DEVON ENERGY CORP/DE
Form 10-Q
August 06, 2010

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 June 30, 2010

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. (Check one):

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 July 30, 2010, 435.0 million shares of common stock were outstanding.

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DEVON ENERGY CORPORATION
FORM 10-Q
For the Quarterly Period Ended June 30, 2010
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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.

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 operations of Devon encompassing 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.

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, 2009 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, continue or similar terminology. Although we believe 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, and the prices of oil, gas, NGLs, including regional pricing differentials, and other products or services;
- production levels, including Canadian production subject to government royalties, which fluctuate with prices and production, and International production governed by payout agreements, which affect reported 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, changes in environmental regulation and liability under federal, state, local or foreign environmental laws and regulations;

- terrorism;

- occurrence, timing and completion of property acquisitions or divestitures; and

- risk factors disclosed under Item 1A in our 2009 Annual Report on Form 10-K as well as other factors disclosed under Item 2. Properties Proved Reserves and Estimated Future Net Revenue, 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.

PART I. Financial Information

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	June 30, 2010 (Unaudited)	December 31, 2009
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,174	$ 646
Accounts receivable	1,205	1,208
Current assets held for sale	1,020	657
Other current assets	650	481
Total current assets	5,049	2,992
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	51,851	52,352
Not subject to amortization	3,239	4,078
Total oil and gas	55,090	56,430
Other	4,229	4,045
Total property and equipment, at cost	59,319	60,475
Less accumulated depreciation, depletion and amortization	(42,478)	(41,708)
Property and equipment, net	16,841	18,767
Goodwill	5,892	5,930
Long-term assets held for sale	1,340	1,250
Other long-term assets	849	747
Total assets	$ 29,971	$ 29,686
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,133	$ 1,137
Revenues and royalties due to others	466	486
Short-term debt	53	1,432
Current liabilities associated with assets held for sale	548	234
Other current liabilities	1,202	513
Total current liabilities	3,402	3,802

Long-term debt	5,571	5,847
Asset retirement obligations	1,346	1,418
Liabilities associated with assets held for sale	189	213
Other long-term liabilities	919	937
Deferred income taxes	1,714	1,899
Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 440.4 million and 446.7 million shares in 2010 and 2009, respectively	44	45
Additional paid-in capital	6,186	6,527
Retained earnings	9,369	7,613
Accumulated other comprehensive earnings	1,296	1,385
Treasury stock, at cost. 1.1 million shares in 2010	(65)	
Total stockholders equity	16,830	15,570
Commitments and contingencies (Note 12)		
Total liabilities and stockholders equity	$ 29,971	$ 29,686

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil, gas and NGL sales	$ 1,782	$ 1,450	$ 3,852	$ 2,825
Oil and gas derivatives	45	13	665	167
Marketing and midstream revenues	405	359	935	730
Total revenues	2,232	1,822	5,452	3,722
Expenses and other, net:				
Lease operating expenses	442	410	856	850
Taxes other than income taxes	92	79	193	168
Marketing and midstream operating costs and expenses	280	230	677	454
Depreciation, depletion and amortization of oil and gas properties	426	430	852	990
Depreciation and amortization of non-oil and gas properties	63	74	126	144
Accretion of asset retirement obligations	24	23	50	46
General and administrative expenses	130	173	268	336
Restructuring costs	(8)		(8)	
Interest expense	111	90	197	173
Non-oil and gas financial instruments	81	(10)	66	(15)
Reduction of carrying value of oil and gas properties				6,408
Other, net	(22)	24	(26)	31
Total expenses and other, net	1,619	1,523	3,251	9,585
Earnings (loss) from continuing operations before income taxes	613	299	2,201	(5,863)
Income tax expense (benefit):				
Current	707	58	1,006	50
Deferred	(446)	51	(231)	(2,221)
Total income tax expense (benefit)	261	109	775	(2,171)
Earnings (loss) from continuing operations	352	190	1,426	(3,692)
Discontinued operations:				
Earnings (loss) from discontinued operations before income taxes	473	143	610	77
Discontinued operations income tax expense	119	19	138	30

Earnings (loss) from discontinued operations	354	124	472	47
Net earnings (loss)	$ 706	$ 314	$ 1,898	$ (3,645)
Basic earnings (loss) from continuing operations per share	$ 0.79	$ 0.43	$ 3.20	$ (8.32)
Basic earnings (loss) from discontinued operations per share	0.80	0.28	1.06	0.11
Basic net earnings (loss) per share	$ 1.59	$ 0.71	$ 4.26	$ (8.21)
Diluted earnings (loss) from continuing operations per share	$ 0.79	$ 0.42	$ 3.19	$ (8.32)
Diluted earnings (loss) from discontinued operations per share	0.79	0.28	1.05	0.11
Diluted net earnings (loss) per share	$ 1.58	$ 0.70	$ 4.24	$ (8.21)

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS (LOSS)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(Unaudited) (In millions)			
Net earnings (loss)	$ 706	$ 314	$ 1,898	$ (3,645)
Foreign currency translation:				
Change in cumulative translation adjustment	(326)	467	(104)	306
Foreign currency translation income tax (expense) benefit	17	(30)	5	(19)
Foreign currency translation total	(309)	437	(99)	287
Pension and postretirement benefit plans:				
Recognition of net actuarial loss and prior service cost in earnings	8	12	16	24
Pension and postretirement benefit plans income tax expense	(3)	(4)	(6)	(8)
Pension and postretirement benefit plans total	5	8	10	16
Other comprehensive earnings (loss), net of tax	(304)	445	(89)	303
Comprehensive earnings (loss)	$ 402	$ 759	$ 1,809	$ (3,342)

See accompanying notes to consolidated financial statements.

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)						
Six Months Ended June 30, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$	$ 15,570
Net earnings (loss)				1,898			1,898
Other comprehensive earnings (loss), net of tax					(89)		(89)
Stock option exercises			15				15
Common stock repurchased						(503)	(503)
Common stock retired	(7)	(1)	(437)			438	
Common stock dividends				(142)			(142)
Share-based compensation			75				75
Share-based compensation tax benefits			6				6
Balance as of June 30, 2010	440	$ 44	$ 6,186	$ 9,369	$ 1,296	$ (65)	$ 16,830
Six Months Ended June 30, 2009:							
Balance as of December 31, 2008	444	$ 44	$ 6,257	$ 10,376	$ 383	$	$ 17,060
Net earnings (loss)				(3,645)			(3,645)
Other comprehensive earnings (loss), net of tax					303		303
Stock option exercises			9				9
Common stock repurchased						(11)	(11)
Common stock retired			(11)			11	
Common stock dividends				(142)			(142)
Share-based compensation			103				103

Share-based compensation tax benefits			5				5
Balance as of June 30, 2009	444	$ 44	$ 6,363	$ 6,589	$ 686	$	$ 13,682

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Earnings (loss) from continuing operations	$ 1,426	$ (3,692)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	978	1,134
Deferred income tax benefit	(231)	(2,221)
Reduction of carrying value of oil and gas properties		6,408
Unrealized change in fair value of financial instruments	(231)	71
Other noncash charges	81	125
Net decrease in working capital	581	52
Decrease in long-term other assets	14	25
Increase in long-term other liabilities	1	21
Cash from operating activities continuing operations	2,619	1,923
Cash from operating activities discontinued operations	273	154
Net cash from operating activities	2,892	2,077
Cash flows from investing activities:		
Proceeds from property and equipment divestitures	4,129	2
Capital expenditures	(3,221)	(2,945)
Redemptions of long-term investments	18	4
Cash from investing activities continuing operations	926	(2,939)
Cash from investing activities discontinued operations	429	(254)
Net cash from investing activities	1,355	(3,193)
Cash flows from financing activities:		
Proceeds from borrowings of long-term debt, net of issuance costs		1,187
Net commercial paper repayments	(1,432)	325
Debt repayments	(350)	(1)
Proceeds from stock option exercises	15	9
Repurchases of common stock	(430)	
Dividends paid on common stock	(142)	(142)
Excess tax benefits related to share-based compensation	6	5
Net cash from financing activities	(2,333)	1,383

Effect of exchange rate changes on cash	(9)	5
Net increase in cash and cash equivalents	1,905	272
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	1,011	384
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 2,916	$ 656

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 2009 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 June 30, 2010 and Devon s results of operations and cash flows for the three-month and six-month periods ended June 30, 2010 and 2009.

2. Accounts Receivable

The components of accounts receivable include the following:

	June 30, 2010	December 31, 2009
	(In millions)	
Oil, gas and NGL sales	$ 711	$ 752
Joint interest billings	214	151
Marketing and midstream revenues	146	188
Production tax credits	125	110
Other	19	19
Gross accounts receivable	1,215	1,220
Allowance for doubtful accounts	(10)	(12)
Net accounts receivable	$ 1,205	$ 1,208

3. Derivative Financial Instruments

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 and gas price volatility and to manage Devon s exposure to interest rate volatility. Devon has elected not to designate any of its derivative instruments for hedge accounting treatment.

The following table presents the fair values of derivative assets and liabilities included in the accompanying consolidated balance sheets.

