DEVON ENERGY CORP/DE
Form 10-Q
November 04, 2010

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

(Mark One)

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

For the quarterly period ended September 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 October 28, 2010, 431.9 million shares of common stock were outstanding.

DEVON ENERGY CORPORATION
FORM 10-Q
For the Quarterly Period Ended September 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.

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare the December 31, 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.

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PART I. Financial Information

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	September 30, 2010 (Unaudited)	December 31, 2009
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,608	$ 646
Accounts receivable	1,028	1,208
Current assets held for sale	576	657
Other current assets	738	481
Total current assets	5,950	2,992
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	53,563	52,352
Not subject to amortization	3,605	4,078
Total oil and gas	57,168	56,430
Other	4,330	4,045
Total property and equipment, at cost	61,498	60,475
Less accumulated depreciation, depletion and amortization	(43,299)	(41,708)
Property and equipment, net	18,199	18,767
Goodwill	5,977	5,930
Long-term assets held for sale	875	1,250
Other long-term assets	862	747
Total assets	$ 31,863	$ 29,686
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,192	$ 1,137
Revenues and royalties due to others	517	486
Short-term debt	1,808	1,432
Current liabilities associated with assets held for sale	377	234
Other current liabilities	556	513
Total current liabilities	4,450	3,802

Long-term debt	3,821	5,847
Asset retirement obligations	1,394	1,418
Liabilities associated with assets held for sale	69	213
Other long-term liabilities	1,072	937
Deferred income taxes	2,405	1,899
Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 432.2 million and 446.7 million shares in 2010 and 2009, respectively	43	45
Additional paid-in capital	5,714	6,527
Retained earnings	11,390	7,613
Accumulated other comprehensive earnings	1,512	1,385
Treasury stock, at cost. 0.1 million shares in 2010	(7)	
Total stockholders equity	18,652	15,570
Commitments and contingencies (Note 11)		
Total liabilities and stockholders equity	$ 31,863	$ 29,686

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil, gas and NGL sales	$ 1,683	$ 1,481	$ 5,535	$ 4,306
Oil, gas and NGL derivatives	209	23	874	190
Marketing and midstream revenues	461	344	1,396	1,074
Total revenues	2,353	1,848	7,805	5,570
Expenses and other, net:				
Lease operating expenses	415	416	1,271	1,266
Taxes other than income taxes	95	81	288	249
Marketing and midstream operating costs and expenses	336	241	1,013	695
Depreciation, depletion and amortization of oil and gas properties	397	424	1,249	1,414
Depreciation and amortization of non-oil and gas properties	66	64	192	208
Accretion of asset retirement obligations	21	22	71	68
General and administrative expenses	131	136	399	472
Restructuring costs	63		55	
Interest expense	83	90	280	263
Interest-rate and other financial instruments	55	(5)	121	(20)
Reduction of carrying value of oil and gas properties				6,408
Other, net	(8)	(92)	(34)	(61)
Total expenses and other, net	1,654	1,377	4,905	10,962
Earnings (loss) from continuing operations before income taxes	699	471	2,900	(5,392)
Income tax expense (benefit):				
Current	(310)	85	696	135
Deferred	580	4	349	(2,217)
Total income tax expense (benefit)	270	89	1,045	(2,082)
Earnings (loss) from continuing operations	429	382	1,855	(3,310)
Discontinued operations:				
Earnings (loss) from discontinued operations before income taxes	1,710	121	2,320	198

Discontinued operations income tax expense	49	4	187	34
Earnings (loss) from discontinued operations	1,661	117	2,133	164
Net earnings (loss)	$ 2,090	$ 499	$ 3,988	$ (3,146)
Basic earnings (loss) from continuing operations per share	$ 0.99	$ 0.86	$ 4.20	$ (7.46)
Basic earnings (loss) from discontinued operations per share	3.82	0.27	4.82	0.37
Basic net earnings (loss) per share	$ 4.81	$ 1.13	$ 9.02	$ (7.09)
Diluted earnings (loss) from continuing operations per share	$ 0.98	$ 0.86	$ 4.18	$ (7.46)
Diluted earnings (loss) from discontinued operations per share	3.81	0.26	4.81	0.37
Diluted net earnings (loss) per share	$ 4.79	$ 1.12	$ 8.99	$ (7.09)

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (In millions)			
Net earnings (loss)	$ 2,090	$ 499	$ 3,988	$ (3,146)
Foreign currency translation:				
Change in cumulative translation adjustment	223	520	119	826
Foreign currency translation income tax expense	(12)	(31)	(7)	(50)
Foreign currency translation total	211	489	112	776
Pension and postretirement benefit plans:				
Recognition of net actuarial loss and prior service cost in earnings	8	12	24	36
Pension and postretirement benefit plans income tax expense	(3)	(5)	(9)	(13)
Pension and postretirement benefit plans total	5	7	15	23
Other comprehensive earnings (loss), net of tax	216	496	127	799
Comprehensive earnings (loss)	$ 2,306	$ 995	$ 4,115	$ (2,347)

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders Equity
	(Unaudited) (In millions)						
Nine Months Ended September 30, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$	$ 15,570
Net earnings (loss)				3,988			3,988
Other comprehensive earnings (loss), net of tax					127		127
Stock option exercises			18				18
Common stock repurchased						(950)	(950)
Common stock retired	(15)	(2)	(941)			943	
Common stock dividends				(211)			(211)
Share-based compensation			103				103
Share-based compensation tax benefits			7				7
Balance as of September 30, 2010	432	$ 43	$ 5,714	$ 11,390	$ 1,512	$ (7)	$ 18,652
Nine Months Ended September 30, 2009:							
Balance as of December 31, 2008	444	$ 44	$ 6,257	$ 10,376	$ 383	$	$ 17,060
Net earnings (loss)				(3,146)			(3,146)
Other comprehensive earnings (loss), net of tax					799		799
Stock option exercises			19				19
Common stock repurchased						(12)	(12)
Common stock retired			(12)			12	
Common stock dividends				(213)			(213)
Share-based compensation			140				140

Share-based compensation tax benefits			6				6
Balance as of September 30, 2009	444	$ 44	$ 6,410	$ 7,017	$ 1,182	$	$ 14,653

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Earnings (loss) from continuing operations	$ 1,855	$ (3,310)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,441	1,622
Deferred income tax expense (benefit)	349	(2,217)
Reduction of carrying value of oil and gas properties		6,408
Unrealized change in fair value of financial instruments	(136)	184
Other noncash charges	154	182
Net decrease in working capital	164	81
Decrease in long-term other assets	28	17
Increase (decrease) in long-term other liabilities	57	(32)
Cash from operating activities continuing operations	3,912	2,935
Cash from operating activities discontinued operations	324	357
Net cash from operating activities	4,236	3,292
Cash flows from investing activities:		
Proceeds from property and equipment divestitures	4,131	23
Capital expenditures	(4,793)	(3,807)
Redemptions of long-term investments	20	6
Other	(13)	
Cash from investing activities continuing operations	(655)	(3,778)
Cash from investing activities discontinued operations	2,298	(376)
Net cash from investing activities	1,643	(4,154)
Cash flows from financing activities:		
Proceeds from borrowings of long-term debt, net of issuance costs		1,187
Net commercial paper (repayments) borrowings	(1,432)	363
Debt repayments	(350)	(1)
Proceeds from stock option exercises	18	19
Repurchases of common stock	(929)	
Dividends paid on common stock	(211)	(213)
Excess tax benefits related to share-based compensation	7	6
Net cash from financing activities	(2,897)	1,361

Effect of exchange rate changes on cash	5	29
Net increase in cash and cash equivalents	2,987	528
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)	$ 3,998	$ 912

See accompanying notes to consolidated financial statements.

