DEVON ENERGY CORP/DE
Form 10-Q
November 05, 2009

Table of Contents

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, 2009

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 November 2, 2009, 444.1 million shares of common stock were outstanding.

Table of Contents

[This page intentionally left blank.]

DEVON ENERGY CORPORATION
FORM 10-Q
For the Quarterly Period Ended September 30, 2009
INDEX

Table of Contents

DEFINITIONS

As used in this document:

Bbl or Bbls means barrel or barrels.

Bcf means billion cubic feet.

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

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

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

Domestic means the operations of Devon encompassing oil and gas properties in the onshore continental United States and the offshore Gulf of Mexico.

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*.

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

LIBOR means London Interbank Offered Rate.

Mcf means thousand cubic feet.

MMBbls means million barrels.

MMBoe means million Boe.

MMBtu means million Btu.

NGL or NGLs means natural gas liquids.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

SEC means United States Securities and Exchange Commission.

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

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

Table of Contents

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, 2008 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;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations;

- terrorism;
- occurrence of property acquisitions or divestitures; and
- other factors disclosed in our 2008 Annual Report on Form 10-K 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.

Table of Contents

PART I. Financial Information

Item 1. Consolidated Financial Statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	September 30, 2009 (Unaudited)	December 31, 2008
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 905	$ 379
Accounts receivable	1,142	1,412
Income taxes receivable	47	334
Derivative financial instruments, at fair value	131	282
Other current assets	384	277
Total current assets	2,609	2,684
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($4,433 million and $4,551 million excluded from amortization in 2009 and 2008, respectively)	61,375	55,664
Less accumulated depreciation, depletion and amortization	42,503	32,683
Property and equipment, net	18,872	22,981
Goodwill	5,929	5,579
Other long-term assets, including $167 million and $199 million at fair value in 2009 and 2008, respectively	731	664
Total assets	$ 28,141	$ 31,908
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,113	$ 1,825
Revenues and royalties due to others	368	496
Short-term debt	1,545	180
Current portion of asset retirement obligations, at fair value	108	138
Other current liabilities, including $7 million at fair value in 2009	309	496
Total current liabilities	3,443	3,135
Long-term debt	5,848	5,661
Asset retirement obligations, at fair value	1,511	1,347
Other long-term liabilities	977	1,026
Deferred income taxes	1,709	3,679
Stockholders equity:		

Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 444.1 million and 443.7 million shares in 2009 and 2008, respectively	44	44
Additional paid-in capital	6,410	6,257
Retained earnings	7,017	10,376
Accumulated other comprehensive income	1,182	383
Total stockholders equity	14,653	17,060
Commitments and contingencies (Note 11)		
Total liabilities and stockholders equity	$ 28,141	$ 31,908

See accompanying notes to consolidated financial statements.

6

Table of Contents

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil sales	$ 845	$ 1,296	$ 2,107	$ 4,001
Gas sales	691	2,107	2,344	5,947
NGL sales	195	362	501	1,069
Net gain (loss) on oil and gas derivative financial instruments	23	1,592	190	(411)
Marketing and midstream revenues	344	621	1,074	1,895
Total revenues	2,098	5,978	6,216	12,501
Expenses and other income, net:				
Lease operating expenses	505	591	1,539	1,634
Production taxes	61	152	150	462
Marketing and midstream operating costs and expenses	244	452	707	1,349
Depreciation, depletion and amortization of oil and gas properties	480	781	1,573	2,280
Depreciation and amortization of non-oil and gas properties	65	67	209	186
Accretion of asset retirement obligations	25	22	73	66
General and administrative expenses	137	146	485	474
Interest expense	90	69	263	261
Change in fair value of other financial instruments	(5)	46	(20)	22
Reduction of carrying value of oil and gas properties			6,516	
Other income, net	(96)	(83)	(69)	(121)
Total expenses and other income, net	1,506	2,243	11,426	6,613
Earnings (loss) from continuing operations before income taxes	592	3,735	(5,210)	5,888
Income tax expense (benefit):				
Current	102	226	155	743
Deferred	(9)	1,000	(2,203)	1,391
Total income tax expense (benefit)	93	1,226	(2,048)	2,134
Earnings (loss) from continuing operations	499	2,509	(3,162)	3,754
Discontinued operations:				
Earnings from discontinued operations before income taxes		93	16	1,133
Discontinued operations income tax expense (benefit)		(16)		219

Earnings from discontinued operations		109	16	914
Net earnings (loss)	499	2,618	(3,146)	4,668
Preferred stock dividends				5
Net earnings (loss) applicable to common stockholders	$ 499	$ 2,618	$ (3,146)	$ 4,663
Basic net earnings (loss) per share:				
Basic earnings (loss) from continuing operations per share	$ 1.13	$ 5.68	$ (7.12)	$ 8.45
Basic earnings (loss) from discontinued operations per share		0.25	0.03	2.05
Basic net earnings (loss) per share	$ 1.13	$ 5.93	$ (7.09)	$ 10.50
Diluted net earnings (loss) per share:				
Diluted earnings (loss) from continuing operations per share	$ 1.12	$ 5.64	$ (7.12)	$ 8.37
Diluted earnings (loss) from discontinued operations per share		0.24	0.03	2.03
Diluted net earnings (loss) per share	$ 1.12	$ 5.88	$ (7.09)	$ 10.40

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(Unaudited) (In millions)			
Net earnings (loss)	$ 499	$ 2,618	$ (3,146)	$ 4,668
Foreign currency translation:				
Change in cumulative translation adjustment	520	(386)	826	(679)
Foreign currency translation income tax benefit (expense)	(31)	15	(50)	29
Foreign currency translation total	489	(371)	776	(650)
Pension and postretirement benefit plans:				
Recognition of net actuarial loss and prior service cost in net earnings (loss)	12	4	36	12
Pension and postretirement benefit plans income tax benefit (expense)	(5)	(2)	(13)	(5)
Pension and postretirement benefit plans total	7	2	23	7
Other comprehensive earnings (loss), net of tax	496	(369)	799	(643)
Comprehensive income (loss)	$ 995	$ 2,249	$ (2,347)	$ 4,025

See accompanying notes to consolidated financial statements.

Table of Contents

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Preferred Stock	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders Equity
					(Unaudited) (In millions)			
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
Nine Months Ended September 30, 2008:								
Balance as of December 31, 2007	$ 1	444	$ 44	$ 6,743	$ 12,813	$ 2,405	$	$ 22,006
Net earnings (loss)					4,668			4,668
Other comprehensive earnings (loss), net of tax						(643)		(643)
Stock option exercises		4	1	112			(4)	109

Common stock repurchased							(681)	(681)
Common stock retired		(7)	(1)	(684)			685	
Redemption of preferred stock	(1)			(149)				(150)
Common stock dividends					(211)			(211)
Preferred stock dividends					(5)			(5)
Share-based compensation				139				139
Share-based compensation tax benefits				58				58
Balance as of September 30, 2008	$	441	$ 44	$ 6,219	$ 17,265	$ 1,762	$	$ 25,290

See accompanying notes to consolidated financial statements.