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
June 30, 2010:			
Gas price swaps	Other current assets	$ 323	$
Gas price swaps	Other long-term assets	4	
Gas price collars	Other current assets	19	
Gas basis swaps	Other current assets	15	
Oil price collars	Other current assets	55	
Oil price collars	Other long-term assets	35	

Interest rate swaps	Other current assets	39	
Interest rate swaps	Other long-term assets	45	
Total derivatives		$ 535	$

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

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
December 31, 2009:			
Gas price swaps	Other current assets	$ 169	$
Gas basis swaps	Other current assets	3	
Oil price collars	Other current liabilities		38
Interest rate swaps	Other current assets	39	
Interest rate swaps	Other long-term assets	131	
Total derivatives		$ 342	$ 38

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Cash settlements:				
Gas price swaps (1)	$ 239	$	$ 337	$
Gas price collars (1)	12	114	13	232
Gas basis swaps (1)	1		(2)	
Interest rate swaps (2)	4	5	20	21
Total cash settlements	256	119	368	253
Unrealized gains (losses):				
Gas price swaps (1)	(332)		158	
Gas price collars (1)	(16)	(101)	19	(65)
Gas basis swaps (1)	17		12	
Oil price collars (1)	124		128	
Interest rate swaps (2)	(85)	5	(86)	(6)
Total unrealized gains (losses)	(292)	(96)	231	(71)
Net gain (loss) recognized on statement of operations	$ (36)	$ 23	$ 599	$ 182

(1) Cash settlements and unrealized gains and losses on

fair value changes associated with Devon s gas price swaps, gas price collars, gas basis swaps and oil price collars have been recorded in the Oil and gas derivatives line item in the accompanying consolidated statements of operations.

(2) Cash settlements and unrealized gains and losses on fair value changes associated with Devon s interest rate swaps have been recorded in the Non-oil and gas financial instruments line item in the accompanying consolidated statements of operations.

4. Other Current Assets

The components of other current assets include the following:

	June 30, 2010	December 31, 2009
	(In millions)	
Derivative financial instruments	$ 451	$ 211
Inventories	138	182
Other	61	88
Other current assets	$ 650	$ 481

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

5. Property and Equipment

Offshore Divestitures

In November 2009, Devon announced plans to reposition itself strategically as a high-growth, North America onshore exploration and production company. As part of this strategic repositioning, Devon is bringing forward the value of its offshore assets by divesting them.

Closed Transactions

The following table presents Devon s offshore divestiture transactions that closed in the first six months of 2010. Gross proceeds represent contract prices based upon a January 1, 2010 effective date for the Gulf of Mexico divestitures and a May 1, 2010 effective date for the China Panyu divestiture. After-tax proceeds represent gross proceeds adjusted for customary purchase price adjustments, selling costs and income taxes. The purchase price adjustments consist primarily of net cash flow subsequent to the effective date of the divestitures. Proved reserves in the following table are based upon estimated proved reserves as of the divestiture dates.

	Gross Proceeds	After-Tax Proceeds	Proved Reserves (MMBoe)
	(In millions)		(Unaudited)
Gulf of Mexico (continuing operations)	$ 4,150	$ 3,212	91
China Panyu (discontinued operations)	515	405	13
Total	$ 4,665	$ 3,617	104

Proceeds from these divestitures are being used to retire debt and repurchase Devon common shares. Additionally, Devon is using divestiture proceeds to fund North America Onshore exploration and development opportunities, including a joint-venture investment in the Pike oil sands discussed below.

Under full cost accounting rules, sales or other dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of gain or loss. However, if not recognizing a gain or loss on the disposition would otherwise significantly alter the relationship between a cost center s capitalized costs and proved reserves, then a gain or loss must be recognized.

The Gulf of Mexico divestitures presented above did not significantly alter such relationship for Devon s United States cost center. Therefore, Devon did not recognize a gain in connection with the Gulf of Mexico divestitures. Panyu was Devon s only producing property in its China cost center. As a result, Devon recognized a $308 million ($235 million after-tax) gain in connection with the Panyu divestiture. This gain is included in earnings from discontinued operations in the accompanying 2010 consolidated statements of operations.

Pending Transactions

Devon has entered into agreements to sell its Azerbaijan and Brazil assets for $5.2 billion. Devon has received the necessary government approvals for the Azerbaijan transaction, which is now scheduled to close on August 16, 2010. The Brazil transaction continues to progress through the approval process of the Brazilian government and is on track to close around the end of 2010. Devon expects to record gains when such transactions close. Devon has also entered into an agreement to sell its remaining assets in China for $0.1 billion.

Deepwater Drilling Rigs

As part of its offshore operations, Devon was leasing three deepwater drilling rigs. The Seadrill West Sirius and Ocean Endeavor deepwater drilling rigs were used in Devon s Gulf of Mexico operations. The Transocean Deepwater Discovery is being used in Devon s operations in Brazil.

In conjunction with the deepwater Gulf of Mexico divestiture that closed in the second quarter of 2010, the buyer assumed Devon s lease and remaining commitments for the Seadrill West Sirius rig. Subsequent to closing all its Gulf of Mexico

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

divestitures, Devon agreed to pay $31 million to the owner of the Ocean Endeavor rig to terminate the lease. The $31 million lease termination cost is included in oil and gas property and equipment in the accompanying June 30, 2010, consolidated balance sheet. The buyer of Devon s assets in Brazil will assume Devon s lease and remaining commitments for the Transocean Deepwater Discovery rig when the divestiture transaction closes.

Oil Sands Joint Venture

In conjunction with certain offshore divestitures in the second quarter of 2010, Devon formed a heavy oil joint venture to operate and develop the Pike oil sands leases in Alberta, Canada. As a result, Devon acquired a 50 percent interest in the Pike oil sands leases for $500 million. Devon will also fund $155 million of Canadian dollar capital costs on behalf of its joint-venture partner in the form of a non-interest bearing promissory note. The majority of the capital costs are expected to be paid during 2011 and 2012. See Note 8 for more information regarding the promissory note.

6. Goodwill

During the first six months of 2010, Devon s Canadian goodwill decreased $38 million. This decrease was entirely due to foreign currency translation.

7. Other Current Liabilities

The components of other current liabilities include the following:

	June 30, 2010	December 31, 2009
	(In millions)	
Income taxes payable	$ 752	$ 40
Accrued interest	113	120
Other	337	353
Other current liabilities	$ 1,202	$ 513

8. Debt

Commercial Paper

During the first six months of 2010, Devon repaid $1.4 billion of commercial paper borrowings primarily with proceeds received from its Gulf of Mexico property divestitures.

In May 2010, Devon reduced the maximum allowed borrowings under its commercial paper program from $2.85 billion to approximately $2.2 billion. At June 30, 2010, Devon had no outstanding commercial paper borrowings.

$350 Million 7.25% Senior Notes Due October 1, 2011

On June 25, 2010, Devon redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011, primarily with proceeds received from its Gulf of Mexico divestitures. The notes were redeemed for $384 million, which represented 100 percent of the principal amount, a make-whole premium of $28 million and $6 million of accrued and unpaid interest. On the date of redemption, these notes also had an unamortized premium of $9 million. The $28 million make-whole premium and $9 million amortization of the remaining premium are included in interest expense in the accompanying 2010 consolidated statements of operations.

Non-Interest Bearing Promissory Note

On June 29, 2010, Devon issued a four-year $155 million Canadian dollar non-interest bearing promissory note in connection with the formation of the Pike oil sands joint venture described in Note 5. The present value of the note was $139 million on the issue date based upon an effective interest rate of 3.125%. Of the $139 million, $53 million is presented as

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

short-term debt and the remainder is presented as long-term debt in the accompanying June 30, 2010, consolidated balance sheet.

Credit Lines

In the second quarter of 2010, Devon cancelled its $700 million Short-Term Facility prior to its November 2, 2010 maturity date. Devon incurred no cost to cancel the facility and will avoid paying the facility fee that pertains to the cancellation period.

Devon has a syndicated, unsecured revolving line of credit that can be accessed to provide liquidity as needed. The following schedule summarizes the capacity of Devon s Senior Credit Facility by maturity date, as well as its available capacity as of June 30, 2010 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Less:	
Outstanding Senior Credit Facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	85
Total available capacity	$ 2,565

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%. 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 June 30, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at June 30, 2010, as calculated pursuant to the terms of the agreement, was 16.1%.

Interest Expense

The following schedule includes the components of interest expense.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Interest based on debt outstanding	$ 104	$ 110	$ 209	$ 218
Capitalized interest	(14)	(22)	(35)	(49)
Early retirement of debt	19		19	
Other	2	2	4	4
Total	$ 111	$ 90	$ 197	$ 173

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

9. Asset Retirement Obligations

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,513	$ 1,387
Liabilities incurred	25	43
Liabilities settled	(71)	(43)
Revision of estimated obligation	194	22
Liabilities assumed by others	(256)	
Accretion expense on discounted obligation	50	46
Foreign currency translation adjustment	(14)	30
Asset retirement obligations as of end of period	1,441	1,485
Less current portion	95	175
Asset retirement obligations, long-term	$ 1,346	$ 1,310

During the first six months of 2010 and 2009, Devon recognized revisions to its asset retirement obligations totaling $194 million and $22 million, respectively. The primary factors causing the 2010 and 2009 increases were an overall increase in abandonment cost estimates and a decrease in the discount rate used to present value the obligations.