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

2. Accounts Receivable

The components of accounts receivable include the following:

	September 30, 2010	December 31, 2009
	(In millions)	
Oil, gas and NGL sales	$ 612	$ 752
Marketing and midstream revenues	160	188
Joint interest billings	158	151
Production tax credits	85	110
Other	22	19
Gross accounts receivable	1,037	1,220
Allowance for doubtful accounts	(9)	(12)
Net accounts receivable	$ 1,028	$ 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, gas and NGL 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 derivative fair values included in the accompanying consolidated balance sheets.

	Balance Sheet Caption	September 30, 2010	December 31, 2009
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 493	$ 172
Commodity derivatives	Other long-term assets	45	
Interest rate derivatives	Other current assets		39
Interest rate derivatives	Other long-term assets	48	131

Total asset derivatives		$ 586	$ 342
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 14	$ 38
Commodity derivatives	Other long-term liabilities	96	
Interest rate derivatives	Other current liabilities	38	
Total liability derivatives		$ 148	$ 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. Cash settlements and unrealized gains and losses on fair value changes associated with Devon s commodity derivatives are presented in the Oil,

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

gas and NGL derivatives caption in the accompanying consolidated statements of operations. Cash settlements and unrealized gains and losses on fair value changes associated with Devon s interest rate derivatives are presented in the Interest-rate and other financial instruments caption in the accompanying consolidated statements of operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Cash settlements:				
Commodity derivatives	$ 232	$ 127	$ 580	$ 359
Interest rate derivatives	17	14	37	35
Total cash settlements	249	141	617	394
Unrealized gains (losses):				
Commodity derivatives	(23)	(104)	294	(169)
Interest rate derivatives	(72)	(9)	(158)	(15)
Total unrealized gains (losses)	(95)	(113)	136	(184)
Net gain (loss) recognized on statement of operations	$ 154	$ 28	$ 753	$ 210

4. Other Current Assets

The components of other current assets include the following:

	September 30, 2010	December 31, 2009
	(In millions)	
Derivative financial instruments	$ 493	$ 211
Inventories	141	182
Other	104	88
Other current assets	$ 738	$ 481

5. Property and Equipment

Offshore Divestitures

In November 2009, Devon announced plans to reposition itself strategically as a 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 nine months of 2010. Gross proceeds represent contract prices based upon a January 1, 2010 effective date for the Gulf of Mexico and Azerbaijan divestitures, a May 1, 2010 effective date for the China-Panyu divestiture, and a September 1, 2010 effective date for the China-Exploration 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.

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

	Gross Proceeds	After-Tax Proceeds	Proved Reserves (MMBoe)
	(In millions)		(Unaudited)
Gulf of Mexico (continuing operations)	$ 4,145	$ 3,222	91
Azerbaijan (discontinued operations)	2,000	1,924	56
China Panyu (discontinued operations)	515	405	13
China Exploration (discontinued operations)	77	59	
Total	$ 6,737	$ 5,610	160

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. The Azerbaijan divestiture included all of Devon s properties in its Azerbaijan cost center. As a result, Devon recognized a $1.5 billion ($1.5 billion after-tax) gain during the third quarter of 2010 in connection with the Azerbaijan divestiture. 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 in the second quarter of 2010. No gain was recognized upon the divestiture of Devon s exploratory assets in China in the third quarter of 2010. These gains are included in earnings from discontinued operations in the accompanying 2010 consolidated statements of operations.

Pending Transaction

Devon has entered into an agreement to sell its assets in Brazil for $3.2 billion. This 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 a gain upon the close of the transaction.

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 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 September 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 7 for more information regarding the promissory note.

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

6. Goodwill

During the first nine months of 2010, Devon s Canadian goodwill increased $47 million. This increase was entirely due to foreign currency translation.

Devon removed all its International goodwill in conjunction with the Azerbaijan divestiture that closed in the third quarter of 2010. Such goodwill totalled $68 million and was presented in long-term assets held for sale in the accompanying December 31, 2009 consolidated balance sheet.

7. Debt

Commercial Paper

Devon repaid $1.4 billion of commercial paper borrowings during the first and second quarters of 2010 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 September 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%. At September 30, 2010, the note had a carrying value of $143 million, of which $59 million is presented as short-term debt and the remainder is presented as long-term debt in the accompanying 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 September 30, 2010 (in millions).

April 7, 2012 maturity	$ 463
April 7, 2013 maturity	2,187
Total Senior Credit Facility	2,650
Less:	
Outstanding Senior Credit Facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	37
Total available capacity	$ 2,613

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

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 September 30, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at September 30, 2010, as calculated pursuant to the terms of the agreement, was 15.3%.

Interest Expense

The following schedule includes the components of interest expense.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Interest based on debt outstanding	$ 98	$ 112	$ 307	$ 330
Capitalized interest	(20)	(22)	(55)	(71)
Early retirement of debt			19	
Other	5		9	4
Total	$ 83	$ 90	$ 280	$ 263

8. Asset Retirement Obligations

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

	Nine Months Ended September 30,	
	2010	2009
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,513	$ 1,387
Liabilities incurred	36	50
Liabilities settled	(94)	(75)
Revision of estimated obligation	194	22
Liabilities assumed by others	(256)	(17)
Accretion expense on discounted obligation	71	68
Foreign currency translation adjustment	10	82
Asset retirement obligations as of end of period	1,474	1,517
Less current portion	80	108
Asset retirement obligations, long-term	$ 1,394	$ 1,409

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

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9. 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 September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009	2010	2009	2010	2009
	(In millions)							
Service cost	$ 9	$ 11	$ 25	$ 33	$	$	$	$
Interest cost	15	14	43	42	1	1	3	3
Expected return on plan assets	(10)	(9)	(28)	(27)				
Amortization of prior service cost		1	2	3	1		1	
Net actuarial loss	7	11	21	33				
Net periodic benefit cost	$ 21	$ 28	$ 63	$ 84	$ 2	$ 1	$ 4	$ 3

10. Stockholders Equity

Stock Repurchases

During the first nine months of 2010, Devon repurchased 14.7 million common shares under its $3.5 billion stock repurchase program for $936 million, or $63.61 per share. This program expires December 31, 2011.

Dividends

Devon paid common stock dividends of $211 million and $213 million (quarterly rates of $0.16 per share) in the first nine months of 2010 and 2009, respectively.

11. 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.

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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.

12. Fair Value Measurements

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

			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(In millions)		
September 30, 2010 assets (liabilities):					
Commodity derivatives	$ 428	$ 428	$	$ 428	$
Interest rate derivatives	$ 10	$ 10	$	$ 10	$
Debt	$ (5,629)	$ (6,747)	$	$ (6,604)	$ (143)
Long-term investments	$ 95	$ 95	$	$	$ 95
December 31, 2009 assets (liabilities):					
Commodity derivatives	$ 134	$ 134	$	$ 134	$
Interest rate derivatives	$ 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. Included below is a summary of the changes in Devon s Level 3 fair value measurements during the first nine months of 2010 and 2009.

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	Debt	Long-Term Investments
	(In millions)	
December 31, 2009	$	$ 115
Issuance of promissory note	(139)	
Foreign exchange translation adjustment	(4)	
Accretion of promissory note	(1)	
Redemptions of principal	1	(20)
September 30, 2010	$ (143)	$ 95
December 31, 2008	$	$ 122
Redemptions of principal		(6)
September 30, 2009	$	$ 116

13. Restructuring Costs

Employee Severance

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 and a significant part of its International assets by the end of the third quarter of 2010. As a result of these divestitures and associated employee terminations, Devon decreased its estimate of employee severance costs in the second and third quarters of 2010 by $14 million and $21 million, respectively. As a result, Devon now estimates it will incur approximately $118 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 $118 million total, $78 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations. Of the $35 million reduction recognized during 2010, $27 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations.

Lease Obligations

As a result of the divestitures discussed above, Devon ceased using certain office space that was subject to non-cancellable operating lease arrangements. Consequently, in the third quarter of 2010, Devon recognized $70 million of restructuring costs that represent the present value of its future obligations under the leases, net of anticipated sublease income. Devon s estimate of lease obligations was based upon certain key estimates that could change over the term of the leases. These estimates include the estimated sublease income that Devon may receive over the term of the leases, as well as the amount of variable operating costs that Devon will be required to pay under the leases.