Table of Contents

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2009	2008
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net earnings (loss)	$ (3,146)	$ 4,668
Net loss (earnings) from discontinued operations	(16)	(914)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,782	2,466
Deferred income tax expense (benefit)	(2,203)	1,391
Reduction of carrying value of oil and gas properties	6,516	
Net unrealized loss (gain) on oil and gas derivative financial instruments	169	(140)
Other noncash charges	199	217
Net decrease (increase) in working capital	(1)	339
Decrease (increase) in long-term other assets	20	(61)
Increase (decrease) in long-term other liabilities	(33)	94
Cash provided by operating activities continuing operations	3,287	8,060
Cash provided by operating activities discontinued operations	5	121
Net cash provided by operating activities	3,292	8,181
Cash flows from investing activities:		
Proceeds from sales of property and equipment	23	116
Capital expenditures	(4,184)	(6,184)
Purchases of short-term investments		(50)
Sales of long-term and short-term investments	6	297
Cash used in investing activities continuing operations	(4,155)	(5,821)
Cash provided by investing activities discontinued operations	1	1,859
Net cash used in investing activities	(4,154)	(3,962)
Cash flows from financing activities:		
Proceeds from borrowings of long-term debt, net of issuance costs	1,187	
Credit facility repayments		(3,191)
Credit facility borrowings		1,741
Net commercial paper borrowings (repayments)	363	(1,004)
Debt repayments	(1)	(1,031)
Redemption of preferred stock		(150)
Proceeds from stock option exercises	19	109
Repurchases of common stock		(665)

Dividends paid on common and preferred stock	(213)	(216)
Excess tax benefits related to share-based compensation	6	58
Net cash provided by (used in) financing activities	1,361	(4,349)
Effect of exchange rate changes on cash	29	(47)
Net increase (decrease) in cash and cash equivalents	528	(177)
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	384	1,373
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 912	$ 1,196

See accompanying notes to consolidated financial statements.

Table of Contents

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 2008 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, 2009 and Devon s results of operations and cash flows for the three-month and nine-month periods ended September 30, 2009 and 2008. To prepare the accompanying financial statements and notes, Devon s management evaluated events or transactions that occurred subsequent to September 30, 2009 and before November 5, 2009, which was the date these financial statements were issued.

Recently Issued Accounting Standards Not Yet Adopted

In December 2008, the Financial Accounting Standards Board (FASB) updated Accounting Standards Codification (ASC) Topic 715 Compensation Retirement Benefits, regarding employers disclosures about postretirement benefit plan assets. This ASC update requires additional disclosures about the types of assets and associated risks in an employer s defined benefit pension or other postretirement plan. It is effective for fiscal years ending after December 15, 2009. Devon is evaluating the impact the adoption of this ASC update will have on its financial statement disclosures. However, Devon s adoption of this ASC update will not affect its current accounting for its pension and postretirement plans.

Modernization of Oil and Gas Reporting

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. Additionally, on two separate occasions in October 2009, the SEC issued certain compliance and disclosure interpretations of its oil and gas rules. The disclosure revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting Devon s reserve disclosures, including the comparability of its reserves disclosures with those of its peer companies:

Pricing mechanism for oil and gas reserves estimation The SEC s current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

Reasonable certainty The SEC s current definition of proved oil and gas reserves incorporate certain specific concepts such as lowest known hydrocarbons, which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

Table of Contents

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

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of reliable technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, Devon expects its proved reserve estimates will increase upon adoption of the revised rules. However, Devon is not able to estimate the magnitude of the potential increase at this time.

Unproved reserves The SEC s current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. Devon has not yet determined whether it will disclose its probable and possible reserves in documents filed with the SEC.

2. Accounts Receivable

The components of accounts receivable include the following:

	September 30, 2009	December 31, 2008
	(In millions)	
Oil, gas and NGL revenues	$ 595	$ 789
Joint interest billings	222	263
Marketing and midstream revenues	114	153
Production tax credits	197	170
Other	25	42
Gross accounts receivable	1,153	1,417
Allowance for doubtful accounts	(11)	(5)
Net accounts receivable	$ 1,142	$ 1,412

3. Derivative Financial Instruments

Devon periodically enters into commodity and interest rate derivative financial instruments. These instruments are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility and to manage Devon s exposure to interest rate volatility. Also, during the first eight months of 2008, Devon was subject to an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock.

Table of Contents

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

The following table presents the fair values of derivative assets and liabilities included in the accompanying balance sheets. None of Devon s derivative instruments included in the table have been designated as hedging instruments.

	Balance Sheet Caption	Asset	Liability
		(In millions)	
September 30, 2009:			
Gas price collars	Derivative financial instruments, current	$ 86	$
Gas price swaps	Other current liabilities		7
Oil price collars	Derivative financial instruments, current	7	
Interest rate swaps	Derivative financial instruments, current	38	
Interest rate swaps	Other long-term assets	51	
Total derivatives		$ 182	$ 7
December 31, 2008:			
Gas price collars	Derivative financial instruments, current	$ 255	$
Interest rate swaps	Derivative financial instruments, current	27	
Interest rate swaps	Other long-term assets	77	
Total derivatives		$ 359	$

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying statements of operations associated with these derivative financial instruments. None of Devon s derivative instruments included in the table have been designated as hedging instruments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Cash settlement receipts (payments):				
Gas price collars (1)	$ 118	$ (125)	$ 350	$ (275)
Gas price swaps (1)	9	(115)	9	(276)
Interest rate swaps (2)	14		35	
Total cash settlements	141	(240)	394	(551)
Unrealized gains (losses):				
Gas price collars (1)	(104)	1,142	(169)	114
Gas price swaps (1)	(7)	645	(7)	27
Oil price collars (1)	7	45	7	(1)
Interest rate swaps (2)	(9)	23	(15)	23
Embedded option (2)		167		109

Total unrealized gains (losses)	(113)	2,022	(184)	272
Net gain (loss) recognized on statement of operations	$ 28	$ 1,782	$ 210	$ (279)

(1) Cash settlements and unrealized gains and losses on fair value changes associated with Devon s gas price collars, gas price swaps and oil price collars have been recorded in the Net gain (loss) on oil and gas derivative financial instruments line item in the accompanying statements of operations.

(2) Cash settlements and unrealized gains and losses on fair value changes associated with Devon s interest rate swaps and embedded option have been recorded in the Change in fair value of other financial instruments line item in the accompanying statements of operations.

Table of Contents

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

4. Other Current Assets

The components of other current assets include the following:

	September 30, 2009	December 31, 2008
	(In millions)	
Inventories	$ 278	$ 197
Prepaid assets	71	49
Other	35	31
Other current assets	$ 384	$ 277

5. Property and Equipment

In the first quarter of 2009, Devon reduced the carrying values of certain of its oil and gas properties due to full cost ceiling limitations. These reductions are discussed in Note 14.

6. Goodwill

During the first nine months of 2009, Devon s goodwill increased $350 million. This increase related to Devon s Canadian goodwill and was entirely due to foreign currency translation.

7. Debt

5.625% Senior Notes Due January 15, 2014 and 6.30% Senior Notes Due January 15, 2019

In January 2009, Devon 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.

Credit Lines

Devon has two syndicated, unsecured revolving lines of credit that can be accessed to provide liquidity as needed. The following schedule summarizes the capacity of Devon s credit facilities by maturity date, as well as its available capacity as of September 30, 2009.

Description	Amount (In millions)
Senior Credit Facility maturities:	
April 7, 2012	$ 500
April 7, 2013	2,150
Senior Credit Facility total capacity	2,650
Short-Term Facility total capacity November 2, 2010 maturity	700
Total credit facility capacity	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	1,368
Outstanding letters of credit	84
Total available capacity	$ 1,898

On November 3, 2009 Devon s unused $700 million short-term facility matured. On November 3, 2009, Devon established a new $700 million 364-day, syndicated, unsecured revolving senior credit facility (the Short-Term Facility). The Short-Term Facility matures on November 2, 2010. On the maturity date, all amounts outstanding will be due and payable at that time. Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods

14

of up to 12 months. Such rates are generally based on LIBOR or the prime rate. The Short-Term Facility provides for an annual facility fee of approximately $1.75 million that is payable quarterly in arrears.