During the first six months of 2010, Devon reduced its asset retirement obligations by $256 million for those obligations that were assumed by purchasers of Devon s Gulf of Mexico oil and gas properties.

10. Retirement Plans

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

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009	2010	2009
	(In millions)							
Net periodic benefit cost:								
Service cost	$ 8	$ 11	$ 16	$ 22	$	$	$	$
Interest cost	14	14	28	28	1	1	2	2
Expected return on plan assets	(9)	(9)	(18)	(18)				
Amortization of prior service cost	1	1	2	2				
Net actuarial loss	7	11	14	22				
	$ 21	$ 28	$ 42	$ 56	$ 1	$ 1	$ 2	$ 2

Net periodic benefit
cost

11. Stockholders Equity

Stock Repurchases

During the second quarter of 2010, Devon repurchased 7.6 million common shares under its $3.5 billion stock repurchase program for $495 million, or $65.07 per share. This program expires December 31, 2011.

Dividends

Devon paid common stock dividends of $142 million (quarterly rates of $0.16 per share) in the first six months of 2010 and 2009, respectively.

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

12. 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 that 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. However, 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 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 as of the date of this report, neither Devon nor its property is subject to any material pending legal proceedings.

Commitments

At the end of 2009, Devon s commitments included $0.9 billion that related to long-term lease contracts for two deepwater drilling rigs being used in the Gulf of Mexico. As discussed in Note 5, Devon no longer has lease commitments for these two rigs.

At the end of 2009, Devon s commitments also included $0.5 billion that related to a long-term lease contract for a deepwater drilling rig being used in Brazil. Devon s lease and remaining commitments for this rig will be assumed by the buyer of Devon s assets in Brazil when the associated divestiture transaction closes.

At the end of 2009, Devon s commitments also included $0.4 billion that related to leases of floating, production, storage and offloading facilities being used in the Gulf of Mexico, Brazil and China. Devon s commitments for the Gulf of Mexico and China leases were assumed by the purchasers in the first half of 2010. The Brazil lease will be assumed by the buyer when the associated divestiture transaction closes.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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13. Fair Value Measurements

The following tables provide carrying value and fair value measurement information for Devon s financial assets and liabilities.

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(In millions)		
June 30, 2010 assets (liabilities):					
Gas price swaps	$ 327	$ 327	$	$ 327	$
Gas price collars	$ 19	$ 19	$	$ 19	$
Gas basis swaps	$ 15	$ 15	$	$ 15	$
Oil price collars	$ 90	$ 90	$	$ 90	$
Interest rate swaps	$ 84	$ 84	$	$ 84	$
Debt	$(5,624)	$(6,556)	$	$(6,417)	$ (139)
Long-term investments	$ 97	$ 97	$	$	$ 97
December 31, 2009 assets (liabilities):					
Gas price swaps	$ 169	$ 169	$	$ 169	$
Gas basis swaps	$ 3	$ 3	$	$ 3	$
Oil price collars	$ (38)	$ (38)	$	$ (38)	$
Interest rate swaps	$ 170	$ 170	$	$ 170	$
Debt	$(7,279)	$(8,214)	$(1,432)	$(6,782)	$
Long-term investments	$ 115	$ 115	$	$	$ 115

Devon s Level 3 fair value measurements included in the table above relate to a non-interest bearing promissory note and certain long-term investments. As discussed in Note 8, Devon issued a non-interest bearing promissory note that was recorded at its estimated present value of $139 million on the June 29, 2010 issue date. As a result, Devon s Level 3 measurements for debt increased $139 million during the first six months of 2010. The changes in the Level 3 measurements for long-term investments during the first six months of 2010 and 2009 resulted entirely of redemptions of principal.

14. Restructuring Costs

In the fourth quarter of 2009, Devon recognized $153 million of estimated employee severance costs associated with the planned divestiture of its offshore assets that was announced in November 2009. This amount was based on estimates of the number of employees that will ultimately be impacted by the divestitures and included amounts related to cash severance costs and accelerated vesting of share-based grants. Of the $153 million total, $105 million related to Devon s U.S. Offshore operations and the remainder related to its International discontinued operations.

As discussed in Note 5, Devon had divested all its U.S. Offshore assets by the end of the second quarter of 2010. As a result of these divestitures and associated employee terminations, Devon decreased its estimate of employee severance costs in the second quarter of 2010 by $14 million. As a result, Devon now estimates it will incur approximately $139 million of employee severance costs. The lower estimate results primarily from more offshore employees than previously estimated receiving comparable positions with the purchaser of the properties or in Devon s U.S. Onshore operations. Of the $139 million total, $95 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations. Of the $14 million reduction recognized in the second quarter of 2010, $9 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations.

All cash severance and accelerated vesting of share-based grants are included in restructuring costs in the accompanying 2010 consolidated statements of operations. Amounts related to cash severance costs are accrued for in other current liabilities in the accompanying consolidated balance sheets while amounts related to accelerated share-based awards are recorded as a reduction to Devon s additional paid-in capital in the accompanying consolidated balance sheets.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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The schedule below summarizes activity and liability balances associated with Devon s restructuring liability included in other current liabilities.

	Continuing Operations	Discontinued Operations (In millions)	Total
Balance as of December 31, 2009	$ 61	$ 23	$ 84
Cash payments	(5)	(1)	(6)
Revision of estimate	(5)	(3)	(8)
Balance as of June 30, 2010	$ 51	$ 19	$ 70

The schedule below summarizes the components of restructuring costs in the accompanying consolidated statements of operations for the second quarter and first six months of 2010.

	Continuing Operations	Discontinued Operations (In millions)	Total
Revision to estimate cash severance	$ (5)	$ (3)	$ (8)
Revision to estimate acceleration of share-based awards	(4)	(2)	(6)
Other	1		1
Restructuring costs	$ (8)	$ (5)	$ (13)

15. Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, Devon reduced the carrying value of its United States oil and gas properties $6,408 million, or $4,085 million after taxes, due to a full cost ceiling limitation. The reduction resulted from a significant decrease in the full cost ceiling compared to the immediately preceding quarter due to the effects of declining natural gas prices subsequent to December 31, 2008.

16. Discontinued Operations

Revenues related to Devon s discontinued operations totaled $222 million and $434 million in the second quarter and first six months of 2010, respectively, and $268 million and $396 million in the second quarter and first six months of 2009, respectively.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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The following table presents the main classes of assets and liabilities associated with Devon s discontinued operations.

	June 30, 2010	December 31, 2009
	(In millions)	
Cash and cash equivalents	$ 742	$ 365
Accounts receivable	125	165
Other current assets	153	127
Current assets	$ 1,020	$ 657
Property and equipment, net	$ 1,203	$ 1,099
Goodwill	68	68
Other long-term assets	69	83
Total long-term assets	$ 1,340	$ 1,250
Accounts payable	$ 358	$ 158
Other current liabilities	190	76
Current liabilities	$ 548	$ 234
Asset retirement obligations	$ 100	$ 109
Deferred income taxes	85	101
Other liabilities	4	3
Long-term liabilities	$ 189	$ 213

Reductions of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, Devon reduced the carrying values of its Brazilian and other International oil and gas properties, which are now held for sale, $109 million due to full cost ceiling limitations. The Brazilian reduction of $103 million, which had no related tax benefit, resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, Devon concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

Divestiture

See Note 5 for more information on the divestiture of Devon s Panyu operations in China.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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17. Earnings (Loss) Per Share

The following table reconciles earnings (loss) from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings (loss) per share for the three-month and six-month periods ended June 30, 2010 and 2009. Because a net loss from continuing operations was generated during the six-month period ended June 30, 2009, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share from continuing operations in the six months ended June 30, 2009 reported in the accompanying 2009 consolidated statement of operations is the same as the basic loss per share amount.

	Earnings (Loss)	Common Shares	Earnings (Loss) per Share
	(In millions, except per share amounts)		
Three Months Ended June 30, 2010:			
Earnings from continuing operations	$ 352	445	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	348	440	$ 0.79
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		1	
Diluted earnings per share	$ 348	441	$ 0.79
Three Months Ended June 30, 2009:			
Earnings from continuing operations	$ 190	444	
Attributable to participating securities	(3)	(5)	
Basic earnings per share	187	439	$ 0.43
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 187	441	$ 0.42
Six Months Ended June 30, 2010:			
Earnings from continuing operations	$ 1,426	446	
Attributable to participating securities	(17)	(5)	
Basic earnings per share	1,409	441	$ 3.20
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		1	
Diluted earnings per share	$ 1,409	442	$ 3.19

Six Months Ended June 30, 2009:			
Loss from continuing operations	$ (3,692)	444	
Attributable to participating securities	44	(5)	
Basic and diluted loss per share	$ (3,648)	439	$ (8.32)

Certain options to purchase shares of Devon s common stock are excluded from the dilution calculations because the options are antidilutive. During the three-month and six-month periods ended June 30, 2010, 7.9 million shares and 6.4 million shares, respectively, were excluded from the diluted earnings per share calculations. During the three-month and six-month periods ended June 30, 2009, 7.1 million shares and 8.9 million shares, respectively, were excluded from the diluted earnings per share calculations.