Asset Impairments

In the third quarter of 2010, Devon recognized $11 million of asset impairment charges for leasehold improvements and furniture associated with the office space it ceased using.

Financial Statement Presentation

Recognition and adjustments to cash severance, accelerated vesting of share-based grants, lease obligations and asset impairments are included in restructuring costs in the accompanying 2010 consolidated statements of operations. Amounts related to cash severance and lease obligations are accrued for in other current liabilities and other long-term liabilities in the

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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. Asset impairments are presented as a reduction to Devon s net property and equipment in the accompanying consolidated 2010 balance sheet.

The schedule below summarizes activity and balances associated with Devon s restructuring liabilities.

	Other Current Liabilities			Other Long-Term Liabilities		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Balance as of December 31, 2009	$ 61	$ 23	$ 84	$	$	$
Lease obligations incurred	17		17	53		53
Cash severance paid	(17)	(3)	(20)			
Cash severance revision	(18)	(5)	(23)			
Balance as of September 30, 2010	$ 43	$ 15	$ 58	$ 53	$	$ 53

The schedule below summarizes the components of restructuring costs in the accompanying consolidated statements of operations.

	Three Months Ended September 30, 2010			Nine Months Ended September 30, 2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Cash severance	$ (13)	$ (1)	$ (14)	$ (18)	$ (4)	$ (22)
Share-based awards	(5)	(2)	(7)	(9)	(4)	(13)
Lease obligations	70		70	70		70
Asset impairments	11		11	11		11
Other				1		1
Restructuring costs	$ 63	$ (3)	$ 60	$ 55	$ (8)	$ 47

14. 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.

15. Income Taxes

The Gulf of Mexico divestitures discussed in Note 5 have taxable gains that increase Devon s current income tax expense of $858 million. However, the additional current income taxes are offset by a decrease in deferred income tax expense, resulting in no impact to Devon s total income tax expense.

Additionally, in conjunction with the filing of its 2009 income tax return in the third quarter of 2010, Devon recognized a $220 million decrease to current income tax expense that was offset by a like increase to deferred income tax expense. These amounts relate to a change in the timing of certain deductions which Devon elected to expense rather than capitalize for the 2009 tax year. Such deductions created a net operating loss for the 2009 tax year that Devon is using to reduce its 2010 current income taxes that would otherwise be due as a result of the taxable divestiture gains mentioned above.

In the third quarter of 2009, Devon recognized $59 million of income tax benefits in conjunction with the initial or amended filings of its 2005, 2006, 2007 and 2008 income tax returns. These tax benefits consist of deferred tax benefits of $50 million and current tax benefits of $9 million. Of the $59 million, $41 million relates to taxation on foreign operations. The remaining $18 million relates to taxation on U.S. federal and state operations.

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16. Discontinued Operations

Revenues related to Devon s discontinued operations totaled $139 million and $573 million in the third quarter and first nine months of 2010, respectively, and $250 million and $646 million in the third quarter and first nine months of 2009, respectively.

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

	September 30, 2010	December 31, 2009
	(In millions)	
Cash and cash equivalents	$ 390	$ 365
Accounts receivable	49	165
Other current assets	137	127
Current assets	$ 576	$ 657
Property and equipment, net	$ 816	$ 1,099
Goodwill		68
Other long-term assets	59	83
Total long-term assets	$ 875	$ 1,250
Accounts payable	$ 324	$ 158
Other current liabilities	53	76
Current liabilities	$ 377	$ 234
Asset retirement obligations	$ 29	$ 109
Deferred income taxes	35	101
Other liabilities	5	3
Long-term liabilities	$ 69	$ 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.

Divestitures

See Note 5 for more information on the Azerbaijan and China divestitures.

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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 nine-month periods ended September 30, 2010 and 2009. Because a net loss from continuing operations was generated during the nine-month period ended September 30, 2009, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share amount from continuing operations in the nine months ended September 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 September 30, 2010:			
Earnings from continuing operations	$ 429	435	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	425	430	$ 0.99
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		1	
Diluted earnings per share	$ 425	431	$ 0.98
Three Months Ended September 30, 2009:			
Earnings from continuing operations	$ 382	444	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	378	439	$ 0.86
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 378	441	$ 0.86
Nine Months Ended September 30, 2010:			
Earnings from continuing operations	$ 1,855	442	
Attributable to participating securities	(21)	(5)	
Basic earnings per share	1,834	437	$ 4.20
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 1,834	439	$ 4.18

Nine Months Ended September 30, 2009:			
Loss from continuing operations	$ (3,310)	444	
Attributable to participating securities	36	(5)	
Basic and diluted loss per share	$ (3,274)	439	$ (7.46)

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 nine-month periods ended September 30, 2010, 8.6 million shares and 7.9 million shares, respectively, were excluded from the diluted earnings per share calculations. During the three-month and nine-month periods ended September 30, 2009, 7.1 million shares and 8.9 million shares, respectively, were excluded from the diluted earnings per share calculations.

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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 September 30, 2010:				
Current assets	$ 2,299	$ 3,075	$ 576	$ 5,950
Property and equipment, net	11,509	6,690		18,199
Goodwill	3,046	2,931		5,977
Other assets	517	345	875	1,737
Total assets	$ 17,371	$ 13,041	$ 1,451	$ 31,863
Current liabilities	$ 1,578	$ 2,495	$ 377	$ 4,450
Long-term debt	2,503	1,318		3,821
Asset retirement obligations	564	830		1,394
Other liabilities	1,025	47	69	1,141
Deferred income taxes	1,240	1,165		2,405
Stockholders equity	10,461	7,186	1,005	18,652
Total liabilities and stockholders equity	$ 17,371	$ 13,041	$ 1,451	$ 31,863

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	U.S.	Canada (In millions)	Total
Three Months Ended September 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,104	$ 579	$ 1,683
Oil, gas and NGL derivatives	214	(5)	209
Marketing and midstream revenues	432	29	461
Total revenues	1,750	603	2,353
Expenses and other, net:			
Lease operating expenses	208	207	415
Taxes other than income taxes	85	10	95
Marketing and midstream operating costs and expenses	314	22	336
Depreciation, depletion and amortization of oil and gas properties	234	163	397
Depreciation and amortization of non-oil and gas properties	60	6	66
Accretion of asset retirement obligations	8	13	21
General and administrative expenses	97	34	131
Restructuring costs	63		63
Interest expense	36	47	83
Interest-rate and other financial instruments	55		55
Other, net	(7)	(1)	(8)
Total expenses and other, net	1,153	501	1,654
Earnings from continuing operations before income taxes	597	102	699
Income tax expense (benefit):			
Current	(349)	39	(310)
Deferred	590	(10)	580
Total income tax expense	241	29	270
Earnings from continuing operations	$ 356	$ 73	$ 429
Capital expenditures, continuing operations	$ 1,358	$ 308	$ 1,666

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	U.S.	Canada (In millions)	Total
Three Months Ended September 30, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 961	$ 520	$ 1,481
Oil, gas and NGL derivatives	23		23
Marketing and midstream revenues	333	11	344
Total revenues	1,317	531	1,848
Expenses and other, net:			
Lease operating expenses	244	172	416
Taxes other than income taxes	72	9	81
Marketing and midstream operating costs and expenses	236	5	241
Depreciation, depletion and amortization of oil and gas properties	270	154	424
Depreciation and amortization of non-oil and gas properties	58	6	64
Accretion of asset retirement obligations	12	10	22
General and administrative expenses	108	28	136
Interest expense	34	56	90
Interest-rate and other financial instruments	(5)		(5)
Other, net	(99)	7	(92)
Total expenses and other, net	930	447	1,377
Earnings from continuing operations before income taxes	387	84	471
Income tax expense (benefit):			
Current	27	58	85
Deferred	30	(26)	4
Total income tax expense	57	32	89
Earnings from continuing operations	$ 330	$ 52	$ 382
Capital expenditures, continuing operations	$ 696	$ 247	$ 943