The credit facilities contain 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, 2009, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at September 30, 2009, as calculated pursuant to the terms of the agreement, was 21.3%.

Commercial Paper

Subsequent to the $1.0 billion commercial paper repayment in January 2009, Devon utilized additional net commercial paper borrowings of $1.4 billion to fund capital expenditure payments in excess of cash generated by operating activities during the first nine months of 2009. As of September 30, 2009, Devon s average borrowing rate on its $1.4 billion of commercial paper debt was 0.32%.

8. Asset Retirement Obligations

The following is a summary of the changes in Devon s asset retirement obligations (ARO) for the first nine months of 2009 and 2008.

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In millions)	
ARO as of beginning of period	$ 1,485	$ 1,318
Liabilities incurred	32	48
Liabilities settled	(76)	(59)
Revisions, net	23	244
Accretion expense on discounted obligation	73	66
Foreign currency translation adjustment	82	(46)
ARO as of end of period	1,619	1,571
Less current portion	108	115
ARO, long-term	$ 1,511	$ 1,456

9. Retirement Plans

Net Periodic Benefit Cost and Other Comprehensive Income

The following table presents the components of net periodic benefit cost and other comprehensive income for Devon s pension and other post retirement benefit plans for the three-month and nine-month periods ended September 30, 2009 and 2008.

Table of Contents

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

	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,	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Net periodic benefit cost:								
Service cost	$ 11	$ 10	$ 33	$ 30	$	$	$	$
Interest cost	14	14	42	42	1	2	3	6
Expected return on plan assets	(9)	(13)	(27)	(39)				
Amortization of prior service cost	1		3					
Net actuarial loss	11	4	33	12				
Net periodic benefit cost	28	15	84	45	1	2	3	6
Other comprehensive income:								
Recognition of prior service cost in net periodic benefit cost	(1)		(3)					
Recognition of net actuarial loss in net periodic benefit cost	(11)	(4)	(33)	(12)				
Total recognized	$ 16	$ 11	$ 48	$ 33	$ 1	$ 2	$ 3	$ 6

Devon previously disclosed in its 2008 Annual Report on Form 10-K that it expected to contribute up to approximately $183 million to its defined benefit pension plans in 2009 and $5 million to its defined benefit postretirement plans in 2009. Devon has revised its estimate of 2009 defined benefit pension plan contributions to $55 million. As of September 30, 2009, Devon has contributed $42 million to its defined benefit pension plans and $3 million to its defined benefit postretirement plans.

10. Stockholders Equity

Stock Repurchases

During the first nine months of 2008, Devon repurchased 6.5 million common shares for $665 million, or $102.56 per share, under programs approved by its Board of Directors. The 6.5 million common shares include 4.5 million shares that were repurchased under Devon s 50 million share repurchase program and 2.0 million shares that were repurchased under Devon s ongoing, annual stock repurchase program. No such repurchases were made during the first nine months of 2009.

Dividends

Devon paid common stock dividends of $213 million and $211 million (quarterly rates of $0.16 per share) in the first nine months of 2009 and 2008, respectively. Devon paid preferred stock dividends of $5 million in 2008. Devon redeemed all 1.5 million outstanding shares of its preferred stock on June 20, 2008.

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.

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

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 (CERCLA) and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon s consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon s subsidiaries are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties (PRPs) under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of September 30, 2009, Devon s balance sheet included $1 million of accrued liabilities, reflected in other long-term liabilities, related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon s conclusion is based in large part on (i) Devon s participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis* PRP, and (iii) the availability of other defenses to liability. As a result, Devon s monetary exposure 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. The principal suit in which Devon is a defendant is *United States ex rel. Wright v. Chevron USA, Inc. et al.* (the Wright case). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the Wright case back to the Eastern District of Texas to resume proceedings. On April 12, 2007, the court entered a trial plan and scheduling order in which the case will proceed in phases. Two phases have been scheduled to date. The first phase was scheduled to begin in August 2008, but the defendant settled prior to trial. The second phase was scheduled to begin in February 2009, but the defendants settled prior to trial. Devon was not included in the groups of defendants selected for these first two phases. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure with respect to this lawsuit. Therefore, no liability related to this lawsuit has been recorded.

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.

Table of Contents

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

Prior to September 30, 2009, Devon had $84 million accrued for potential royalties on various deep water leases. Based upon the Supreme Court s decision, Devon reduced to zero the $84 million loss contingency accrual in the third quarter of 2009. The $84 million expense reduction is included in other income in the accompanying 2009 statements of operations.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon s knowledge as of the date these financial statements were issued, neither Devon nor its property is subject to any material pending legal proceedings.

12. Fair Value Measurements

Certain of Devon s assets and liabilities are reported at fair value in the accompanying balance sheets. Such assets and liabilities include amounts for both financial and nonfinancial instruments. The following tables provide carrying value and fair value measurement information for such assets and liabilities as of September 30, 2009 and December 31, 2008.

	As of September 30, 2009				
			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)		
Financial Assets (Liabilities):					
Long-term investments	$ 116	$ 116	$	$	$ 116
Gas price collars	$ 86	$ 86	$	$ 86	$
Gas price swaps	$ (7)	$ (7)	$	$ (7)	$
Oil price collars	$ 7	$ 7	$	$ 7	$
Interest rate swaps	$ 89	$ 89	$	$ 89	$
Debt	$(7,393)	$(8,269)	$(1,368)	$(6,901)	$
Asset retirement obligations	$(1,619)	$(1,619)	$	$	$ (1,619)

	As of December 31, 2008				
			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)		
Financial Assets (Liabilities):					
Long-term investments	$ 122	$ 122	$	$	$ 122
Gas price collars	$ 255	$ 255	$	$ 255	$
Interest rate swaps	$ 104	$ 104	$	$ 104	$
Debt	$(5,841)	$(6,106)	$(1,005)	$(5,101)	$
Asset retirement obligations	$(1,485)	$(1,485)	$	$	$ (1,485)

Table of Contents

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

A summary of the changes in Devon s asset retirement obligations during the first nine months of 2009 is included in Note 8. Included below is a summary of the changes in Devon s other Level 3 fair value measurements during the first nine months of 2009 (in millions).

Beginning balance	$ 122
Redemptions of principal at par	(6)
Ending balance	$ 116

13. Change in Fair Value of Other Financial Instruments

The components of the change in fair value of other financial instruments are presented in the following table.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
(Gains) losses from:				
Interest rate swaps settlements	$ (14)	$	$ (35)	$
Interest rate swaps fair value changes	9	(23)	15	(23)
Chevron common stock		236		154
Option embedded in exchangeable debentures		(167)		(109)
Total	$ (5)	$ 46	$ (20)	$ 22

14. Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, Devon reduced the carrying values of certain of its oil and gas properties due to full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

	March 31, 2009	
	Gross	Net of Taxes
	(In millions)	
United States	$ 6,408	$ 4,085
Brazil	103	103
Russia	5	2
Total	$ 6,516	$ 4,190

The United States reduction resulted primarily from a significant decrease in the full cost ceiling during the first three months of 2009. The lower ceiling value in the United States largely resulted from the continued effects of declining natural gas prices subsequent to December 31, 2008.

Although oil prices improved subsequent to December 31, 2008, Brazil s 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, 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.

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

To demonstrate the changes in the full-cost ceiling for the United States and Brazil, the March 31, 2009 and December 31, 2008 weighted average wellhead prices are presented in the following table.