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

18. Segment Information

Devon manages its 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 business. However, Devon s Canadian and International divisions are reported as separate reporting segments primarily due to significant differences in the respective regulatory environments.

Following is certain financial information regarding Devon s reporting segments. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
		(In millions)		
As of June 30, 2010:				
Current assets	$ 3,468	$ 561	$ 1,020	$ 5,049
Property and equipment, net	10,478	6,363		16,841
Goodwill	3,046	2,846		5,892
Other assets	511	338	1,340	2,189
Total assets	$ 17,503	$ 10,108	$ 2,360	$ 29,971
Current liabilities	$ 2,178	$ 676	$ 548	$ 3,402
Long-term debt	2,503	3,068		5,571
Asset retirement obligations	550	796		1,346
Other liabilities	874	45	189	1,108
Deferred income taxes	591	1,123		1,714
Stockholders equity	10,807	4,400	1,623	16,830
Total liabilities and stockholders equity	$ 17,503	$ 10,108	$ 2,360	$ 29,971

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

	U.S.	Canada	Total
		(In millions)	
Three Months Ended June 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,144	$ 638	$ 1,782
Oil and gas derivatives	32	13	45
Marketing and midstream revenues	372	33	405
Total revenues	1,548	684	2,232
Expenses and other, net:			
Lease operating expenses	243	199	442
Taxes other than income taxes	83	9	92
Marketing and midstream operating costs and expenses	252	28	280
Depreciation, depletion and amortization of oil and gas properties	248	178	426
Depreciation and amortization of non-oil and gas properties	57	6	63
Accretion of asset retirement obligations	12	12	24
General and administrative expenses	98	32	130
Restructuring costs	(8)		(8)
Interest expense	55	56	111
Non-oil and gas financial instruments	81		81
Other, net	(26)	4	(22)
Total expenses and other, net	1,095	524	1,619
Earnings from continuing operations before income taxes	453	160	613
Income tax expense (benefit):			
Current	631	76	707
Deferred	(421)	(25)	(446)
Total income tax expense	210	51	261
Earnings from continuing operations	$ 243	$ 109	$ 352
Capital expenditures, continuing operations	$ 1,145	$ 774	$ 1,919

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

	U.S.	Canada (In millions)	Total
Three Months Ended June 30, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 907	$ 543	$ 1,450
Oil and gas derivatives	13		13
Marketing and midstream revenues	351	8	359
Total revenues	1,271	551	1,822
Expenses and other, net:			
Lease operating expenses	252	158	410
Taxes other than income taxes	70	9	79
Marketing and midstream operating costs and expenses	226	4	230
Depreciation, depletion and amortization of oil and gas properties	274	156	430
Depreciation and amortization of non-oil and gas properties	67	7	74
Accretion of asset retirement obligations	14	9	23
General and administrative expenses	141	32	173
Interest expense	34	56	90
Non-oil and gas financial instruments	(10)		(10)
Other, net	18	6	24
Total expenses and other, net	1,086	437	1,523
Earnings from continuing operations before income taxes	185	114	299
Income tax expense (benefit):			
Current	14	44	58
Deferred	55	(4)	51
Total income tax expense	69	40	109
Earnings from continuing operations	$ 116	$ 74	$ 190
Capital expenditures, continuing operations	$ 757	$ 185	$ 942

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

	U.S.	Canada (In millions)	Total
Six Months Ended June 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 2,514	$ 1,338	$ 3,852
Oil and gas derivatives	657	8	665
Marketing and midstream revenues	868	67	935
Total revenues	4,039	1,413	5,452
Expenses and other, net:			
Lease operating expenses	467	389	856
Taxes other than income taxes	173	20	193
Marketing and midstream operating costs and expenses	621	56	677
Depreciation, depletion and amortization of oil and gas properties	509	343	852
Depreciation and amortization of non-oil and gas properties	113	13	126
Accretion of asset retirement obligations	25	25	50
General and administrative expenses	206	62	268
Restructuring costs	(8)		(8)
Interest expense	85	112	197
Non-oil and gas financial instruments	66		66
Other, net	(29)	3	(26)
Total expenses and other, net	2,228	1,023	3,251
Earnings from continuing operations before income taxes	1,811	390	2,201
Income tax expense (benefit):			
Current	845	161	1,006
Deferred	(186)	(45)	(231)
Total income tax expense	659	116	775
Earnings from continuing operations	$ 1,152	$ 274	$ 1,426
Capital expenditures, before revision of future asset retirement obligations	$ 2,189	$ 1,144	$ 3,333
Revision of future asset retirement obligations	72	122	194
Capital expenditures, continuing operations	$ 2,261	$ 1,266	$ 3,527

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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	U.S.	Canada (In millions)	Total
Six Months Ended June 30, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 1,845	$ 980	$ 2,825
Oil and gas derivatives	167		167
Marketing and midstream revenues	715	15	730
Total revenues	2,727	995	3,722
Expenses and other, net:			
Lease operating expenses	522	328	850
Taxes other than income taxes	151	17	168
Marketing and midstream operating costs and expenses	446	8	454
Depreciation, depletion and amortization of oil and gas properties	714	276	990
Depreciation and amortization of non-oil and gas properties	131	13	144
Accretion of asset retirement obligations	28	18	46
General and administrative expenses	276	60	336
Interest expense	61	112	173
Non-oil and gas financial instruments	(15)		(15)
Reduction of carrying value of oil and gas properties	6,408		6,408
Other, net	15	16	31
Total expenses and other, net	8,737	848	9,585
Earnings (loss) from continuing operations before income taxes	(6,010)	147	(5,863)
Income tax expense (benefit):			
Current	4	46	50
Deferred	(2,224)	3	(2,221)
Total income tax expense (benefit)	(2,220)	49	(2,171)
Earnings (loss) from continuing operations	$ (3,790)	$ 98	$ (3,692)
Capital expenditures, before revision of future asset retirement obligations	$ 1,902	$ 486	$ 2,388
Revision of future asset retirement obligations	37	(15)	22
Capital expenditures, continuing operations	$ 1,939	$ 471	$ 2,410

19. Supplemental Information to Statements of Cash Flows

Information related to Devon s cash flows is presented below.

Six Months

	Ended June 30, 2010	2009
	(In millions)	
Net decrease in working capital:		
(Increase) decrease in accounts receivable	$ (1)	$ 176
Decrease in other current assets	44	173
Decrease in accounts payable	(21)	(72)
Decrease in revenues and royalties due to others	(21)	(113)
Increase (decrease) in other current liabilities	580	(112)
Net decrease in working capital	$ 581	$ 52
Supplementary cash flow data continuing and discontinued operations:		
Interest paid net of capitalized interest	$ 202	$ 138
Income taxes paid (received)	$ 306	$ (139)

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

The following discussion addresses material changes in our results of operations and capital resources and uses for the three-month and six-month periods ended June 30, 2010, compared to the three-month and six-month periods ended June 30, 2009, and in our financial condition and liquidity since December 31, 2009. For information regarding our critical accounting policies and estimates, see our 2009 Annual Report on Form 10-K under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

Business Overview

During the second quarter and first six months of 2010, we generated net earnings of $706 million, or $1.58 per diluted share, and $1.9 billion, or $4.24 per diluted share, for the respective periods. This compares to net earnings of $314 million, or $0.70 per diluted share, for the second quarter of 2009 and a net loss of $3.6 billion, or $8.21 per diluted share for the first half of 2009. Our financial results for the first half of 2009 were negatively impacted by a $6.4 billion ($4.1 billion after tax) reduction of the carrying value of our United States oil and gas properties.

Key measures of our performance for the second quarter and first six months of 2010 compared to 2009 are summarized below:

- The combined realized price without hedges for oil, gas and NGLs increased 27% and 42% in the second quarter and first six months of 2010, respectively.

- Oil and gas derivatives generated net gains of $45 million and $665 million in the second quarter and first six months of 2010, respectively, and net gains of $13 million and $167 million in the second quarter and first six months of 2009. Included in these amounts were cash receipts of $252 million and $348 million for the second quarter and first six months of 2010, respectively, and cash receipts of $114 million and $232 million in the second quarter and first six months of 2009, respectively.

- Operating cash flow increased 39% to $2.9 billion in the first half of 2010.

- Production decreased 3% and 4% in the second quarter and first six months of 2010, respectively.

- Per unit operating costs increased 12% to $7.56 per Boe and 5% to $7.49 per Boe in the second quarter and first six months of 2010, respectively.

- Marketing and midstream operating profit decreased 3% to $125 million and 6% to $258 in the second quarter and first six months of 2010, respectively.

- Cash spent on capital expenditures was approximately $3.2 billion in the first six months of 2010.

Additionally, we have made significant progress toward completion of our offshore divestiture program. In the second quarter of 2010, we completed our exit from the Gulf of Mexico and divested our Panyu operations in China. During the first six months of 2010, our divestitures generated total after-tax proceeds of $3.6 billion. In accordance with full cost accounting rules, we did not recognize a gain on the Gulf of Mexico divestitures. We recognized a $235 million after-tax gain on the Panyu divestiture.

Additionally, we have entered into agreements to sell our Azerbaijan and Brazil assets for $5.2 billion. We have received the necessary government approvals for the Azerbaijan transaction, which is now scheduled to close on August 16, 2010. The Brazil transaction continues to progress through the approval process of the Brazilian government and is on track to close around the end of 2010. We have also entered into an agreement to sell our remaining assets in China for $0.1 billion.

