table presents the components of our earnings from discontinued operations. The decrease in earnings is primarily due to our 2010 asset divestitures.

	Three Months Ended March 31,	
	2011	**2010**
Total production (MMBoe)	1	3
Combined price without hedges (per Boe)	$ 81.94	$ 72.65
	(In millions)	
Operating revenues	$ 43	$ 212
Expenses and other, net:		
Operating expenses	26	78
Restructuring costs	6	
Other, net	(19)	(3)
Total expenses and other, net	13	75
Earnings before income taxes	30	137
Income tax expense	3	19
Earnings from discontinued operations	$ 27	$ 118

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Capital Resources, Uses and Liquidity

The following discussion of capital resources and liquidity should be read in conjunction with the consolidated statements of cash flows included in Part I, Item 1.

Sources and Uses of Cash

	Three Months Ended March 31, 2011	2010
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 1,266	$ 1,341
Commercial paper borrowings	1,197	
Stock option exercises	88	8
Divestitures of property and equipment	5	1,257
Other		11
Total sources of cash and cash equivalents	2,556	2,617
Uses of cash and cash equivalents:		
Capital expenditures	(1,827)	(1,247)
Net purchases of short-term investments	(1,491)	
Repurchases of common stock	(706)	
Dividends	(68)	(72)
Commercial paper repayments		(1,192)
Total uses of cash and cash equivalents	(4,092)	(2,511)
(Decrease) increase from continuing operations	(1,536)	106
(Decrease) increase from discontinued operations, net of distributions to continuing operations	(58)	47
Effect of foreign exchange rates	20	18
Net (decrease) increase in cash and cash equivalents	$ (1,574)	$ 171
Cash and cash equivalents at end of period	$ 1,716	$ 1,182
Short-term investments at end of period	$ 1,636	$

Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) continued to be a significant source of capital and liquidity in the first three months of 2011. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to noncash expenses such as DD&A, property impairments, financial instrument fair value changes and deferred income taxes. As a result, our operating cash flow decreased approximately 6 percent during 2011 primarily due to the decrease in revenues as discussed in the Results of Operations section of this report.

During the first three months of 2011, our operating cash flow funded approximately 70 percent of our cash payments for capital expenditures. Commercial paper borrowings were used to fund the remainder of our cash-based capital expenditures. During the first three months of 2010, our operating cash flow was sufficient to fund our cash payments for capital expenditures.

Other Sources of Cash Continuing and Discontinued Operations

As needed, we supplement our operating cash flow and available cash by accessing available credit under our credit facilities and commercial paper program. We may also issue long-term debt to supplement our operating cash flow while maintaining adequate liquidity under our credit facilities. Additionally, we may acquire short-term investments to maximize our income on available cash balances. As needed, we reduce such short-term investment balances to further supplement our operating cash flow and available cash. Another source of cash proceeds comes from employee stock option exercises.

During the first three months of 2011, we utilized commercial paper borrowings of $1.2 billion to fund capital expenditures, common share repurchases and dividends in excess of our operating cash flow.

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During the first three months of 2011, we received proceeds of $88 million from shares issued for employee stock option exercises.

During the first three months of 2010, we sold our interests in the Jack, St. Malo and Cascade Lower Tertiary projects in the Gulf of Mexico for $1.3 billion and used the proceeds to repay commercial paper borrowings.

Capital Expenditures

Our capital expenditures are presented by geographic area and type in the following table. The amounts in the table reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred in prior quarters. Capital expenditures actually incurred during the first three months of 2011 and 2010 were approximately $1.8 billion and $1.6 billion, respectively.

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
U.S. Onshore	$ 1,114	$ 627
Canada	520	377
North America Onshore	1,634	1,004
U.S. Offshore		126
Total exploration and development	1,634	1,130
Midstream	72	48
Other	121	69
Total continuing operations	$ 1,827	$ 1,247

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties, which totaled $1.6 billion and $1.1 billion in the first three months of 2011 and 2010, respectively. The increase in exploration and development capital spending in the first three months of 2011 was primarily due to increased drilling activities. With rising oil prices and proceeds from our 2010 offshore divestitures, we are increasing drilling primarily to grow our liquids production.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines. Our midstream capital expenditures are largely impacted by oil and gas drilling activities. Therefore, the increase in development drilling also increased midstream capital activities.