	March 31, 2009			December 31, 2008		
	Oil	Gas	NGLs	Oil	Gas	NGLs
Country	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Bbl)	(Per Mcf)	(Per Bbl)
United States	$47.30	$2.67	$17.04	$42.21	$4.68	$16.16
Brazil	$36.71	N/A	N/A	$26.61	N/A	N/A

N/A Not applicable.

The March 31, 2009 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $49.66 per Bbl for crude oil and the Henry Hub spot price of $3.63 per MMBtu for gas. The December 31, 2008 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas.

15. Other Income

The components of other income are presented in the following table.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Interest and dividend income	$ 3	$ 18	$ 7	$ 65
Deep water royalties (see Note 11)	84		84	
Hurricane insurance proceeds		57		57
Other	9	8	(22)	(1)
Total	$ 96	$ 83	$ 69	$ 121

16. Income Taxes

In the third quarter of 2009, Devon recognized $59 million of income tax benefits in conjunction with the filing of its 2008 and certain amended 2005, 2006 and 2007 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.

Also in the third quarter of 2009, Devon recognized a $22 million current tax benefit related to certain unsuccessful international drilling results.

17. Discontinued Operations

At the end of 2008, Devon s operations in Angola were classified as discontinued as a result of Devon s plans and ongoing activities to sell its operations in Angola. Due to a commercial discovery in the second quarter of 2009, Devon suspended marketing its Angolan operations for sale. Although Devon intends to resume marketing activities in 2010 once it has drilled its remaining commitment wells, Devon s operations in Angola do not currently qualify as discontinued. Therefore, Devon has classified all amounts related to its Angolan operations for 2009 and prior years as continuing operations.

In the second quarter of 2008, Devon sold its assets and terminated its operations in certain West African countries, consisting primarily of Equatorial Guinea and Gabon. As a result of the sales, Devon recognized gains totaling

$736 million ($647 million after taxes) in the second quarter of 2008 from proceeds of $2.4 billion ($1.7 billion net of income taxes and purchase price adjustments).

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

In the third quarter of 2008, Devon sold its assets and terminated its operations in Cote d Ivoire. As a result of this sale, Devon recognized a gain of $83 million ($101 million after tax) in the third quarter of 2008 from proceeds of $205 million ($163 million net of purchase price adjustments).

In the second quarter of 2009, Devon recognized a $17 million gain in conjunction with post-closing settlements related to the 2008 sales.

Operating revenues related to Devon s discontinued operations totaled $17 million and $349 million in the three-month and nine-month periods ended September 30, 2008, respectively. There were no operating revenues related to Devon s discontinued operations for the three-month and nine-month periods ended September 30, 2009.

The following table presents the main classes of assets and liabilities associated with Devon s discontinued operations as of September 30, 2009 and December 31, 2008.

	Devon s Consolidated Balance Sheet Caption	September 30, 2009	December 31, 2008
		(In millions)	
Cash and other current assets	Other current assets	$16	$ 14
Property and equipment, net of accumulated depreciation, depletion and amortization	Other long-term assets	$ 9	$ 9
Accounts payable and other current liabilities	Other current liabilities	$10	$ 6

18. 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, 2009 and 2008. 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 from continuing operations in the nine months ended September 30, 2009 reported in the accompanying 2009 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, 2009:			
Earnings from continuing operations	$ 499	444	
Attributable to participating securities	(5)	(5)	
Basic earnings per share	494	439	$ 1.13
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 494	441	$ 1.12
Three Months Ended September 30, 2008:			
Earnings from continuing operations	$ 2,509	442	
Attributable to participating securities	(23)	(4)	

Basic earnings per share	2,486	438	$ 5.68
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		3	
Diluted earnings per share	$ 2,486	441	$ 5.64

Table of Contents

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

	Earnings (Loss)	Common Shares	Earnings (Loss) per Share
	(In millions, except per share amounts)		
Nine Months Ended September 30, 2009:			
Loss from continuing operations	$ (3,162)	444	
Attributable to participating securities	34	(5)	
Basic and diluted loss per share	$ (3,128)	439	$ (7.12)
Nine Months Ended September 30, 2008:			
Earnings from continuing operations	$ 3,754	444	
Attributable to participating securities	(34)	(4)	
Less preferred stock dividends	(5)		
Basic earnings per share	3,715	440	$ 8.45
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		4	
Diluted earnings per share	$ 3,715	444	$ 8.37

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, 2009, 7.1 million shares and 8.9 million shares, respectively, were excluded from the diluted earnings per share calculations. During the three-month and nine-month periods ended September 30, 2008, 1.6 million shares and 1.5 million shares, respectively, were excluded from the diluted earnings per share calculations.

19. Segment Information

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

	Domestic	Canada	International	Total
	(In millions)			
As of September 30, 2009:				
Current assets	$ 1,332	$ 678	$ 599	$ 2,609
Property and equipment, net	12,626	5,261	985	18,872
Goodwill	3,046	2,815	68	5,929
Other long-term assets	455	52	224	731
Total assets	$ 17,459	$ 8,806	$ 1,876	$ 28,141
Current liabilities	$ 2,822	$ 420	$ 201	$ 3,443
Long-term debt	2,868	2,980		5,848

Asset retirement obligation, long-term	763	646	102	1,511
Other long-term liabilities	930	45	2	977
Deferred income taxes	591	1,036	82	1,709
Stockholders equity	9,485	3,679	1,489	14,653
Total liabilities and stockholders equity	$ 17,459	$ 8,806	$ 1,876	$ 28,141

22

Table of Contents

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

	Domestic	Canada	International	Total
	(In millions)			
Three Months Ended September 30, 2009:				
Revenues:				
Oil sales	$ 279	$ 318	$ 248	$ 845
Gas sales	518	171	2	691
NGL sales	164	31		195
Net gain on oil and gas derivative financial instruments	23			23
Marketing and midstream revenues	333	11		344
Total revenues	1,317	531	250	2,098
Expenses and other income, net:				
Lease operating expenses	276	181	48	505
Production taxes	35		26	61
Marketing and midstream operating costs and expenses	239	5		244
Depreciation, depletion and amortization of oil and gas properties	270	154	56	480
Depreciation and amortization of non-oil and gas properties	58	6	1	65
Accretion of asset retirement obligation	12	10	3	25
General and administrative expenses	108	28	1	137
Interest expense	34	56		90
Change in fair value of other financial instruments	(5)			(5)
Other (income) expense, net	(98)	7	(5)	(96)
Total expenses and other income, net	929	447	130	1,506
Earnings from continuing operations before income taxes	388	84	120	592
Income tax expense (benefit):				
Current	27	58	17	102
Deferred	30	(26)	(13)	(9)
Total income tax expense	57	32	4	93
Net earnings applicable to common stockholders	$ 331	$ 52	$ 116	$ 499
Capital expenditures, continuing operations	$ 698	$ 247	$ 91	$ 1,036

Table of Contents

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

	Domestic	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2008:				
Revenues:				
Oil sales	$ 467	$ 507	$ 322	$ 1,296
Gas sales	1,598	504	5	2,107
NGL sales	288	74		362
Net gain on oil and gas derivative financial instruments	1,592			1,592
Marketing and midstream revenues	607	14		621
Total revenues	4,552	1,099	327	5,978
Expenses and other income, net:				
Lease operating expenses	318	217	56	591
Production taxes	87	1	64	152
Marketing and midstream operating costs and expenses	447	5		452
Depreciation, depletion and amortization of oil and gas properties	505	224	52	781
Depreciation and amortization of non-oil and gas properties	60	7		67
Accretion of asset retirement obligation	11	10	1	22
General and administrative expenses	114	31	1	146
Interest expense	15	54		69
Change in fair value of other financial instruments	46			46
Other income, net	(75)	(7)	(1)	(83)
Total expenses and other income, net	1,528	542	173	2,243
Earnings from continuing operations before income taxes	3,024	557	154	3,735
Income tax expense (benefit):				
Current	83	85	58	226
Deferred	946	74	(20)	1,000
Total income tax expense	1,029	159	38	1,226
Earnings from continuing operations	1,995	398	116	2,509
Discontinued operations:				
Earnings from discontinued operations before income taxes			93	93
Income tax benefit			(16)	(16)
Earnings from discontinued operations			109	109
Net earnings applicable to common stockholders	$ 1,995	$ 398	$ 225	$ 2,618