Furthermore, in connection with the completed divestitures, we have substantially reduced our deepwater drilling rig commitments. We no longer have lease commitments for the two deepwater drilling rigs that were being used in the Gulf of Mexico. The third deepwater drilling rig is being used in our Brazil operations and will be assumed by the buyer when that divestiture transaction closes.

The divestiture process is ongoing for our exploration assets in Angola and other minor International assets. Once all divestiture assets are sold, we estimate the total pre-tax proceeds will approximate $10 billion and the after-tax proceeds will be approximately $8 billion. As a result of the success we have experienced with our offshore divestiture program, we are using the divestiture proceeds to invest in North America Onshore exploration and development opportunities, repurchase our common shares and reduce outstanding debt.

In conjunction with certain offshore divestitures in the second quarter of 2010, we formed a heavy oil joint venture to operate and develop the Pike oil sands leases in Alberta, Canada. As a result, we acquired a 50 percent interest in the Pike oil sands leases for $500 million. We will also fund $155 million of Canadian dollar capital costs on behalf of our joint-venture partner. The majority of these costs are expected to be paid during 2011 and 2012.

In May 2010, we announced a share repurchase program that authorizes the repurchase of up to $3.5 billion of our common shares. During the second quarter of 2010, we repurchased 7.6 million shares for $495 million, or $65.07 per share. We repaid all our outstanding commercial paper and redeemed our $350 million 7.25% senior notes prior to their scheduled maturity with proceeds from the U.S. Offshore divestitures.

Additionally, our performance and divestitures to date enabled us to end the second quarter of 2010 with a robust level of liquidity. As of June 30, 2010, we held $2.9 billion in cash and had $2.6 billion of available credit under our credit lines. This liquidity will allow us to continue repurchasing common shares and investing in the opportunities that exist across our North America Onshore portfolio of properties.

Results of Operations

Revenues

Our oil, gas and NGL production volumes are shown in the following table.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	**2009**	**Change(2)**	**2010**	**2009**	**Change(2)**
Oil (MMBbls)						
U.S. Onshore	3	3	+14%	6	6	+7%
Canada	6	6	+3%	13	13	+2%
North America Onshore	9	9	+6%	19	19	+3%
U.S. Offshore	1	1	-37%	2	2	-16%
Total	10	10	+1%	21	21	+1%
Gas (Bcf)						
U.S. Onshore	173	183	-5%	339	364	-7%
Canada	58	60	-5%	108	113	-4%
North America Onshore	231	243	-5%	447	477	-6%
U.S. Offshore	7	11	-34%	17	22	-21%
Total	238	254	-6%	464	499	-7%
NGLs (MMBbls)						
U.S. Onshore	7	7	+8%	14	13	+7%
Canada	1	1	-7%	2	2	-7%
North America Onshore	8	8	+6%	16	15	+5%
U.S. Offshore			-16%			-18%
Total	8	8	+6%	16	15	+4%
Total (MMBoe) (1)						
U.S. Onshore	39	39	-2%	76	79	-4%

Canada	17	18	-2%	33	34	-2%
North America Onshore	56	57	-2%	109	113	-3%
U.S. Offshore	2	3	-34%	5	6	-19%
Total	58	60	-3%	114	119	-4%

(1) Gas volumes are converted to Boe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to Boe on a one-to-one basis with oil.

(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in the table.

The following table presents the prices we realized on our production volumes. These prices exclude any effects due to our oil and gas derivatives.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change	2010	2009	Change
Oil (per Bbl)						
U.S. Onshore	$74.65	$54.66	+37%	$74.73	$44.67	+67%
Canada	$54.43	$48.14	+13%	$58.36	$38.19	+53%
North America Onshore	$61.11	$50.14	+22%	$63.67	$40.22	+58%
U.S. Offshore	$79.09	$56.44	+40%	$77.81	$49.69	+57%
Total	$62.35	$50.84	+23%	$64.93	$41.24	+57%
Gas (per Mcf)						
U.S. Onshore	$ 3.47	$ 2.75	+26%	$ 4.05	$ 3.09	+31%
Canada	$ 3.99	$ 3.25	+23%	$ 4.50	$ 3.82	+18%
North America Onshore	$ 3.60	$ 2.87	+25%	$ 4.16	$ 3.26	+28%
U.S. Offshore	$ 4.39	$ 3.76	+17%	$ 5.12	$ 4.46	+15%
Total	$ 3.62	$ 2.91	+24%	$ 4.19	$ 3.31	+27%
NGLs (per Bbl)						
U.S. Onshore	$28.73	$20.81	+38%	$31.39	$19.16	+64%
Canada	$46.18	$30.99	+49%	$47.52	$28.52	+67%
North America Onshore	$30.81	$22.20	+39%	$33.31	$20.41	+63%
U.S. Offshore	$35.59	$23.69	+50%	$38.22	$21.96	+74%
Total	$30.90	$22.24	+39%	$33.41	$20.45	+63%
Combined (per Boe) (1)						
U.S. Onshore	$26.77	$19.98	+34%	$29.71	$20.57	+44%
Canada	$37.08	$30.85	+20%	$40.62	$29.11	+40%
North America Onshore	$29.92	$23.31	+28%	$33.00	$23.12	+43%
U.S. Offshore	$46.17	$35.49	+30%	$49.06	$34.85	+41%
Total	$30.49	$23.93	+27%	$33.70	$23.73	+42%

(1) Gas volumes are converted to Boe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to

Boe on a
one-to-one basis
with oil.

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 June 30, 2010 and 2009.

	Oil	Gas	NGLs	Total
		(In millions)		
2009 sales	$ 541	$ 739	$ 170	$ 1,450
Changes due to volumes	8	(47)	9	(30)
Changes due to prices	124	169	69	362
2010 sales	$ 673	$ 861	$ 248	$ 1,782

The volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales between the six months ended June 30, 2010 and 2009.

	Oil	Gas	NGLs	Total
		(In millions)		
2009 sales	$ 868	$ 1,651	$ 306	$ 2,825
Changes due to volumes	10	(113)	14	(89)
Changes due to prices	505	409	202	1,116
2010 sales	$ 1,383	$ 1,947	$ 522	$ 3,852

Oil Sales

Oil sales increased $124 million in the second quarter of 2010 as a result of a 23% 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 price. The higher differential resulted primarily from the increase in our heavy oil production and the widening of the associated differential related to our Canadian operations.

Oil sales increased $8 million in the second quarter of 2010 due to a one percent increase in production. The increase was comprised of the net effects of a 6% increase in our North America Onshore production and a 37% decrease in our U.S. Offshore production. The increased North America Onshore production resulted primarily from the continued development activities at our Jackfish operations in Canada. The decrease in our U.S. Offshore production was primarily due to the divestiture of these properties in the second quarter of 2010.

Oil sales increased $505 million in the first half of 2010 as a result of a 57% 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.

Oil sales increased $10 million in the first half of 2010 due to a one percent increase in production. The increase was comprised of the net effects of a 3% increase in our North America Onshore production and a 16% decrease in our U.S. Offshore production. The increased North America Onshore production resulted primarily from the continued development activities at our Jackfish operations in Canada. The decrease in our U.S. Offshore production was primarily due to the divestiture of these properties in the second quarter of 2010.

Gas Sales

Gas sales increased $169 million during the second quarter of 2010 as a result of a 24% increase in our realized price without hedges. This increase was largely due to increases in the North American regional index prices upon which our gas sales are based.

A 16 Bcf decrease in production during the second quarter of 2010 caused gas sales to decrease by $47 million. The decrease in production was primarily due to reduced drilling during most of 2009 for our North America Onshore properties. As a result of the reduced drilling in response to lower gas prices, natural declines of existing wells outpaced production gains from new drilling. Also, the divestiture of our U.S. Offshore properties in the second quarter of 2010 contributed four Bcf to the decrease.

Gas sales increased $409 million during the first half of 2010 as a result of a 27% increase in our realized price without hedges. This increase is largely due to increases in the North American regional index prices upon which our gas sales are based.

A 35 Bcf decrease in production during the first half of 2010 caused gas sales to decrease by $113 million. The decrease in production was primarily due to reduced drilling during most of 2009 for our North America Onshore properties. As a result of the reduced drilling in response to lower gas prices, natural declines of existing wells outpaced production gains from new drilling. Also, the divestiture of our U.S. Offshore properties in the second quarter of 2010 contributed four Bcf to the decrease.

NGL Sales

NGL sales increased $69 million during the second quarter of 2010 as a result of a 39% increase in our realized price without hedges. NGL sales increased $202 million during the first half of 2010 as a result of a 63% increase in our realized price without hedges. These increases were largely due to increases in the Mont Belvieu, Texas index price over the same time periods.