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	U.S.	Canada (In millions)	Total
Nine Months Ended September 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 3,618	$ 1,917	$ 5,535
Oil, gas and NGL derivatives	871	3	874
Marketing and midstream revenues	1,300	96	1,396
Total revenues	5,789	2,016	7,805
Expenses and other, net:			
Lease operating expenses	675	596	1,271
Taxes other than income taxes	258	30	288
Marketing and midstream operating costs and expenses	935	78	1,013
Depreciation, depletion and amortization of oil and gas properties	743	506	1,249
Depreciation and amortization of non-oil and gas properties	173	19	192
Accretion of asset retirement obligations	33	38	71
General and administrative expenses	303	96	399
Restructuring costs	55		55
Interest expense	121	159	280
Interest-rate and other financial instruments	121		121
Other, net	(36)	2	(34)
Total expenses and other, net	3,381	1,524	4,905
Earnings from continuing operations before income taxes	2,408	492	2,900
Income tax expense (benefit):			
Current	496	200	696
Deferred	404	(55)	349
Total income tax expense	900	145	1,045
Earnings from continuing operations	$ 1,508	$ 347	$ 1,855
Capital expenditures, before revision of future asset retirement obligations	$ 3,547	$ 1,452	$ 4,999
Revision of future asset retirement obligations	72	122	194
Capital expenditures, continuing operations	$ 3,619	$ 1,574	$ 5,193

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	U.S.	Canada (In millions)	Total
Nine Months Ended September 30, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 2,806	$ 1,500	$ 4,306
Oil, gas and NGL derivatives	190		190
Marketing and midstream revenues	1,048	26	1,074
Total revenues	4,044	1,526	5,570
Expenses and other, net:			
Lease operating expenses	766	500	1,266
Taxes other than income taxes	223	26	249
Marketing and midstream operating costs and expenses	682	13	695
Depreciation, depletion and amortization of oil and gas properties	984	430	1,414
Depreciation and amortization of non-oil and gas properties	189	19	208
Accretion of asset retirement obligations	40	28	68
General and administrative expenses	384	88	472
Interest expense	95	168	263
Interest-rate and other financial instruments	(20)		(20)
Reduction of carrying value of oil and gas properties	6,408		6,408
Other, net	(84)	23	(61)
Total expenses and other, net	9,667	1,295	10,962
Earnings (loss) from continuing operations before income taxes	(5,623)	231	(5,392)
Income tax expense (benefit):			
Current	31	104	135
Deferred	(2,194)	(23)	(2,217)
Total income tax expense (benefit)	(2,163)	81	(2,082)
Earnings (loss) from continuing operations	$ (3,460)	$ 150	$ (3,310)
Capital expenditures, before revision of future asset retirement obligations	$ 2,598	$ 733	$ 3,331
Revision of future asset retirement obligations	37	(15)	22
Capital expenditures, continuing operations	$ 2,635	$ 718	$ 3,353

19. Supplemental Information to Statements of Cash Flows

Information related to Devon s cash flows is presented below.

Nine Months

	Ended September 30,	
	2010	2009
	(In millions)	
Net (increase) decrease in working capital:		
Decrease in accounts receivable	$ 185	$ 285
Decrease in other current assets	11	171
Increase (decrease) in accounts payable	49	(50)
Increase (decrease) in revenues and royalties due to others	29	(124)
Decrease in other current liabilities	(110)	(201)
Net decrease in working capital	$ 164	$ 81
Supplementary cash flow data continuing and discontinued operations:		
Interest paid net of capitalized interest	$ 338	$ 273
Income taxes paid (received)	$ 745	$ (29)

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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 nine-month periods ended September 30, 2010, compared to the three-month and nine-month periods ended September 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.

Financial Overview

During the third quarter and first nine months of 2010, we generated net earnings of $2.1 billion, or $4.79 per diluted share, and $4.0 billion, or $8.99 per diluted share, for the respective periods. This compares to net earnings of $499 million, or $1.12 per diluted share, for the third quarter of 2009 and a net loss of $3.1 billion, or $7.09 per diluted share for the first nine months of 2009. Our financial results for the third quarter and first nine months of 2010 include after-tax gains of $1.5 billion and $1.8 billion, respectively, related to International offshore divestitures. Our financial results for the first nine months 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 financial performance for the third quarter and first nine months of 2010 compared to 2009 are summarized below:

- Production decreased 3% and 4% in the third quarter and first nine months of 2010, respectively. Excluding the effects of property divestitures, North America Onshore production climbed 4% and declined 1% for the respective third quarter and nine month comparisons.

- The combined realized price without hedges for oil, gas and NGLs increased 17% and 33% in the third quarter and first nine months of 2010, respectively.

- Oil, gas and NGL derivatives generated net gains of $209 million and $874 million in the third quarter and first nine months of 2010, respectively, and net gains of $23 million and $190 million in the third quarter and first nine months of 2009. Included in these amounts were cash receipts of $232 million and $580 million for the third quarter and first nine months of 2010, respectively, and cash receipts of $127 million and $359 million in the third quarter and first nine months of 2009, respectively.

- Marketing and midstream operating profit increased 20% to $125 million and 1% to $383 million in the third quarter and first nine months of 2010, respectively.

- Per unit operating costs increased 3% to $7.35 per Boe and 4% to $7.44 per Boe in the third quarter and first nine months of 2010, respectively.

- Operating cash flow increased 29% to $4.2 billion in the first nine months of 2010.

- Including a $500 million acquisition of a 50 percent interest in the Pike oil sands, cash spent on capital expenditures was approximately $4.8 billion in the first nine months of 2010.

Throughout 2010, we have moved closer to completion of our offshore divestiture program announced in November 2009. We have completed our exit from the Gulf of Mexico and have divested our assets in Azerbaijan and China. Additionally, we have entered into an agreement to sell our assets in Brazil for $3.2 billion. This transaction continues to progress through the approval process of the Brazilian government and is on track to close around the end of 2010. The divestiture process is ongoing for our exploration assets in Angola.

During the first nine months of 2010, our divestitures generated total after-tax proceeds of $5.6 billion. In accordance with full cost accounting rules, we did not recognize a gain on the Gulf of Mexico divestitures. The Azerbaijan and China divestitures generated gains of $1.5 billion ($1.5 billion after-tax) and $0.3 billion ($0.2 billion after-tax), respectively.

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.

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.

In May 2010, we announced a share repurchase program that authorizes the repurchase of up to $3.5 billion of our common shares. Through September, we had repurchased 14.7 million shares for $936 million, or $63.61 per share.

Additionally, 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.

Finally, our performance and divestitures to date enabled us to end the third quarter of 2010 with a robust level of liquidity. As of September 30, 2010, we held $4.0 billion in cash and cash equivalents 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.

Third-Quarter Operating Highlights

We drilled 407 wells in the third quarter of 2010 with an overall success rate of 99 percent. We achieved several notable operational accomplishments in the third-quarter:

- Our oil and natural gas liquids production totaled 193 thousand barrels per day in the third quarter of 2010. This represents an 11% increase in liquids production compared to the third quarter of 2009.

- In the Permian Basin, increased oil and liquids-rich activity drove production 18% higher than the year-ago quarter to 44,000 barrels per day. We are currently running 17 operated rigs and have assembled nearly 1 million net acres of leasehold targeting the Avalon Shale, Bone Spring, Wolfberry and other conventional formations.

- In Canada, net production from our Jackfish oil sands project averaged 21,300 barrels per day in the third quarter. Jackfish was taken offline for scheduled plant maintenance during the last three weeks of the third quarter and resumed operations on September 30, 2010.

- Construction of our second Jackfish oil sands project is now approximately 90% complete. We plan to commence steam injection at Jackfish 2 in the second quarter of 2011, with first production expected by the end of next year.