Capital expenditures, before revision of future ARO	$ 1,717	$ 508	$ 133	$ 2,358
Revision of future ARO	82			82
Capital expenditures, continuing operations	$ 1,799	$ 508	$ 133	$ 2,440

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

	Domestic	Canada	International	Total
	(In millions)			
Nine Months Ended September 30, 2009:				
Revenues:				
Oil sales	$ 654	$ 811	$ 642	$ 2,107
Gas sales	1,738	602	4	2,344
NGL sales	414	87		501
Net gain on oil and gas derivative financial instruments	190			190
Marketing and midstream revenues	1,048	26		1,074
Total revenues	4,044	1,526	646	6,216
Expenses and other income, net:				
Lease operating expenses	878	525	136	1,539
Production taxes	94	1	55	150
Marketing and midstream operating costs and expenses	694	13		707
Depreciation, depletion and amortization of oil and gas properties	984	430	159	1,573
Depreciation and amortization of non-oil and gas properties	189	19	1	209
Accretion of asset retirement obligation	40	28	5	73
General and administrative expenses	398	88	(1)	485
Interest expense	95	168		263
Change in fair value of other financial instruments	(20)			(20)
Reduction of carrying value of oil and gas properties	6,408		108	6,516
Other (income) expense, net	(84)	23	(8)	(69)
Total expenses and other income, net	9,676	1,295	455	11,426
Earnings (loss) from continuing operations before income taxes	(5,632)	231	191	(5,210)
Income tax expense (benefit):				
Current	28	104	23	155
Deferred	(2,194)	(23)	14	(2,203)
Total income tax (benefit) expense	(2,166)	81	37	(2,048)
Earnings (loss) from continuing operations	(3,466)	150	154	(3,162)
Earnings from discontinued operations			16	16
Net earnings (loss) applicable to common stockholders	$ (3,466)	$ 150	$ 170	$ (3,146)

Capital expenditures, before revision of future ARO	$	2,606	$	733	$	294	$	3,633
Revision of future ARO		37		(15)		1		23
Capital expenditures, continuing operations	$	2,643	$	718	$	295	$	3,656

Table of Contents

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

	Domestic	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2008:				
Revenues:				
Oil sales	$ 1,476	$ 1,345	$ 1,180	$ 4,001
Gas sales	4,522	1,410	15	5,947
NGL sales	859	210		1,069
Net loss on oil and gas derivative financial instruments	(411)			(411)
Marketing and midstream revenues	1,856	39		1,895
Total revenues	8,302	3,004	1,195	12,501
Expenses and other income, net:				
Lease operating expenses	863	622	149	1,634
Production taxes	270	3	189	462
Marketing and midstream operating costs and expenses	1,334	15		1,349
Depreciation, depletion and amortization of oil and gas properties	1,446	662	172	2,280
Depreciation and amortization of non-oil and gas properties	165	20	1	186
Accretion of asset retirement obligation	32	30	4	66
General and administrative expenses	373	99	2	474
Interest expense	103	158		261
Change in fair value of other financial instruments	22			22
Other income, net	(92)	(12)	(17)	(121)
Total expenses and other income, net	4,516	1,597	500	6,613
Earnings from continuing operations before income taxes	3,786	1,407	695	5,888
Income tax expense:				
Current	428	149	166	743
Deferred	1,159	226	6	1,391
Total income tax expense	1,587	375	172	2,134
Earnings from continuing operations	2,199	1,032	523	3,754
Discontinued operations:				
Earnings from discontinued operations before income taxes			1,133	1,133
Income tax expense			219	219
Earnings from discontinued operations			914	914

Net earnings	2,199	1,032	1,437	4,668
Preferred stock dividends	5			5
Net earnings applicable to common stockholders	$ 2,194	$ 1,032	$ 1,437	$ 4,663
Capital expenditures, before revision of future ARO	$ 4,682	$ 1,206	$ 437	$ 6,325
Revision of future ARO	152	73	19	244
Capital expenditures, continuing operations	$ 4,834	$ 1,279	$ 456	$ 6,569

Table of Contents

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

20. Supplemental Information to Statements of Cash Flows

Additional information related to Devon s cash flows for the nine-month periods ended September 30, 2009 and 2008 are presented below.

	Nine Months Ended September 30, 2009	2008
	(In millions)	
Net (increase) decrease in working capital:		
Decrease (increase) in accounts receivable	$ 305	$ 32
Decrease (increase) in other current assets	144	(67)
(Decrease) increase in accounts payable	(56)	190
(Decrease) increase in revenues and royalties due to others	(124)	278
Decrease in other current liabilities	(270)	(94)
Net (increase) decrease in working capital	$ (1)	$ 339
Supplementary cash flow data continuing and discontinued operations:		
Interest paid net of capitalized interest	$ 273	$ 298
Income taxes (received) paid	$ (29)	$ 1,162

27

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, 2009, compared to the three-month and nine-month periods ended September 30, 2008, and in our financial condition and liquidity since December 31, 2008. For information regarding our critical accounting policies and estimates, see our 2008 Annual Report on Form 10-K under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

Business Overview

The downward pressure in natural gas prices that began in the last half of 2008 has continued into the first nine months of 2009. The Henry Hub natural gas index for the third quarter of 2009 was down 51% from the fourth quarter of 2008 and 67% from the third quarter of 2008. Additionally, although oil index prices have improved since the end of 2008, the West Texas Intermediate oil index dropped 42% from the third quarter of 2008 to the third quarter of 2009.

The lower oil and gas prices have significantly impacted our earnings for the third quarter and first nine months of 2009. During the third quarter of 2009 and first nine months of 2009, we generated net earnings of $499 million, or $1.12 per diluted share, and a net loss of $3.1 billion, or $7.09 per diluted share, for the respective periods. These amounts are significantly lower than the comparative earnings amounts for 2008. The loss in the first nine months of 2009 was the result of noncash impairments of our oil and gas properties in the first quarter that totaled $4.2 billion, net of income taxes. Substantially all of this noncash charge was the result of the drop in natural gas prices since December 31, 2008.

Key measures of our performance for the third quarter and first nine months of 2009 compared to 2008 are summarized below:

- Production increased 6% and 8% in the third quarter and first nine months of 2009, respectively.
- The combined realized price without hedges for oil, gas and NGLs decreased 56% and 58% in the third quarter and first nine months of 2009, respectively.
- Marketing and midstream operating profit decreased 41% to $100 million and 33% to $367 in the third quarter and first nine months of 2009, respectively.
- Per unit operating costs decreased 28% to $9.15 per Boe and 25% to $8.94 per Boe in the third quarter and first nine months of 2009, respectively.
- Oil and gas hedges generated net gains of $23 million and $190 million in the third quarter and first nine months of 2009, respectively. Our hedges generated a net gain of $1.6 billion in third quarter of 2008 and a net loss of $411 million in the first nine months of 2008. Included in these amounts were cash receipts of $127 million and $359 million for the third quarter and first nine months of 2009, respectively, and payments of $240 million and $551 million in the third quarter and first nine months of 2008, respectively.
- Operating cash flow decreased approximately 60% to $3.3 billion in the first nine months of 2009.
- Cash spent on capital expenditures was approximately $4.2 billion in the first nine months of 2009. Approximately 80% of this amount was funded with operating cash flow and the remainder was funded with commercial paper borrowings.