Oil and Gas Derivatives

The following tables provide financial information associated with our oil and gas 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Cash settlements receipts (payments):				
Gas price swaps	$ 239	$	$ 337	$
Gas price collars	12	114	13	232
Gas basis swaps	1		(2)	
Total cash settlements	252	114	348	232
Unrealized gains (losses) on fair value changes:				
Gas price swaps	(332)		158	
Gas price collars	(16)	(101)	19	(65)
Gas basis swaps	17		12	
Oil price collars	124		128	
Total unrealized gains (losses) on fair value changes	(207)	(101)	317	(65)
Oil and gas derivatives	$ 45	$ 13	$ 665	$ 167

	Three Months Ended June 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 62.35	$ 3.62	$ 30.90	$ 30.49
Cash settlements of hedges		1.06		4.31
Realized price, including cash settlements	$ 62.35	$ 4.68	$ 30.90	$ 34.80

	Three Months Ended June 30, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 50.84	$ 2.91	$ 22.24	$ 23.93
Cash settlements of hedges		0.45		1.89
Realized price, including cash settlements	$ 50.84	$ 3.36	$ 22.24	$ 25.82

	Six Months Ended June 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 64.93	$ 4.19	$ 33.41	$ 33.70
Cash settlements of hedges		0.75		3.04

Realized price, including cash settlements	$ 64.93	$ 4.94	$ 33.41	$ 36.74

	Six Months Ended June 30, 2009			
	Oil (Per Bbl)	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**Total (Per Boe)**
Realized price without hedges	$ 41.24	$ 3.31	$ 20.45	$ 23.73
Cash settlements of hedges		0.47		1.95
Realized price, including cash settlements	$ 41.24	$ 3.78	$ 20.45	$ 25.68

In 2010, our oil and gas derivatives included gas price swaps, gas basis swaps and oil and gas costless price collars. In 2009, our oil and gas derivatives included only gas price collars. 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. 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 net realized gains related to our price swaps, price collars and basis swaps.

During the second quarter and first half of 2010, we received $252 million, or $1.06 per Mcf, and $348 million, or $0.75 per Mcf, respectively, from counterparties to settle our gas derivatives. During the second quarter and first half of 2009, we received $114 million, or $0.45 per Mcf, and $232 million, or $0.47 per Mcf, respectively, from counterparties to settle our gas derivatives. We had no settlements on oil derivatives in any of these periods.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil and gas derivatives in each reporting period. We estimate the fair values of our oil and gas derivatives primarily by using internal discounted cash flow calculations. From time to time, we 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 derivatives at June 30, 2010, a 10% increase in these forward curves would have decreased the fair value of our gas derivatives by approximately $160 million. A 10% increase in the forward curves associated with our oil derivatives would have decreased the fair value of our oil derivatives by approximately $90 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 volumes subject to oil and gas derivatives is not a variable in our cash flow calculations but does impact the total derivative values.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with thirteen 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 threshold for collateral posting 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 June 30, 2010, the credit ratings of all our counterparties were investment grade.

Including the cash settlements discussed above, the net gains from our oil and gas derivatives were $45 million and $665 million during the second quarter and first half of 2010, respectively. Including the cash settlements discussed above, the net gains from our oil and gas derivatives were $13 million and $167 million during the second quarter and first half of 2009, respectively. In addition to the impact of cash settlements, these net gains 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 and gas derivative positions as of the end of the second quarter of 2010 is included in Item 3. Quantitative and Qualitative Disclosures About Market Risk of this report.

Marketing and Midstream Revenues and Operating Costs and Expenses

The details of the changes in marketing and midstream revenues, operating costs and expenses and the resulting operating profit are shown in the table below.

	Three Months Ended June 30,			**Six Months Ended June 30,**		
	2010	**2009**	**Change(1)**	**2010**	**2009**	**Change(1)**
			($ in millions)			
Marketing and midstream:						
Revenues	$ 405	$ 359	+13%	$ 935	$ 730	+28%
Operating costs and expenses	280	230	+21%	677	454	+49%
Operating profit	$ 125	$ 129	-3%	$ 258	$ 276	-6%

(1) All percentage changes included in this table are based on actual figures and are not calculated using

the rounded figures included in this table.

During the second quarter of 2010, marketing and midstream revenues increased $46 million and operating costs and expenses increased $50 million, causing operating profit to decrease $4 million. During the first half of 2010, marketing and midstream revenues increased $205 million and operating costs and expenses increased $223 million, causing operating profit to decrease $18 million. Revenues, expenses and operating profit increased due to higher natural gas and NGL production and processing prices, partially offset by the effects of lower gas pipeline throughput. However, the increases in operating profit resulting from these factors were more than offset by lower gas margins.

Lease Operating Expenses (LOE)

The details of the changes in LOE are shown in the table below.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change(1)	2010	2009	Change(1)
Lease operating expenses ($ in millions):						
U.S. Onshore	$ 216	$ 212	+2%	$ 407	$ 441	-8%
Canada	199	158	+25%	389	328	+18%
North America Onshore	415	370	+12%	796	769	+3%
U.S. Offshore	27	40	-32%	60	81	-26%
Total	$ 442	$ 410	+8%	$ 856	$ 850	+1%
Lease operating expenses per Boe:						
U.S. Onshore	$ 5.52	$ 5.31	+4%	$ 5.33	$ 5.56	-4%
Canada	$ 11.53	$ 9.00	+28%	$ 11.80	$ 9.75	+21%
North America Onshore	$ 7.36	$ 6.44	+14%	$ 7.28	$ 6.81	+7%
U.S. Offshore	$ 13.18	$ 12.76	+3%	$ 12.00	$ 13.04	-8%
Total	$ 7.56	$ 6.77	+12%	$ 7.49	$ 7.14	+5%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

LOE increased $32 million in the second quarter of 2010, which included a $45 million increase related to our North America Onshore operations and a $13 million decrease related to our U.S. Offshore operations. North America Onshore LOE increased $24 million due to changes in the exchange rate between the U.S. and Canadian dollars. Increased costs related to our Jackfish operations in Canada and higher repairs and maintenance costs across our other North America Onshore properties also caused LOE to increase $27 million. North America Onshore LOE decreased $6 million as a result of our 2% decrease in North America Onshore production. U.S. Offshore LOE decreased primarily due to property divestitures in the second quarter of 2010. Excluding the decrease due to lower production, these factors were also the main contributors to the changes in LOE per Boe.

LOE increased $6 million in the first half of 2010, which included a $27 million increase related to our North America Onshore operations and a $21 million decrease related to our U.S. Offshore operations. North America Onshore LOE increased $56 million due to changes in the exchange rate between the U.S. and Canadian dollars. The 3% decrease in North America Onshore production caused LOE to decline $24 million. North America Onshore LOE decreased $5 million due to lower costs for materials, equipment and personnel, as well as declines in maintenance and well workover projects. U.S. Offshore LOE decreased $21 million primarily due to property divestitures in the second quarter of 2010 and hurricane repair expenses incurred in 2009. The increase due to exchange rates was also the main contributor to the changes in LOE per Boe.

Taxes Other Than Income Taxes

The following table details the changes in our taxes other than income taxes.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	**2009**	**Change(1)**	**2010**	**2009**	**Change(1)**
			($ in millions)			
Production	$ 46	$ 28	+64%	$ 105	$ 60	+74%
Ad valorem	46	49	-7%	86	103	-17%
Other		2	-79%	2	5	-54%
Total	$ 92	$ 79	+17%	$ 193	$ 168	+15%

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

Production taxes increased $18 million and $45 million in the second quarter of 2010 and first half of 2010, respectively, primarily due to an increase in our U.S. Onshore revenues. Ad valorem taxes decreased $3 million and $17 million respectively, primarily due to lower estimated assessed values of our oil and gas property and equipment.

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

The changes in our production volumes, DD&A rate per unit and DD&A of oil and gas properties are shown in the table below.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010	2009	Change(1)	2010	2009	Change(1)
Total production volumes (MMBoe)	58	60	-3%	114	119	-4%
DD&A rate ($ per Boe)	$ 7.28	$ 7.10	+3%	$ 7.45	$ 8.31	-10%
DD&A expense ($ in millions)	$ 426	$ 430	-1%	$ 852	$ 990	-14%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

The following table details the changes in DD&A of oil and gas properties between the three and six months ended June 30, 2010 and 2009.

	Three Months Ended June 30,	Six Months Ended June 30,
	(In millions)	
2009 DD&A	$ 430	$ 990
Change due to volumes	(15)	(40)
Change due to rate	11	(98)
2010 DD&A	$ 426	$ 852

Oil and gas property-related DD&A increased $11 million during the second quarter of 2010 due to a 3% increase in the DD&A rate. Our drilling activities subsequent to the end of the second quarter of 2009 have resulted in proved reserve additions at a cost higher than the second quarter 2009 DD&A rate, causing the rate to increase. In addition, changes in the exchange rate between the U.S. and Canadian dollars increased our rate. These increases were partially offset by the effect of our U.S. Offshore property divestitures in 2010.

Oil and gas property-related DD&A decreased $98 million during the first half of 2010 due to a 10% decrease in the DD&A rate. The largest contributor to the rate decrease was a reduction of the carrying value of our United States oil and gas properties recognized in the first quarter of 2009. This reduction totaled $6.4 billion and resulted from a full cost ceiling limitation. Additionally, our U.S. Offshore property divestitures in 2010 also contributed to the rate decrease. These decreases were partially offset by the effect of changes in the exchange rate between the U.S. and

Canadian dollars, as well as the effect resulting from drilling activities, which both caused the rate to increase.