- We sanctioned our third Jackfish development project and filed a regulatory application in the third quarter. We could begin facilities construction at Jackfish 3 by the end of 2011, with plant start-up targeted for 2015.

- Production from our Cana-Woodford Shale play in western Oklahoma averaged a record 117 million cubic feet of gas equivalent per day during the quarter. This represents an increase in production of 122% over the year-ago quarter. We expect to commence operations from our Cana gas processing plant by the end of 2010.

- In the Granite Wash in the Texas panhandle, we drilled three significant horizontal wells in the third quarter. Initial production from these wells averaged 4,290 barrels of oil-equivalent per day, including 605 barrels of oil and 1,450 barrels of natural gas liquids per day. We have an average working interest of 65% in these wells.

- We increased our net production from the Barnett Shale field in north Texas to an all-time high of 1.2 billion cubic feet of natural gas equivalent per day in the third quarter, including 40,100 barrels per day of liquids production. This represents an 8% increase in production compared to the third quarter of 2009.

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Results of Operations

Revenues

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change[(2)]	2010	2009	Change[(2)]
Oil (MMBbls)						
U.S. Onshore	4	2	+27%	10	8	+13%
Canada	6	6	+4%	19	19	+2%
North America Onshore	10	8	+11%	29	27	+6%
U.S. Offshore		2	-100%	2	4	-50%
Total	10	10	-5%	31	31	-1%
Gas (Bcf)						
U.S. Onshore	179	172	+4%	518	536	-3%
Canada	53	58	-9%	161	171	-6%
North America Onshore	232	230	+1%	679	707	-4%
U.S. Offshore		12	-100%	17	34	-50%
Total	232	242	-4%	696	741	-6%
NGLs (MMBbls)						
U.S. Onshore	7	6	+12%	21	19	+9%
Canada	1	1	-3%	3	3	-5%
North America Onshore	8	7	+10%	24	22	+7%
U.S. Offshore		1	-100%		1	-38%
Total	8	8	+8%	24	23	+6%
Total (MMBoe) (1)						
U.S. Onshore	41	38	+7%	117	117	+0%
Canada	16	16	-4%	49	50	-3%
North America Onshore	57	54	+4%	166	167	-1%
U.S. Offshore		4	-100%	5	10	-49%
Total	57	58	-3%	171	177	-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, gas and NGL derivatives.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
Oil (per Bbl)						
U.S. Onshore	$ 71.47	$ 64.48	+11%	$ 73.56	$ 51.04	+44%
Canada	$ 56.89	$ 55.10	+3%	$ 57.90	$ 43.42	+33%
North America Onshore	$ 62.31	$ 58.15	+7%	$ 63.22	$ 45.83	+38%
U.S. Offshore	$	$ 65.99	N/M	$ 77.81	$ 56.19	+38%
Total	$ 62.31	$ 59.32	+5%	$ 64.12	$ 47.09	+36%
Gas (per Mcf)						
U.S. Onshore	$ 3.65	$ 2.77	+32%	$ 3.91	$ 2.99	+31%
Canada	$ 3.72	$ 2.91	+28%	$ 4.24	$ 3.51	+21%
North America Onshore	$ 3.67	$ 2.81	+31%	$ 3.99	$ 3.11	+28%
U.S. Offshore	$	$ 3.49	N/M	$ 5.12	$ 4.11	+25%
Total	$ 3.67	$ 2.84	+29%	$ 4.02	$ 3.16	+27%

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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change	2010	2009	Change
NGLs (per Bbl)						
U.S. Onshore	$ 27.21	$ 24.49	+11%	$ 29.92	$ 20.98	+43%
Canada	$ 43.89	$ 33.81	+30%	$ 46.34	$ 30.20	+53%
North America Onshore	$ 29.01	$ 25.63	+13%	$ 31.81	$ 22.18	+43%
U.S. Offshore	$	$ 28.34	N/M	$ 38.22	$ 23.51	+63%
Total	$ 29.01	$ 25.67	+13%	$ 31.90	$ 22.21	+44%
Combined (per Boe) (1)						
U.S. Onshore	$ 27.18	$ 21.48	+27%	$ 28.83	$ 20.86	+38%
Canada	$ 36.62	$ 31.62	+16%	$ 39.33	$ 29.94	+31%
North America Onshore	$ 29.82	$ 24.54	+22%	$ 31.92	$ 23.58	+35%
U.S. Offshore	$	$ 39.67	N/M	$ 49.06	$ 36.64	+34%
Total	$ 29.82	$ 25.50	+17%	$ 32.42	$ 24.31	+33%

(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 September 30, 2010 and 2009.

	Oil	Gas	NGLs	Total
		(In millions)		
2009 sales	$ 597	$ 689	$ 195	$ 1,481
Changes due to volumes	(33)	(29)	16	(46)
Changes due to prices	29	191	28	248
2010 sales	$ 593	$ 851	$ 239	$ 1,683

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

	Oil	Gas	NGLs	Total
		(In millions)		
2009 sales	$ 1,465	$ 2,340	$ 501	$ 4,306
Changes due to volumes	(14)	(141)	29	(126)
Changes due to prices	525	599	231	1,355
2010 sales	$ 1,976	$ 2,798	$ 761	$ 5,535

Oil Sales

Oil sales increased $29 million in the third quarter of 2010 as a result of a 5% 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 decreased $33 million in the third quarter of 2010 due to a five percent decrease in production. The decrease was primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010 partially offset by a 11% increase in our North America Onshore production. The increased North America Onshore production resulted primarily from continued development of our Permian Basin properties in Texas and our Jackfish operations in Canada.

Oil sales increased $525 million in the first nine months of 2010 as a result of a 36% 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.

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Oil sales decreased $14 million in the first nine months of 2010 due to a one percent decrease in production. The decrease was comprised of the net effects of a 50% decrease in our U.S. Offshore production and a 6% increase in our North America Onshore production. The decrease in our U.S. Offshore production was primarily due to the divestiture of such properties in the second quarter of 2010. The increased North America Onshore production resulted primarily from continued development of our Permian Basin properties in Texas and our Jackfish operations in Canada.

Gas Sales

Gas sales increased $191 million during the third quarter of 2010 as a result of a 29% 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 4% decrease in production during the third quarter of 2010 caused gas sales to decrease by $29 million. The decrease was primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010 partially offset by a 1% increase in our North America Onshore production. The increased North America Onshore production resulted primarily from continued development activities in the Barnett and Cana Shales, partially offset by natural production declines in our other operating areas.

Gas sales increased $599 million during the first nine months 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 6% decrease in production during the first nine months of 2010 caused gas sales to decrease by $141 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 reduced drilling activities during the second half of 2009 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 to the decrease.

NGL Sales

NGL sales increased $28 million during the third quarter of 2010 as a result of a 13% increase in our realized price without hedges. The increase was largely due to an increase in the Mont Belvieu, Texas index price over the same time period. NGL sales increased $16 million in the third quarter of 2010 due to an eight percent increase in production. The increase in production is primarily due to increased drilling in North America Onshore areas that have liquids rich gas.

NGL sales increased $231 million during the first nine months of 2010 as a result of a 44% increase in our realized price without hedges. The increase was largely due to an increase in the Mont Belvieu, Texas index price over the same time period. NGL sales increased $29 million in the first nine months of 2010 due to a six percent increase in production. The increase in production is primarily due to increased drilling in North America Onshore areas that have liquids rich gas.