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 our $1.0 billion of outstanding commercial paper as of December 31, 2008.

During the second quarter of 2009, we announced the integration of our Gulf of Mexico and International operations into one offshore unit. This integration will provide greater focus and efficiency to these areas of our operations, which have similar scope, technical requirements and strategy.

We expect the challenging commodity price environment will likely persist in the coming months. As a result, we are continuing to execute the strategy we outlined at the beginning of the year. That strategy is to decrease our activity across our near-term development projects in North America and continue advancing our longer term development projects like our

Table of Contents

second Jackfish heavy oil project in Canada and our Lower Tertiary developments in the Gulf of Mexico. We also continue to drive costs lower and maintain our strong liquidity position until we see signs of recovery in the hydrocarbon markets.

As part of this strategy, in the second quarter of 2009, we announced plans to pursue a partner to participate in our Lower Tertiary projects in the Gulf of Mexico. The proceeds from such a transaction would supplement the liquidity provided by our operating cash flow and credit lines. Additionally, such a transaction would give us greater flexibility to adjust capital expenditures to changes in cash flow, particularly in these times of lower commodity prices.

Although oil and gas prices remain depressed compared to recent highs achieved in 2008, and our operating cash flow has been negatively impacted, we expect to have adequate liquidity to execute our near-term operating strategy and maintain momentum on our longer-term projects. As of November 2, 2009, we had unused lines of credit totaling $2.0 billion and continue to have access to the commercial paper market. We anticipate these capital sources combined with our operating cash flow will be sufficient to fund our planned capital expenditures and other capital uses over the near-term. Furthermore, our available cash resources position us with adequate capital to quickly increase exploration and development activities once commodity prices show signs of long-term improvement.

Results of Operations

Revenues

The three-month and nine-month comparison of our oil, gas and NGL production, prices and revenues for the third quarter and first nine months of 2009 and 2008 are shown in the following tables. The amounts for all periods presented exclude our West African operations that are classified as discontinued operations in our financial statements.

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change(2)	2009	2008	Change(2)
Production						
Oil (MMBbls)	14	12	+14%	43	39	+8%
Gas (Bcf)	243	239	+2%	742	692	+7%
NGLs (MMBbls)	8	7	+14%	23	21	+10%
Total (MMBoe)(1)	62	58	+6%	189	175	+8%
Realized prices without hedges						
Oil (Per Bbl)	$ 61.12	$ 106.95	-43%	$ 49.30	$ 101.42	-51%
Gas (Per Mcf)	$ 2.84	$ 8.82	-68%	$ 3.16	$ 8.60	-63%
NGLs (Per Bbl)	$ 25.67	$ 54.72	-53%	$ 22.21	$ 52.03	-57%
Combined (Per Boe)(1)	$ 27.97	$ 64.29	-56%	$ 26.21	$ 62.84	-58%
Revenues ($ in millions)						
Oil sales	$ 845	$ 1,296	-35%	$ 2,107	$ 4,001	-47%
Gas sales	691	2,107	-67%	2,344	5,947	-61%
NGL sales	195	362	-46%	501	1,069	-53%
Total	$ 1,731	$ 3,765	-54%	$ 4,952	$ 11,017	-55%

Table of Contents

Domestic

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Change(2)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change(2)
Production						
Oil (MMBbls)	4	4	+9%	12	13	-6%
Gas (Bcf)	184	185	-0%	570	532	+7%
NGLs (MMBbls)	7	6	+19%	20	18	+12%
Total (MMBoe)(1)	42	40	+3%	127	119	+6%
Realized prices without hedges						
Oil (Per Bbl)	$ 65.01	$ 118.70	-45%	$ 52.60	$ 111.94	-53%
Gas (Per Mcf)	$ 2.82	$ 8.66	-67%	$ 3.05	$ 8.50	-64%
NGLs (Per Bbl)	$ 24.56	$ 51.50	-52%	$ 21.04	$ 48.96	-57%
Combined (Per Boe)(1)	$ 23.09	$ 58.38	-60%	$ 22.09	$ 57.43	-62%
Revenues ($ in millions)						
Oil sales	$ 279	$ 467	-40%	$ 654	$ 1,476	-56%
Gas sales	518	1,598	-68%	1,738	4,522	-62%
NGL sales	164	288	-43%	414	859	-52%
Total	$ 961	$ 2,353	-59%	$ 2,806	$ 6,857	-59%

Canada

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Change(2)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change(2)
Production						
Oil (MMBbls)	6	5	+6%	19	15	+21%
Gas (Bcf)	58	54	+9%	171	159	+8%
NGLs (MMBbls)	1	1	-12%	3	3	-4%
Total (MMBoe)(1)	16	15	+6%	50	45	+12%
Realized prices without hedges						
Oil (Per Bbl)	$ 55.10	$ 92.98	-41%	$ 43.42	$ 87.28	-50%
Gas (Per Mcf)	$ 2.91	$ 9.36	-69%	$ 3.51	$ 8.90	-61%
NGLs (Per Bbl)	$ 33.81	$ 72.19	-53%	$ 30.20	$ 70.00	-57%
Combined (Per Boe)(1)	$ 31.62	$ 70.24	-55%	$ 29.94	$ 66.16	-55%
Revenues ($ in millions)						
Oil sales	$ 318	$ 507	-37%	$ 811	$ 1,345	-40%
Gas sales	171	504	-66%	602	1,410	-57%
NGL sales	31	74	-59%	87	210	-59%
Total	$ 520	$ 1,085	-52%	$ 1,500	$ 2,965	-49%

30

Table of Contents

	International					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Change(2)	2009	2008	Change(2)
Production						
Oil (MMBbls)	4	3	+38%	12	11	+7%
Gas (Bcf)	1		N/M	1	1	N/M
NGLs (MMBbls)			N/M			N/M
Total (MMBoe)(1)	4	3	+36%	12	11	+6%
Realized prices without hedges						
Oil (Per Bbl)	$ 65.94	$ 117.97	-44%	$ 55.23	$ 108.73	-49%
Gas (Per Mcf)	$ 5.90	$ 10.72	-45%	$ 4.65	$ 9.95	-53%
NGLs (Per Bbl)	$	$	N/M	$	$	N/M
Combined (Per Boe)(1)	$ 65.42	$ 116.35	-44%	$ 54.85	$ 107.63	-49%
Revenues ($ in millions)						
Oil sales	$ 248	$ 322	-23%	$ 642	$ 1,180	-46%
Gas sales	2	5	-58%	4	15	-69%
NGL sales			N/M			N/M
Total	$ 250	$ 327	-23%	$ 646	$ 1,195	-46%

(1) Gas volumes are converted to Boe or MMBoe 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 oil and gas 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 are not calculated using the rounded figures included in this table.

N/M Not meaningful.

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, 2009 and 2008.

	Oil	Gas	NGLs	Total
		(In millions)		
2008 sales	$ 1,296	$ 2,107	$ 362	$ 3,765
Changes due to volumes	184	34	52	270
Changes due to prices	(635)	(1,450)	(219)	(2,304)
2009 sales	$ 845	$ 691	$ 195	$ 1,731

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, 2009 and 2008.