General and Administrative Expenses (G&A)

The following schedule includes the components of G&A expense.

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Change(1)	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Change(1)
			($ in millions)			
Gross G&A	$ 240	$ 293	-18%	$ 485	$ 581	-16%
Capitalized G&A	(81)	(91)	-11%	(161)	(181)	-11%
Reimbursed G&A	(29)	(29)	+0%	(56)	(64)	-11%
Net G&A	$ 130	$ 173	-25%	$ 268	$ 336	-20%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

Gross G&A decreased $53 million in the second quarter of 2010 compared to the same period in 2009. The largest contributor to the decrease was lower severance costs associated with certain Gulf of Mexico employees that were impacted by the integration of our Gulf of Mexico and International operations into one offshore unit in the second quarter of 2009. Additionally, gross G&A and capitalized G&A decreased due to lower employee compensation and benefits, as well as initiatives to manage spending in certain discretionary cost categories. These decreases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollars.

Gross G&A decreased $96 million in the first half of 2010 compared to the same period in 2009. The largest contributor to the decrease was lower severance costs associated with employee departures and the offshore integration discussed above. In addition, gross G&A and capitalized G&A decreased due to lower employee compensation and benefits, as well as initiatives to manage spending in certain discretionary cost categories. These decreases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollars.

Restructuring Costs

In the fourth quarter of 2009, we recognized $153 million of estimated employee severance costs associated with the planned divestitures of our offshore assets that was announced in November 2009. This amount was based on estimates of the number of employees that will ultimately be impacted by the divestitures and included amounts related to cash severance costs and accelerated vesting of share-based grants. Of the $153 million total, $105 million related to our U.S. Offshore operations and the remainder related to our International discontinued operations.

We had divested all our U.S. Offshore assets by the end of the second quarter of 2010. As a result of these divestitures and associated employee terminations, we decreased our estimate of employee severance costs in the second quarter of 2010 by $14 million. As a result, we now estimate we will incur approximately $139 million of employee severance costs. The lower estimate results primarily from more offshore employees than previously estimated receiving comparable positions with the purchaser of the properties or in our U.S. Onshore operations. Of the $14 million reduction in estimated employee severance costs recognized in the second quarter of 2010, $9 million related to our U.S. Offshore operations and the remainder related to our International discontinued operations. We also incurred other contract termination charges totaling $1 million in the second quarter of 2010 that related to our U.S. Offshore operations.

Interest Expense

The following schedule includes the components of interest expense.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Interest based on debt outstanding	$ 104	$ 110	$ 209	$ 218
Capitalized interest	(14)	(22)	(35)	(49)
Early retirement of debt	19		19	
Other	2	2	4	4
Total	$ 111	$ 90	$ 197	$ 173

Interest based on debt outstanding decreased during the second quarter and first six months of 2010 primarily due to the retirement of $177 million of 10.125% notes upon their maturity in the fourth quarter of 2009.

Capitalized interest decreased during the second quarter and first six months of 2010 primarily due to the divestitures of our U.S. Offshore properties in 2010.

In the second quarter of 2010, we redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011. The notes were redeemed for $384 million, which represented 100 percent of the principal amount, a make-whole premium of $28 million and $6 million of accrued and unpaid interest. On the date of redemption, these notes also had an unamortized premium of $9 million. The $19 million presented in the table above represents the net of the $28 million make-whole premium and $9 million amortization of the remaining premium.

Non-Oil and Gas Financial Instruments

The details of the changes in our non-oil and gas financial instruments, which consisted entirely of interest rate swaps, are shown in the table below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In millions)			
(Gains) losses from interest rate swaps:				
Cash settlements	$ (4)	$ (5)	$ (20)	$ (21)
Unrealized fair value changes	85	(5)	86	6
Total	$ 81	$ (10)	$ 66	$ (15)

During the second quarter and first six months of 2010, we received cash settlements totaling $4 million and $20 million, respectively, from counterparties to settle our interest rate swaps. During the second quarter and first six months of 2009, we received such cash settlements totaling $5 million and $21 million, respectively.

In addition to recognizing cash settlements, we also 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.

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 June 30, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $46 million.

As previously discussed for 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 several counterparties. Our interest rate derivative contracts are held 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 June 30, 2010.

Including the cash settlements discussed above, the net losses from our interest rate swaps were $81 million and $66 million during the second quarter and first half of 2010, respectively. Including the cash settlements discussed above, the net gains from our interest rate swaps were $10 million and $15 million during the second quarter and first half of 2009, respectively. 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 rates and the associated future interest rate yields. A summary of our outstanding interest rate swap positions as of the end of the second quarter of 2010 is included in Item 3. Quantitative and Qualitative Disclosures About Market Risk of this report.

Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, we reduced the carrying value of our United States oil and gas properties by $6.4 billion, or $4.1 billion after taxes, due to a full cost ceiling limitation. The reduction resulted from a significant decrease in the full cost ceiling compared to the immediately preceding quarter due to the effects of declining natural gas prices subsequent to December 31, 2008.

Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Total income tax expense (benefit) (In millions)	$ 261	$ 109	$ 775	$ (2,171)
U.S. statutory income tax rate	35%	35%	35%	(35%)
State income taxes	3%	1%	1%	(1%)
Taxation on Canadian operations	(1%)		(1%)	
U.S. taxes on foreign earnings	8%		2%	
Other	(2%)	1%	(2%)	(1%)
Effective income tax (benefit) rate	43%	37%	35%	(37%)

In the second quarter of 2010, we recognized $52 million of deferred income tax expense related to assumed repatriations of earnings from certain of our foreign subsidiaries whose statutory tax rates are less than the U.S. statutory tax rate.

Earnings from Discontinued Operations

The following table presents the components of our earnings from discontinued operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Total production (MMBoe)	3	5	6	8
Combined price without hedges (per Boe)	$ 74.45	$ 55.71	$ 73.56	$ 49.76
		(In millions)		
Operating revenues	$ 222	$ 268	$ 434	$ 396
Expenses and other, net:				
Operating expenses	51	146	129	232
Reduction of carrying value of oil and gas properties				109
Gain on sale of oil and gas properties	(308)		(308)	
Other, net	6	(21)	3	(22)
Total expenses and other, net	(251)	125	(176)	319
Earnings before income taxes	473	143	610	77
Income tax expense	119	19	138	30
Earnings from discontinued operations	$ 354	$ 124	$ 472	$ 47

Earnings increased $230 million in the second quarter of 2010 primarily as a result of the $308 million gain ($235 million after taxes), resulting from the divestiture of our Panyu operations in China.

Earnings increased $425 million in the first six months of 2010 primarily as a result of the $308 million gain ($235 million after taxes), resulting from the divestiture of our Panyu operations in China. Also, earnings increased $109 million due to the 2009 reductions of the carrying value of our oil and gas properties, which primarily related to Brazil. The Brazilian reduction resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, we concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

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

	Six Months Ended June 30,	
	2010	**2009**
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 2,619	$ 1,923
Divestitures of property and equipment	4,129	2
Cash distributed from discontinued operations	450	6
Redemptions of long-term investments	18	4
Stock option exercises	15	9
Commercial paper borrowings		1,330
Debt issuance, net of commercial paper repayments		182
Other	6	5
Total sources of cash and cash equivalents	**7,237**	**3,461**
Uses of cash and cash equivalents:		
Capital expenditures	(3,221)	(2,945)
Commercial paper repayments	(1,432)	
Repurchases of common stock	(430)	
Debt repayments	(350)	(1)
Dividends	(142)	(142)
Total uses of cash and cash equivalents	**(5,575)**	**(3,088)**
Increase from continuing operations	1,662	373
Increase (decrease) from discontinued operations, net of distributions to continuing operations	252	(106)
Effect of foreign exchange rates	(9)	5
Net increase in cash and cash equivalents	**$ 1,905**	**$ 272**
Cash and cash equivalents at end of period	**$ 2,916**	**$ 656**

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 six months of 2010. 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. Our operating cash flow increased approximately 36% in 2010 primarily due to the increase in revenues as discussed in the Results of Operations section of this report.

During the first six months of 2010, our operating cash flow funded approximately 81% of our cash payments for capital expenditures. However, our capital expenditures for the first half of 2010 included $500 million that Devon paid to form a heavy oil joint venture and acquire a 50 percent interest in the Pike oil sands in Alberta, Canada. This acquisition was completed in connection with offshore divestitures discussed below. Excluding this $500 million acquisition, our operating cash flow funded substantially all our capital expenditures during the first half of 2010.

During the first six months of 2009, our operating cash flow funded approximately 65% of our cash payments for capital expenditures. Commercial paper and other borrowings were used to fund the remainder of our cash-based 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 senior credit facility 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.

During the first half of 2010, we completed the divestiture of all our U.S. Offshore properties and our Panyu operations in China, generating $4.6 billion in pre-tax proceeds, net of closing adjustments, or $3.6 billion after taxes. We have used proceeds from these divestitures to repay all our commercial paper borrowings, retire $350 million of other debt that was to mature in October 2011 and begin repurchasing our common shares. In addition, we began redeploying proceeds into our North America Onshore properties, including the $500 million Pike oil sands acquisition mentioned above.