Oil, Gas and NGL Derivatives

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

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	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In millions)			
Cash settlements receipts:				
Gas price swaps	$ 206	$ 9	$ 543	$ 9
Gas price collars	17	118	30	350
Gas basis swaps	9		7	
Total cash settlements	232	127	580	359
Unrealized gains (losses) on fair value changes:				
Gas price swaps	145	(7)	303	(7)
Gas price collars	12	(104)	31	(169)
Gas basis swaps	(14)		(2)	
Gas call options	(42)		(42)	
Oil price collars	(57)	7	71	7
Oil call options	(68)		(68)	
NGL basis swaps	1		1	
Total unrealized gains (losses) on fair value changes	(23)	(104)	294	(169)
Oil, gas and NGL derivatives	$ 209	$ 23	$ 874	$ 190

	Three Months Ended September 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 62.31	$ 3.67	$ 29.01	$ 29.82
Cash settlements of hedges		1.00		4.14
Realized price, including cash settlements	$ 62.31	$ 4.67	$ 29.01	$ 33.96

	Three Months Ended September 30, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 59.32	$ 2.84	$ 25.67	$ 25.50
Cash settlements of hedges		0.52		2.19
Realized price, including cash settlements	$ 59.32	$ 3.36	$ 25.67	$ 27.69

Nine Months Ended September 30, 2010

	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 64.12	$ 4.02	$ 31.90	$ 32.42
Cash settlements of hedges		0.83		3.40
Realized price, including cash settlements	$ 64.12	$ 4.85	$ 31.90	$ 35.82

	Nine Months Ended September 30, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 47.09	$ 3.16	$ 22.21	$ 24.31
Cash settlements of hedges		0.48		2.03
Realized price, including cash settlements	$ 47.09	$ 3.64	$ 22.21	$ 26.34

In 2010, our oil, gas and NGL derivatives included gas price swaps, oil and gas costless price collars, gas and NGL basis swaps, and oil and gas call options. In 2009, our oil and gas derivatives included gas price swaps and oil and gas costless 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 index prices and pay a variable differential on the same two index prices to the contract counterparty. The oil and gas call options give the counterparty the right to place us into an oil or gas price swap at a predetermined fixed price. Cash settlements as presented in the tables above represent net realized gains related to our price swaps, price collars and basis swaps.

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During the third quarter and first nine months of 2010, we received $232 million, or $1.00 per Mcf, and $580 million, or $0.83 per Mcf, respectively, from counterparties to settle our gas derivatives. During the third quarter and first nine months of 2009, we received $127 million, or $0.52 per Mcf, and $359 million, or $0.48 per Mcf, respectively, from counterparties to settle our gas derivatives. We had no settlements on oil or NGL 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, gas and NGL derivatives in each reporting period. We estimate the fair values of our oil, gas and NGL 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 September 30, 2010, a 10% increase in these forward curves would have decreased the fair value of our gas derivatives by approximately $163 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 $95 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 fourteen 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 September 30, 2010, the credit ratings of all our counterparties were investment grade.

Including the cash settlements discussed above, the net gains from our oil, gas and NGL derivatives were $209 million and $874 million during the third quarter and first nine months of 2010, respectively. Including the cash settlements discussed above, the net gains from our oil, gas and NGL derivatives were $23 million and $190 million during the third quarter and first nine months 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, gas and NGL derivative positions as of the end of the third 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 September 30,			Nine Months Ended September 30,		
	2010	**2009**	**Change(1)**	**2010**	**2009**	**Change(1)**
			($ in millions)			
Marketing and midstream:						
Revenues	$ 461	$ 344	+34%	$ 1,396	$ 1,074	+30%
Operating costs and expenses	336	241	+40%	1,013	695	+46%
Operating profit	$ 125	$ 103	+20%	$ 383	$ 379	+1%

(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 third quarter of 2010, marketing and midstream revenues increased $117 million and operating costs and expenses increased $95 million, causing operating profit to increase $22 million. Revenues, expenses and operating profit increased primarily due to higher commodity prices and natural gas and NGL production.

During the first nine months of 2010, marketing and midstream revenues increased $322 million and operating costs and expenses increased $318 million, causing operating profit to increase $4 million. Revenues, expenses and operating profit

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increased primarily due to higher commodity prices and NGL production, partially offset by the effects of lower gas pipeline throughput and lower gas marketing profits.

Lease Operating Expenses (LOE)

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Change(1)	2010	2009	Change(1)
Lease operating expenses ($ in millions):						
U.S. Onshore	$ 208	$ 198	+5%	$ 615	$ 639	-4%
Canada	207	172	+21%	596	500	+19%
North America Onshore	415	370	+12%	1,211	1,139	+6%
U.S. Offshore		46	-100%	60	127	-52%
Total	$ 415	$ 416	-0%	$ 1,271	$ 1,266	+0%
Lease operating expenses per Boe:						
U.S. Onshore	$ 5.11	$ 5.22	-2%	$ 5.25	$ 5.45	-4%
Canada	$ 13.14	$ 10.44	+26%	$ 12.23	$ 9.98	+23%
North America Onshore	$ 7.35	$ 6.80	+8%	$ 7.30	$ 6.81	+7%
U.S. Offshore	$	$ 12.48	N/M	$ 12.00	$ 12.83	-7%
Total	$ 7.35	$ 7.16	+3%	$ 7.44	$ 7.14	+4%

(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 decreased $1 million in the third quarter of 2010, which included a $46 million decrease related to our U.S. Offshore operations and a $45 million increase related to our North America Onshore operations. Our U.S. Offshore LOE decreased as a result of the divestiture of such properties in the second quarter of 2010. Our North America Onshore LOE increased $14 million as a result of our 4% increase in production and $11 million due to changes in the exchange rate between the U.S. and Canadian dollars. The remaining increase primarily relates to increased costs related to our Jackfish operations in Canada. The higher Jackfish costs relate to maintenance performed during the third quarter of 2010, as well as clean up and repair costs associated with a temporary, uncontrolled steam release in July 2010. These factors were also the main contributors to the changes in LOE per Boe.

LOE increased $5 million in the first nine months of 2010, which included a $72 million increase related to our North America Onshore operations and a $67 million decrease related to our U.S. Offshore operations. North America Onshore LOE increased $69 million due to changes in the exchange rate between the U.S. and Canadian dollars. North America Onshore LOE also increased $14 million due to increased costs related to our Jackfish operation in Canada. A 1% decrease in North America Onshore production caused LOE to decline $11 million. U.S. Offshore LOE decreased primarily due to property divestitures in the second quarter of 2010. The increase due to exchange rates was also the main contributor to the changes in North America Onshore and total LOE per Boe.

Taxes Other Than Income Taxes

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

Three Months Ended September 30,	Nine Months Ended September 30,

	2010	2009	Change(1)	2010	2009	Change(1)
			($ in millions)			
Production	$ 51	$ 35	+46%	$ 156	$ 95	+64%
Ad valorem	42	45	-7%	128	148	-14%
Other	2	1	+11%	4	6	-38%
Total	$ 95	$ 81	+16%	$ 288	$ 249	+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 $16 million and $61 million in the third quarter and first nine months of 2010, respectively, primarily due to an increase in our U.S. Onshore revenues. Ad valorem taxes decreased $3 million and $20 million respectively, primarily due to lower estimated assessed values of our U.S. Onshore 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 September 30,			Nine Months Ended September 30,		
	2010	**2009**	**Change(1)**	**2010**	**2009**	**Change(1)**
Total production volumes (MMBoe)	57	58	-3%	171	177	-4%
DD&A rate ($ per Boe)	$ 7.04	$ 7.30	-4%	$ 7.32	$ 7.98	-8%
DD&A expense ($ in millions)	$ 397	$ 424	-6%	$ 1,249	$ 1,414	-12%

(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 nine months ended September 30, 2010 and 2009.

	Three Months Ended September 30,	Nine Months Ended September 30,
	(In millions)	
2009 DD&A	$ 424	$ 1,414
Change due to volumes	(12)	(51)
Change due to rate	(15)	(114)
2010 DD&A	$ 397	$ 1,249

Oil and gas property-related DD&A decreased $15 million during the third quarter of 2010 due to a 4% decrease in the DD&A rate. The rate decreased primarily due to our U.S. Offshore property divestitures in 2010. This was partially offset by our drilling and development activities subsequent to the end of the third quarter of 2009, which resulted in proved reserve additions at a cost higher than the third quarter 2009 DD&A rate, causing the rate to increase. In addition, changes in the exchange rate between the U.S. and Canadian dollars also increased our rate.