	Oil	Gas	NGLs	Total
		(In millions)		
2008 sales	$ 4,001	$ 5,947	$ 1,069	$ 11,017
Changes due to volumes	334	428	104	866
Changes due to prices	(2,228)	(4,031)	(672)	(6,931)
2009 sales	$ 2,107	$ 2,344	$ 501	$ 4,952

Oil Sales

Oil sales decreased $635 million in the third quarter of 2009 as a result of a 43% decrease in our realized price without hedges. The average NYMEX West Texas Intermediate index price decreased 42% during the same time period, accounting for the majority of the decrease.

Oil sales increased $184 million in the third quarter of 2009 due to a two million barrel increase in production. The increased production resulted primarily from the continued development activities at our Jackfish operations in Canada and at our Polvo operations in Brazil.

Oil sales decreased $2.2 billion in the first nine months of 2009 as a result of a 51% decrease in our realized price without hedges. The average NYMEX West Texas Intermediate index price decreased 50% during the same time period, accounting for the majority of the decrease.

Oil sales increased $334 million in the first nine months of 2009 due to a four million barrel increase in production. The increased production resulted primarily from the continued development at our Jackfish operations in Canada and at our Polvo operations in Brazil. These increases were partially offset by decreased production in Azerbaijan as a result of reaching certain cost recovery thresholds.

Gas Sales

Gas sales decreased $1.5 billion during the third quarter of 2009 as a result of a 68% decrease in our realized price without hedges. This decrease was largely due to decreases in the North American regional index prices upon which our gas sales are based.

A four Bcf increase in production during the third quarter of 2009 caused gas sales to increase by $34 million. Gas production increased 10 Bcf due to a decline in Canadian government royalties largely resulting from lower gas prices. Also, we restored five Bcf of production that was deferred in the third quarter of 2008 due to hurricanes. These increases were largely offset by lower production from our North American onshore properties due to the net effect of natural production declines in excess of new production from drilling and development. In response to continued declining natural gas prices throughout 2009, we have scaled back our North American onshore natural gas drilling programs. As a result, we began experiencing production declines in the third quarter that outpaced new production from development activities performed in late 2008 and early 2009.

Gas sales decreased $4.0 billion during the first nine months of 2009 as a result of a 63% decrease in our realized price without hedges. This decrease is largely due to decreases in the regional index prices upon which our gas sales are based.

A 50 Bcf increase in production during the first nine months of 2009 caused gas sales to increase by $428 million. Our North American onshore properties contributed 40 Bcf to our growth as a result of new production from drilling and development that exceeded natural production declines. This increase was led by higher production from the Barnett Shale, which contributed 22 Bcf. Gas production also increased 22 Bcf due to a decline in Canadian government royalties largely resulting from lower gas prices. These increases were partially offset by 12 Bcf of lower production from our United States Offshore properties, largely resulting from natural production declines.

NGL Sales

NGL sales decreased $219 million during the third quarter of 2009 as a result of a 53% decrease in our realized price without hedges. This decrease was largely due to decreases in the regional index prices upon which our NGL sales are based. NGL sales increased $52 million in the third quarter of 2009 due to a one million barrel increase in production that was primarily related to our Barnett Shale and Woodford Shale activity.

NGL sales decreased $672 million during the first nine months of 2009 as a result of a 57% decrease in our realized price without hedges. This decrease is largely due to decreases in the regional index prices upon which our NGL sales are based. NGL sales increased $104 million in the first nine months of 2009 due to a two million barrel increase in production. The higher production resulted primarily from development in the Barnett Shale and Woodford Shale.

Net Gain (Loss) on Oil and Gas Derivative Financial Instruments

The following tables provide financial information associated with our oil and gas hedges for the third quarter and first nine months of 2009 and 2008. 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 for the three and nine months ended September 30, 2009 and 2008. The prices do not include the effects of unrealized gains and losses.

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
		(In millions)		
Cash settlement receipts (payments):				
Gas price collars	$ 118	$ (125)	$ 350	$ (275)
Gas price swaps	9	(115)	9	(276)
Total cash settlements	127	(240)	359	(551)
Unrealized gains (losses):				
Gas price collars	(104)	1,142	(169)	114
Gas price swaps	(7)	645	(7)	27
Oil price collars	7	45	7	(1)
Total unrealized gains (losses)	(104)	1,832	(169)	140
Net gain (loss) on oil and gas derivative financial instruments	$ 23	$ 1,592	$ 190	$ (411)

	Three Months Ended September 30, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 61.12	$ 2.84	$ 25.67	$ 27.97
Cash settlements of hedges		0.53		2.05
Realized price, including cash settlements	$ 61.12	$ 3.37	$ 25.67	$ 30.02

	Three Months Ended September 30, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 106.95	$ 8.82	$ 54.72	$ 64.29
Cash settlements of hedges	(0.01)	(1.01)		(4.10)
Realized price, including cash settlements	$ 106.94	$ 7.81	$ 54.72	$ 60.19

	Nine Months Ended September 30, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 49.30	$ 3.16	$ 22.21	$ 26.21
Cash settlements of hedges		0.48		1.90

Realized price, including cash settlements	$ 49.30	$ 3.64	$ 22.21	$ 28.11

	Nine Months Ended September 30, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 101.42	$ 8.60	$ 52.03	$ 62.84
Cash settlements of hedges		(0.80)		(3.15)
Realized price, including cash settlements	$ 101.42	$ 7.80	$ 52.03	$ 59.69

Our oil and gas derivative financial instruments include price swaps and costless 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 to the collars. Cash settlements as presented in the tables above represent realized gains or losses related to our price swaps and collars.

During the third quarter and first nine months of 2009, we received $127 million, or $0.53 per Mcf, and $359 million, or $0.48 per Mcf, respectively from counterparties to settle our gas price contracts. During the third quarter and first nine months of 2008, we paid $240 million, or $1.01 per Mcf, and $551 million, or $0.80 per Mcf, respectively, to counterparties to settle our gas price collars and swaps.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil and gas derivative instruments in each reporting period. We estimate the fair values of our oil and gas derivative financial instruments 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 price swaps and collars at September 30, 2009, a 10% increase in these forward curves would have increased our 2009 unrealized losses for our gas derivative financial instruments by approximately $134 million. A 10% increase in the forward curves associated with our oil derivative financial instruments would have decreased our 2009 unrealized gains by approximately $32 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.

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 twelve 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, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of September 30, 2009, the credit ratings of all our counterparties were investment grade.

During the third quarter and first nine months of 2009, we reduced the fair value of our derivative financial instruments by $104 million and $169 million, respectively. These reductions largely represent the realization of previously recorded unrealized gains on our gas price collar contracts, which is expected as the contracts near their December 31, 2009 expiration date.

During the third quarter and first nine months of 2008, we increased the fair value of our derivative financial instruments by $1.8 billion and $140 million, respectively. The $1.8 billion unrealized gain in the third quarter of 2008 was primarily the result of large fluctuations in the forward curves of the Inside FERC Henry Hub index. As a result of a significant increase in the Inside FERC Henry Hub forward curve from our contract trade dates to the end of the second quarter of 2008, we recognized a $1.7 billion unrealized loss during the first half of 2008. During the third quarter of 2008, the Inside FERC Henry Hub forward curve decreased considerably. As a result we recognized an unrealized gain of $1.8 billion, in effect, reversing the unrealized loss recognized in the first half of 2008.

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 between the three and nine months ended September 30, 2009 and 2008 are shown in the table below.