In January 2009, we issued $500 million of 5.625% senior unsecured notes due January 15, 2014 and $700 million of 6.30% senior unsecured notes due January 15, 2019. The net proceeds received of $1.187 billion, after discounts and issuance costs, were used primarily to repay Devon s $1.0 billion of outstanding commercial paper as of December 31, 2008. Subsequent to the $1.0 billion commercial paper repayment in January 2009, we utilized additional commercial paper borrowings of $1.3 billion to fund capital expenditures.

Capital Expenditures

Our capital expenditures are presented by geographic area and type in the following table. The amounts in the table below reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred in prior quarters. Capital expenditures actually incurred during the first half of 2010 and 2009 were approximately $3.3 billion and $2.4 billion, respectively.

	Six Months Ended June 30,	
	2010	**2009**
	(In millions)	
U.S. Onshore	$ 1,468	$ 1,642
Canada	1,202	562
North America Onshore	2,670	2,204
U.S. Offshore	287	505
Total exploration and development	2,957	2,709
Midstream	108	181
Other	156	55
Total continuing operations	$ 3,221	$ 2,945

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 or development of oil and gas properties, which totaled $3.0 billion and $2.7 billion in the first six months of 2010 and 2009, respectively. The increase in exploration and development capital spending in the first six months of 2010 was primarily due to the $500 million Pike oil sands acquisition mentioned above. Partially offsetting this increase was the effect of reduced drilling activities during 2009 across our North America operations in response to declining commodity prices. However, with rising oil prices and proceeds from our offshore divestiture program, we are increasing drilling to grow production across our North America Onshore portfolio of properties.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas gathering and pipeline systems and oil pipelines. Our midstream capital expenditures in 2010 were largely impacted by reduced U.S. Onshore oil and gas drilling activities.

Capital expenditures related to corporate activities increased in 2010. This increase is largely driven by the construction of our new headquarters in Oklahoma City.

Net Repayments of Debt

During the first six months of 2010, we repaid $1.4 billion of commercial paper borrowings and redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011, primarily with proceeds received from our U.S. Offshore divestitures.

Repurchases of Common Stock

During the second quarter of 2010, we began repurchasing shares under our $3.5 billion stock repurchase program announced in May 2010. Including unsettled shares, we repurchased 7.6 million common shares for $495 million, or $65.07 per share.

Dividends

Our common stock dividends were $142 million (quarterly rates of $0.16 per share) in the first six months of 2010 and 2009, respectively.

Liquidity

Our primary source of capital and liquidity has historically been our 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. We estimate these capital resources and the divestiture proceeds discussed below will provide sufficient liquidity to fund our planned uses of capital. The following sections discuss changes to our liquidity subsequent to filing our 2009 Annual Report on Form 10-K.

Operating Cash Flow

Our operating cash flow increased approximately 39% to $2.9 billion in the first six months of 2010. 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, natural gas and NGLs produced. To mitigate some of the risk inherent in prices, we have utilized various price collars related to a portion of our oil and gas production. We have also utilized various price swap contracts and fixed-price physical delivery contracts related to a portion of our future natural gas production. As of June 30, 2010, approximately 58% of our estimated 2010 gas production and 70% of our estimated oil production are subject to either price collars, swaps or fixed-price contracts.

Offshore Divestitures

During 2010, another major source of liquidity are proceeds generated from divestitures of our offshore assets. In the second quarter of 2010, we completed our exit from the Gulf of Mexico and divested our Panyu operations in China, generating total after-tax proceeds of $3.6 billion. Additionally, we have entered into agreements to sell our Azerbaijan and Brazil assets for $5.2 billion. We have received the necessary government approvals for the Azerbaijan transaction, which is now scheduled to close on August 16, 2010. The Brazil transaction continues to progress through the approval process of the Brazilian government and is on track to close around the end of 2010. We have also entered into an agreement to sell our remaining assets in China for $0.1 billion.

Furthermore, in connection with the divestitures, we have substantially reduced our deepwater drilling rig commitments. We no longer have lease commitments for the two deepwater drilling rigs that were being used in the Gulf of Mexico. The third deepwater drilling rig is being used in our Brazil operations and will be assumed by the buyer when that divestiture transaction closes.

The divestiture process is ongoing for our exploration assets in Angola and other minor International assets. Once all divestiture assets are sold, we estimate the total pre-tax proceeds will approximate $10 billion and the after-tax proceeds will be approximately $8 billion. As a result of the success we have experienced with our offshore divestiture program, we are using the divestiture proceeds to invest in North America Onshore exploration and development opportunities, repurchase our common shares and reduce outstanding debt.

Credit Availability

In May 2010, we cancelled our Short-Term Credit Facility prior to its November 2, 2010 maturity date. We incurred no cost to cancel the facility and will avoid paying the facility fee that pertains to the cancellation period.

As of July 30, 2010, we had $2.6 billion of available capacity under our syndicated, unsecured credit facilities that can be used to supplement our operating cash flow and cash on hand to fund our capital expenditures and other commitments. The following schedule summarizes the capacity of our credit facilities by maturity date, as well as our available capacity as of July 30, 2010 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	86
Total available capacity	$ 2,564

The credit facilities contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. As of June 30, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at June 30, 2010, as calculated pursuant to the terms of the agreement, was 16.1%.

In May 2010, we reduced the maximum allowed borrowings under our commercial paper program from $2.85 billion to approximately $2.2 billion.

Contractual Obligations

At the end of 2009, our commitments included $0.9 billion that related to long-term lease contracts for two deepwater drilling rigs being used in the Gulf of Mexico. As discussed above, we no longer have lease commitments for these two rigs.

At the end of 2009, our commitments also included $0.5 billion that related to a long-term lease contract for a deepwater drilling rig being used in Brazil. Our lease and remaining commitments for this rig will be assumed by the buyer of our assets in Brazil when the associated divestiture transaction closes.

At the end of 2009, our commitments also included $0.4 billion that related to leases of floating, production, storage and offloading facilities being used in the Gulf of Mexico, Brazil and China. Our commitments for the Gulf of Mexico and China leases were assumed by the purchasers in the first half of 2010. Our Brazil lease will be assumed by the buyer when the associated divestiture transaction closes.

Common Share Repurchase Program

As a result of the success we have experienced with our offshore divestiture program, we announced a share repurchase program in May 2010. The program authorizes the repurchase of up to $3.5 billion of our common shares and expires December 31, 2011.

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

Commodity Price Risk

The key terms to all our oil and gas derivatives as of June 30, 2010 are presented in the following tables.

	2010 Gas Price Swaps	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
July December	1,265,000	$ 6.16

2010 Gas Price Collars

Period	Volume (MMBtu/d)	Floor Price: Floor Range ($/MMBtu)	Floor Price: Weighted Average Price ($/MMBtu)	Ceiling Price: Ceiling Range ($/MMBtu)	Ceiling Price: Weighted Average Price ($/MMBtu)
July - December	186,576	$ 4.60 - $5.50	$ 5.13	$ 5.60 - $7.10	$ 6.50

2010 Gas Basis Swaps

Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
July - December	AECO	150,000	$ 0.33
July - December	CIG	70,000	$ 0.37

2011 Gas Price Swaps

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Total year	215,000	$ 5.55

2010 Oil Price Collars

Period	Volume (Bbls/d)	Floor Price: Floor Range ($/Bbl)	Floor Price: Weighted Average Price ($/Bbl)	Ceiling Price: Ceiling Range ($/Bbl)	Ceiling Price: Weighted Average Price ($/Bbl)
July - December	79,000	$ 65.00 - $70.00	$ 67.47	$ 90.35 - $103.30	$ 96.48

2011 Oil Price Collars

Period	Volume (Bbls/d)	Floor Price: Floor Range ($/Bbl)	Floor Price: Weighted Average Price ($/Bbl)	Ceiling Price: Ceiling Range ($/Bbl)	Ceiling Price: Weighted Average Price ($/Bbl)
Total year	33,000	$ 75.00 - $75.00	$ 75.00	$ 105.00 - $116.10	$ 109.00

The fair values of our gas price swaps and collars and oil collars are largely determined by estimates of the forward curves of relevant oil and gas price indexes. At June 30, 2010, a 10% increase in the forward curves associated with our gas price swaps and collars would have decreased the fair value of such instruments by approximately $160 million. A 10% increase in the forward curves associated with our oil collars would have decreased the fair value of such instruments by approximately $90 million.

Interest Rate Risk

At June 30, 2010, we had debt outstanding of $5.6 billion with fixed rates averaging 7.2%.

The key terms of our interest rate derivatives as of June 30, 2010 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

Notional (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$ 700	3.99%	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 June 30, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $46 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% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our June 30, 2010 balance sheet.

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 June 30, 2010 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 second quarter of 2010 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 2009 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 2009 Annual Report on Form 10-K.

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

2010 Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(1) (In millions)
April		$		$ 3,500
May	2,230,128	$ 64.14	2,230,128	$ 3,357
June	5,380,232	$ 65.46	5,380,232	$ 3,005
Total	7,610,360	$ 65.07	7,610,360	

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011.

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

None.

Item 5. ***Other Information***

None.

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.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

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: August 6, 2010

/s/ Danny J. Heatly
Danny J. Heatly
Senior Vice President Accounting and Chief Accounting Officer

INDEX TO EXHIBITS

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