Oil and gas property-related DD&A decreased $114 million during the first nine months of 2010 due to a 8% decrease in the DD&A rate. The largest contributors to the rate decrease were our 2010 U.S. Offshore property divestitures and 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. These decreases were partially offset by the effect from drilling and development activities, as well as changes in the exchange rate between the U.S. and Canadian dollars, 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 September 30,			Nine Months Ended September 30,		
	2010	2009	Change(1)	2010	2009	Change(1)
			($ in millions)			
Gross G&A	$ 235	$ 249	-6%	$ 720	$ 830	-13%
Capitalized G&A	(75)	(80)	-6%	(236)	(261)	-9%
Reimbursed G&A	(29)	(33)	-16%	(85)	(97)	-13%
Net G&A	$ 131	$ 136	-3%	$ 399	$ 472	-15%

(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 and capitalized G&A decreased $14 million and $5 million, respectively, in the third quarter of 2010 compared to the same period in 2009. The largest contributor to these decreases was lower employee compensation and benefits resulting primarily from our 2010 offshore divestitures. These decreases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollars.

Gross G&A and capitalized G&A decreased $110 million and $25 million, respectively, in the first nine months 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. In addition, gross G&A and capitalized G&A decreased due to lower employee compensation and benefits resulting from our 2010 offshore divestitures, 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

The following schedule includes the components of restructuring costs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Cash severance	$ (13)	$	$ (18)	$
Share-based awards	(5)		(9)	
Lease obligations	70		70	
Asset impairments	11		11	
Other			1	
Total	$ 63	$	$ 55	$

Employee Severance

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 and a significant part of our International assets by the end of the third quarter of 2010. As a result of these divestitures and associated employee terminations, we decreased our estimate of employee severance costs in the second and third quarters of 2010 by $14 million and $21 million, respectively. As a result, we now estimate we will incur approximately $118 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 $118 million total, $78 million relates to our U.S. Offshore operations and the remainder relates to our International discontinued operations. Of the $14 million and $21 million reductions recognized during in the second and third quarters of 2010, $9 million and $18 million, respectively, relate to our U.S. Offshore operations and the remainders relate to our International discontinued operations.

Lease Obligations

As a result of the divestitures discussed above, we ceased using certain office space that was subject to non-cancellable operating lease arrangements. Consequently, in the third quarter of 2010, we recognized $70 million of restructuring costs that represent the present value of our future obligations under the leases, net of anticipated sublease income. Our estimate of lease obligations was based upon certain key estimates that could change over the term of the leases. These estimates include the estimated sublease income that we may receive over the term of the leases, as well as the amount of variable operating costs that we will be required to pay under the leases.

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Asset Impairments

In the third quarter of 2010, we recognized $11 million of asset impairment charges for leasehold improvements and furniture associated with the office space we ceased using.

Interest Expense

The following schedule includes the components of interest expense.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Interest based on debt outstanding	$ 98	$ 112	$ 307	$ 330
Capitalized interest	(20)	(22)	(55)	(71)
Early retirement of debt			19	
Other	5		9	4
Total	$ 83	$ 90	$ 280	$ 263

Interest based on debt outstanding decreased during the third quarter and first nine months of 2010 primarily due to the retirement of $177 million of 10.125% notes upon their maturity in the fourth quarter of 2009 and the early redemption of our 7.25% senior notes as discussed below.

Capitalized interest decreased during the third quarter and first nine months of 2010 primarily due to the divestitures of our U.S. Offshore properties during the first half of 2010, which was partially offset by higher capitalized interest associated with our Canadian oil sands development projects.

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.

Interest-Rate and Other Financial Instruments

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
(Gains) losses from interest rate swaps:				
Cash settlements	$ (17)	$ (14)	$ (37)	$ (35)
Unrealized fair value changes	72	9	158	15
Total	$ 55	$ (5)	$ 121	$ (20)

During the third quarter and first nine months of 2010, we received cash settlements totaling $17 million and $37 million, respectively, from counterparties to settle our interest rate swaps. During the third quarter and first nine months of 2009, we received cash settlements totaling $14 million and $35 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 September 30, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $63 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 September 30, 2010.

Including the cash settlements discussed above, the net losses from our interest rate swaps were $55 million and $121 million during the third quarter and first nine months of 2010, respectively. Including the cash settlements discussed above, the net gains from our interest rate swaps were $5 million and $20 million during the third quarter and first nine months 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 third 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.

Other, net

The following schedule includes the components of other, net.

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In millions)			
Interest and dividend income	$ (4)	$ (2)	$ (9)	$ (3)
Deep water royalties		(84)		(84)
Other	(4)	(6)	(25)	26
Total	$ (8)	$ (92)	$ (34)	$ (61)

In 1995, the United States Congress passed the Deep Water Royalty Relief Act. The intent of this legislation was to encourage deep water exploration in the Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. Deep water leases issued in certain years by the Minerals Management Service (the MMS) have contained price thresholds, such that if the market prices for oil or gas exceeded the thresholds for a given year, royalty relief would not be granted for that year.

In October 2007, a federal district court ruled in favor of a plaintiff who had challenged the legality of including price thresholds in deep water leases. Additionally, in January 2009 a federal appellate court upheld this district court ruling. This judgment was later appealed to the United States Supreme Court, which, in October 2009, declined to review the appellate court s ruling. The Supreme Court s decision ended the MMS s judicial course to enforce the price thresholds.

Prior to September 30, 2009, we had $84 million accrued for potential royalties on various deep water leases. Based upon the Supreme Court s decision, we reduced to zero the $84 million loss contingency accrual in the third quarter of 2009.

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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Total income tax expense (benefit) (In millions)	$ 270	$ 89	$ 1,045	$ (2,082)
U.S. statutory income tax rate	35%	35%	35%	(35%)
U.S. taxes on foreign earnings	3%		2%	
Prior year tax return filings		(13%)		(1%)
State income taxes	1%	1%	1%	(1%)
Taxation on Canadian operations	(1%)		(1%)	
Other	1%	(4%)	(1%)	(2%)
Effective income tax (benefit) rate	39%	19%	36%	(39%)

In the second and third quarters of 2010, we recognized $52 million and $23 million, respectively, 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.

In the third quarter of 2009, we recognized $59 million of income tax benefits in conjunction with the initial or amended filings of our 2005, 2006, 2007 and 2008 income tax returns. These tax benefits consist of deferred tax benefits of $50 million and current tax benefits of $9 million. Of the $59 million, $41 million relates to taxation on foreign operations. The remaining $18 million relates to taxation on U.S. federal and state operations.

Our 2010 Gulf of Mexico divestitures have taxable gains that increase our current income tax expense by $858 million. However, the additional current income taxes are offset by a decrease in deferred income tax expense, resulting in no impact to our total income tax expense.

Additionally, in conjunction with the filing of our 2009 income tax return in the third quarter of 2010, we recognized a $220 million decrease to current income tax expense that was offset by a like increase to deferred income tax expense. These amounts relate to a change in the timing of certain deductions, which we decided to expense rather than capitalize for the 2009 tax year. Such deductions created a net operating loss for the 2009 tax year that we are using to reduce our 2010 current income taxes that would otherwise be due as a result of the taxable divestiture gains mentioned above.

Earnings from Discontinued Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Total production (MMBoe)	2	4	8	12
Combined price without hedges (per Boe)	$ 67.55	$ 65.42	$ 72.01	$ 54.85
	(In millions)			
Operating revenues	$ 139	$ 250	$ 573	$ 646
Expenses and other, net:				
Operating expenses	39	132	168	364
Reduction of carrying value of oil and gas properties				109

Gain on sale of oil and gas properties	(1,535)		(1,843)	
Other, net	(75)	(3)	(72)	(25)
Total expenses and other, net	(1,571)	129	(1,747)	448
Earnings before income taxes	1,710	121	2,320	198
Income tax expense	49	4	187	34
Earnings from discontinued operations	$ 1,661	$ 117	$ 2,133	$ 164

Earnings increased $1.5 billion in the third quarter of 2010 primarily as a result of the $1.5 billion gain ($1.5 billion after taxes) from the divestiture of our Azerbaijan operations.