Capital expenditures related to corporate activities increased in 2011. This increase is largely driven by the construction of our new headquarters in Oklahoma City.

Short-term Investments

During the first three months of 2011, we purchased $1.6 billion of United States Treasury bills that have original maturities greater than three months and are, therefore, considered short-term investments. As of March 31, 2011, the average maturity of these short-term investments was 121 days.

Repurchases of Common Stock

During the first three months of 2011, we continued repurchasing shares under our $3.5 billion stock repurchase program announced in May 2010. Including unsettled shares, we repurchased 8.1 million common shares for $696 million, or $85.95 per share, in the first quarter of 2011. This program expires on December 31, 2011.

Dividends

Our common stock dividends were $68 million and $72 million (quarterly rates of $0.16 per share) in the first three months of 2011 and 2010, respectively.

In March 2011, we announced an increase of our quarterly cash dividend to $0.17 per share that will begin in the second quarter of 2011.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include equity and debt securities that can be issued pursuant to our automatically effective shelf registration statement filed with the SEC. Another significant source of future liquidity will be proceeds from the sales of our remaining offshore assets in Brazil and Angola. We estimate the combination of these sources of capital will be adequate to fund future capital expenditures, share repurchases, debt repayments and other contractual commitments. The following sections discuss changes to our liquidity subsequent to filing our 2010 Annual Report on Form 10-K.

Operating Cash Flow

We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, gas and NGLs produced. To mitigate some of the risk inherent in prices, we have utilized various price swap, fixed-price physical delivery and price collar contracts to set minimum and maximum prices on our 2011 production. As of March 31, 2011, approximately 34 percent of our 2011 gas production is associated with financial price swaps, collars and fixed-price physicals. We also have basis swaps associated with 0.2 Bcf per day of our 2011 gas production. Additionally, approximately 36 percent of our 2011 oil production is associated with financial price collars. We also have call options that, if exercised, would relate to an additional 16 percent of our 2011 oil production.

Looking beyond 2011, we have also entered into contracts to manage the price risk relative to our 2012 and 2013 oil, gas and NGL production. A summary of these contracts as of March 31, 2011, is included in Item 3. Quantitative and Qualitative Disclosures about Market Risk of this report.

Credit Availability

In March 2011, our Board of Directors authorized an increase in our commercial paper program from $2.2 billion to $5.0 billion.

As of April 25, 2011, we had $2.7 billion of available capacity under our syndicated, unsecured Senior Credit Facility and $1.3 billion of commercial paper borrowings outstanding.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65 percent. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders equity adjusted for noncash financial writedowns, such as full cost ceiling impairments. As of March 31, 2011, we were in compliance with this covenant. Our debt-to-capitalization ratio at March 31, 2011, as calculated pursuant to the terms of the agreement, was 17.7 percent.

Although we ended the first quarter of 2011 with $3.4 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from our International offshore divestitures. Based on our evaluation of future cash needs across our operations in the United States and Canada, these proceeds remain outside of the United States. With these proceeds remaining outside of the United States, we expect to continue to increase our commercial paper borrowings in the United States to supplement our United States based operating cash flow to fund our capital expenditure and common stock repurchase programs.

Common Stock Repurchase Program

As of April 25, 2011, we had repurchased $2.1 billion, or 28.3 million common shares at an average price of $72.98 under our $3.5 billion repurchase program. This program expires on December 31, 2011.

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Pension Funding and Estimates

We previously disclosed that we expected to contribute approximately $84 million to our qualified pension plans during 2011. We now expect to contribute $346 million to our qualified pension plans in 2011, including $32 million that was contributed in the first quarter.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodity Price Risk

We have commodity derivatives that pertain to production for the last nine months of 2011, as well as 2012 and 2013. The key terms to all our oil, gas and NGL derivative financial instruments as of March 31, 2011 are presented in the following tables.

We had the following open oil derivative positions:

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q2-Q4 2011			45,000	$ 75.00	$ 108.89	19,500	$ 95.00
Q1-Q4 2012	9,000	$ 104.20	35,000	$ 82.14	$ 126.42	19,500	$ 95.00

We had the following open natural gas derivative positions:

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Q2 2011	912,500	$ 5.24	350,000	$ 4.18	$ 4.68		
Q3 2011	712,500	$ 5.51					
Q4 2011	712,500	$ 5.51					
Q1-Q4 2012	130,000	$ 5.06				487,500	$ 6.00

Basis Swaps

Production Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q2-Q4 2011	Panhandle Eastern Pipeline	150,000	$ 0.33

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We had the following open NGL derivative positions:

Basis Swaps

Production Period	Pay	Volume (Bbls/d)		Weighted Average Differential to WTI ($/Bbl)
Q2-Q4 2011	Natural Gasoline	500	$	9.75
Q1-Q4 2012	Natural Gasoline	500	$	10.10
Q1-Q4 2013	Natural Gasoline	500	$	6.80

The fair values of our commodity derivatives presented in the tables above are largely determined by estimates of the forward curves of the relevant price indices. At March 31, 2011, a 10 percent increase in the forward curves associated with our gas derivative instruments would have increased our unrealized losses by approximately $163 million. A 10 percent increase in the forward curves associated with our oil derivative instruments would have increased our unrealized losses by approximately $302 million.

Interest Rate Risk

At March 31, 2011, we had debt outstanding of $6.8 billion. Of this amount, $5.6 billion, or 82 percent bears fixed interest rates averaging 7.1 percent. Additionally, we had $1.2 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.30 percent.

As of March 31, 2011, our interest rate swaps consisted of instruments with a total notional amount of $2.1 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.92 percent and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041. The key terms of these contracts are presented in the following tables.

Fixed-to-Floating Swaps

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$300	4.30%	Six month LIBOR	July 18, 2011
100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$1,150	3.82%		

Forward Starting Swaps

Variable

Notional (In millions)	Fixed Rate Paid	Rate Received	Expiration
$950	3.92%	Three month LIBOR	September 30, 2011

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. At March 31, 2011, a 10 percent increase in these forward curves would have increased our unrealized gain for our interest rate swaps by approximately $69 million.

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10 percent unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our March 31, 2011 balance sheet.

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Item 4. ***Controls and Procedures***

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Devon, including its consolidated subsidiaries, is made known to the officers who certify Devon s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Devon s principal executive and principal financial officers have concluded that Devon s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of March 31, 2011, to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the first quarter of 2011 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

PART II. Other Information

Item 1. ***Legal Proceedings***

There have been no material changes to the information included in Item 3. Legal Proceedings in our 2010 Annual Report on Form 10-K.

Item 1A. ***Risk Factors***

There have been no material changes to the information included in Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

2011 Period	Total Number of Shares Purchased[(1)]		Average Price Paid per Share		Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(1)] (In millions)
January 1 January 31	4,169,100	$	82.60	$	1,955
February 1 February 28	1,500,100	$	89.26	$	1,821
March 1 March 31	2,432,109	$	89.66	$	1,603
Total	8,101,309	$	85.95		

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011. As of March 31, 2011, we had repurchased 26.4 million common shares for $1.9 billion, or $71.83 per share under this program.

Item 3. ***Defaults Upon Senior Securities***

None.

Item 5. ***Other Information***

None.

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Item 6. ***Exhibits***

(a) *Exhibits* required by Item 601 of Regulation S-K are as follows:

Exhibit Number	Description
31.1	Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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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.

DEVON ENERGY CORPORATION

Date: May 4, 2011

/s/ Jeffrey A. Agosta
Jeffrey A. Agosta
Executive Vice President   Chief Financial Officer

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INDEX TO EXHIBITS

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