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Earnings increased $2.0 billion in the first nine months of 2010 primarily as a result of the $1.5 billion gain ($1.5 billion after taxes) from the divestiture of our Azerbaijan operations and the $308 million gain ($235 million after taxes) from the divestiture of our Panyu operations in China. Also, earnings increased $109 million due to the 2009 reductions of 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.

Earnings in both the third quarter and first nine months of 2010 also decreased due to production declines, resulting from the 2010 asset divestitures.

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

	Nine Months Ended September 30,	
	2010	**2009**
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 3,912	$ 2,935
Divestitures of property and equipment	4,131	23
Cash distributed from discontinued operations	2,824	6
Commercial paper borrowings		1,368
Debt issuance, net of commercial paper repayments		182
Redemptions of long-term investments	20	6
Stock option exercises	18	19
Other	7	6
Total sources of cash and cash equivalents	**10,912**	**4,545**
Uses of cash and cash equivalents:		
Capital expenditures	(4,793)	(3,807)
Commercial paper repayments	(1,432)	
Repurchases of common stock	(929)	
Debt repayments	(350)	(1)
Dividends	(211)	(213)
Other	(13)	
Total uses of cash and cash equivalents	**(7,728)**	**(4,021)**
Increase from continuing operations	3,184	524
Decrease from discontinued operations, including distributions to continuing operations	(202)	(25)
Effect of foreign exchange rates	5	29
Net increase in cash and cash equivalents	**$ 2,987**	**$ 528**
Cash and cash equivalents at end of period	**$ 3,998**	**$ 912**

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 nine 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 33% in 2010 primarily due to the increase in revenues as discussed in the Results of Operations section of this report.

During the first nine months of 2010, our operating cash flow funded approximately 82% of our cash payments for capital expenditures. However, our capital expenditures for the first nine months 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 over 90% of our capital expenditures during the first nine months of 2010.

During the first nine months of 2009, our operating cash flow funded approximately 77% 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 nine months of 2010, we completed the divestiture of our U.S. Offshore, Azerbaijan and China properties, generating $6.6 billion in pre-tax proceeds net of closing adjustments, or $5.6 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 $1.4 billion to fund capital expenditures in excess of our operating cash flow.

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 nine months of 2010 and 2009 were approximately $5.0 billion and $3.3 billion, respectively.

	Nine Months Ended September 30,	
	2010	2009
	(In millions)	
U.S. Onshore	$ 2,564	$ 2,043
Canada	1,438	747
North America Onshore	4,002	2,790
U.S. Offshore	365	704
Total exploration and development	4,367	3,494
Midstream	176	230
Other	250	83
Total continuing operations	$ 4,793	$ 3,807

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 $4.4 billion and $3.5 billion in the first nine months of 2010 and 2009, respectively. The increase in exploration and development capital spending in the first nine months of 2010 was partially due to the $500 million Pike oil sands acquisition mentioned above. Additionally, with rising oil and NGL prices and proceeds from our offshore divestiture program, we are increasing drilling primarily to grow liquids 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 dry gas drilling activities.

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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 nine 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 had repurchased 14.7 million common shares for $936 million, or $63.61 per share through September 2010.

Dividends

Our common stock dividends were $211 million and $213 million (quarterly rates of $0.16 per share) in the first nine 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 29% to $4.2 billion in the first nine 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, 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 September 30, 2010, approximately 61% of our estimated 2010 gas production and 70% of our estimated oil production are subject to either price collars, swaps or fixed-price contracts.

Looking beyond 2010, we have also entered into contracts to manage the price risk relative to our 2011 and 2012 oil and gas production. A summary of these contracts as of the end of the third quarter of 2010 is included in Item 3. Quantitative and Qualitative Disclosures About Market Risk of this report.

Offshore Divestitures

During 2010, another major source of liquidity are proceeds generated from divestitures of our offshore assets. In the first nine months of 2010, we completed our exit from the Gulf of Mexico and divested our assets in Azerbaijan and China, generating total after-tax proceeds of $5.6 billion. Additionally, we have entered into an agreement to sell our assets in Brazil for $3.2 billion. 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. The divestiture process is ongoing for our exploration assets in Angola.

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.

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.

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 September 30, 2010, we had $2.6 billion of available capacity under our syndicated, unsecured Senior Credit Facility 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 Senior Credit Facility by maturity date, as well as our available capacity as of September 30, 2010 (in millions).

April 7, 2012 maturity	$ 463
April 7, 2013 maturity	2,187
Total Senior Credit Facility	2,650
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	37
Total available capacity	$ 2,613

As noted in the table above, we had no short-term borrowings as of September 30, 2010 or during the third quarter of 2010. Our weighted average short-term borrowings for the first nine months of 2010 were $0.3 billion.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders equity adjusted for noncash financial writedowns, such as full cost ceiling impairments. As of September 30, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at September 30, 2010, as calculated pursuant to the terms of the agreement, was 15.3%.

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 of the associated properties in the first nine months 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.

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

Commodity Price Risk

We have commodity derivatives that pertain to production for the remainder of 2010, as well as 2011 and 2012. The key terms to our oil, gas and NGL derivatives as of September 30, 2010 are presented in the following tables.

Gas Price Swaps

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Fourth quarter 2010	1,265,000	$ 6.16
Total year 2011	525,000	$ 5.56

Gas Price Collars

		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
Fourth quarter 2010	355,000	$ 4.50 - $5.50	$ 4.85	$ 5.40 - $7.10	$ 6.12

Gas Basis Swaps

Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Fourth quarter 2010	AECO	150,000	$ 0.33
Fourth quarter 2010	CIG	70,000	$ 0.37
Total year 2011	Panhandle Eastern Pipeline	135,000	$ 0.34

Gas Call Options Sold

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Total year 2012	300,000	$ 6.00

Oil Price Collars

		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
Fourth quarter 2010	79,000	$ 65.00 - $70.00	$ 67.47	$ 90.35 - $103.30	$ 96.48
Total year 2011	33,000	$ 75.00 - $75.00	$ 75.00	$ 105.00 - $116.10	$ 109.00

Oil Call Options Sold

Period	Volume (Bbls /d)	Weighted Average Price ($/Bbl)

Total year 2011	12,000	$	95.00
Total year 2012	12,000	$	95.00

NGL Basis Swaps

Period	Volume (Bbls/d)	Pay Natural Gasoline ($/Bbl)	Receive Oil ($/Bbl)
Total year 2011	500	$ 70.77	$ 80.52
Total year 2012	500	$ 71.82	$ 81.92

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 September 30, 2010, a 10% increase in the forward curves associated with our

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gas price swaps and collars would have decreased the fair value of such instruments by approximately $163 million. A 10% increase in the forward curves associated with our oil collars would have decreased the fair value of such instruments by approximately $95 million.

Interest Rate Risk

At September 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 September 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
$ 950	3.92%	Three month LIBOR	September 30, 2011

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds Rate and LIBOR. At September 30, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $63 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 September 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 September 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 third quarter of 2010 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

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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)
July	4,284,300	$	62.07	4,284,300	$	2,739
August	1,442,100	$	61.30	1,442,100	$	2,651
September	1,377,600	$	62.80	1,377,600	$	2,564
Total	7,104,000	$	62.05	7,104,000		

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011. As of September 30, 2010, we have repurchased 14.7 million common shares for $936 million, or $63.61 per share under this program.

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.
32.2	

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DEVON ENERGY CORPORATION

Date: November 4, 2010

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

INDEX TO EXHIBITS

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.
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