	Three Months Ended September 30,			**Nine Months Ended September 30,**		
	2009	**2008**	**Change(1)**	**2009**	**2008**	**Change(1)**
	($ in millions)					
Marketing and midstream:						
Revenues	$ 344	$ 621	-45%	$ 1,074	$ 1,895	-43%
Operating costs and expenses	244	452	-46%	707	1,349	-48%
Operating profit	$ 100	$ 169	-41%	$ 367	$ 546	-33%

(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 2009, marketing and midstream revenues decreased $277 million and operating costs and expenses decreased $208 million, causing operating profit to decrease $69 million. Revenues and expenses decreased in the third quarter of 2009 primarily due to lower natural gas and NGL prices, partially offset by higher NGL production.

During the first nine months of 2009, marketing and midstream revenues decreased $821 million and operating costs and expenses also decreased $642 million, causing operating profit to decrease $179 million. Revenues and expenses decreased in the first nine months of 2009 primarily due to lower natural gas and NGL prices, partially offset by the effects of increased gas pipeline throughput and higher NGL production.

Oil, Gas and NGL Production and Operating Expenses

The details of the changes in oil, gas and NGL production and operating expenses between the three and nine months ended September 30, 2009 and 2008 are shown in the table below.

	Three Months Ended September 30,			**Nine Months Ended September 30,**		
	2009	**2008**	**Change[(1)]**	**2009**	**2008**	**Change[(1)]**
			($ in millions)			
Production and operating expenses:						
Lease operating expenses	$ 505	$ 591	-15%	$ 1,539	$ 1,634	-6%
Production taxes	61	152	-60%	150	462	-68%
Total production and operating expenses	$ 566	$ 743	-24%	$ 1,689	$ 2,096	-19%
Production and operating expenses per Boe:						
Lease operating expenses	$ 8.16	$ 10.09	-19%	$ 8.15	$ 9.32	-13%
Production taxes	0.99	2.60	-62%	0.79	2.64	-70%
Total production and operating expenses per Boe	$ 9.15	$ 12.69	-28%	$ 8.94	$ 11.96	-25%

(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.

Lease Operating Expenses (LOE)

LOE decreased $86 million in the third quarter of 2009. LOE decreased $95 million due to declining costs for fuel, materials, equipment and personnel, as well as a decline in recurring activities and well workover projects. Such declines largely resulted from decreasing demand for field services due to lower oil and gas prices compared to recent periods. LOE also decreased $14 million due to damages to certain of our facilities and transportation systems that were caused by Hurricane Ike in the third quarter of 2008. In addition, LOE decreased $10 million due to the effects of changes in the exchange rate between the U.S. and Canadian dollar. These factors were also the main contributors to the decrease in our LOE per Boe. Partially offsetting these decreases was a $33 million increase in LOE associated with our 6% production growth.

LOE decreased $95 million in the first nine months of 2009. LOE decreased $129 million due to declining costs for fuel, materials, equipment and personnel, as well as a decline in recurring activities and well workover projects. LOE also decreased $78 million due to the effects of changes in the exchange rate between the U.S. and Canadian dollar. Additionally, LOE decreased $14 million as a result of damages to certain of our facilities and transportation systems that were caused by Hurricane Ike in the third quarter of 2008. These factors were also the main contributors to the decrease in our LOE per Boe. Partially offsetting these decreases was a $126 million increase in LOE associated with our 8% production growth.

Production Taxes

The following table details the changes in production taxes between the three and nine months ended September 30, 2009 and 2008.

	Three Months Ended September 30,	Nine Months Ended September 30,
	(In millions)	
2008 production taxes	$ 152	$ 462
Change due to revenues	(82)	(254)
Change due to rate	(9)	(58)
2009 production taxes	$ 61	$ 150

The majority of our production taxes are assessed on our U.S. onshore properties and are generally based on a fixed percentage of revenues. Production taxes are also assessed on certain of our International properties based on a variable percentage of revenues that generally moves in tandem with commodity prices. Therefore, the changes due to revenues in the table above primarily relate to changes in oil, gas and NGL revenues from our U.S. onshore and International properties. The changes due to rate largely result from lower variable tax rates on our International properties, as well as tax credits received on certain of our United States onshore properties.

Depreciation, Depletion and Amortization Expenses (DD&A)

The changes in our production volumes, DD&A rate per unit and DD&A of oil and gas properties between the three and nine months ended September 30, 2009 and 2008 are shown in the table below.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	**2008**	**Change(1)**	**2009**	**2008**	**Change(1)**
Production volumes (MMBoe)	62	58	+6%	189	175	+8%
DD&A rate ($ per Boe)	$ 7.75	$ 13.34	-42%	$ 8.33	$ 13.01	-36%
DD&A expense ($ in millions)	$ 480	$ 781	-39%	$ 1,573	$ 2,280	-31%

(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, 2009 and 2008.

	Three Months Ended September 30,	Nine Months Ended September 30,
	(In millions)	
2008 DD&A	$ 781	$ 2,280
Change due to volumes	45	177
Change due to rate	(346)	(884)
2009 DD&A	$ 480	$ 1,573

The 6% production increase during the third quarter of 2009 caused oil and gas property related DD&A to increase $45 million. The 8% production increase during the first nine months of 2009 caused oil and gas property related DD&A to increase $177 million.

Oil and gas property-related DD&A decreased $346 million during the third quarter of 2009 due to a 42% decrease in the DD&A rate. Oil and gas property-related DD&A decreased $884 million during the first nine months of 2009 due to a 36% decrease in the DD&A rate. The largest contributors to the rate decreases were reductions of the carrying values of certain of our oil and gas properties recognized in the first quarter of 2009 and the fourth quarter of 2008. These reductions totaled $16.9 billion and resulted from full cost ceiling limitations. In addition, the effects of changes in the exchange rate between the U.S. and Canadian dollar also contributed to the rate decreases. These decreases were partially offset by the effects of costs incurred and transfers of previously unproved costs to the depletable base as a result of drilling activities subsequent to the third quarter of 2008.

General and Administrative Expenses (G&A)

The details of the changes in G&A expense between the three and nine months ended September 30, 2009 and 2008 are shown in the table below.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Change(1)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change(1)
	($ in millions)					
Gross G&A	$ 264	$ 280	-6%	$ 885	$ 864	+2%
Capitalized G&A	(94)	(99)	-5%	(302)	(298)	+1%
Reimbursed G&A	(33)	(35)	-5%	(98)	(92)	+6%
Net G&A	$ 137	$ 146	-7%	$ 485	$ 474	+2%

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

Gross G&A decreased $16 million in the third quarter of 2009 compared to the same period of 2008. Gross G&A decreased largely as a result of initiatives we have instituted during 2009 to manage spending in certain discretionary cost categories. The effects of these initiatives were partially offset by approximately $10 million of higher costs for employee compensation and benefits. The higher employee costs resulted primarily from an increase in postretirement benefits costs and higher severance costs associated with employee departures.

Gross G&A increased $21 million in the first nine months of 2009 compared to the same period of 2008. This increase was due to approximately $64 million of higher costs for employee compensation and benefits, partially offset by the effects of our 2009 reduced spending initiatives for certain discretionary cost categories. Employee cost increases in 2009 included an additional $55 million of severance costs. This increase was due to the integration of our Gulf of Mexico and International operations into one offshore unit in the second quarter of 2009 and other employee departures during 2009. Additionally, employee costs increased approximately $42 million due to an increase in postretirement benefits costs.

These increases in employee costs were partially offset by a $27 million decrease due to accelerated share-based compensation expense recognized in the second quarter of 2008. In the second quarter of 2008, we modified the share-based compensation arrangements for certain members of senior management. The modified compensation arrangements provide that executives who meet certain years-of-service and age criteria can retire and continue vesting in outstanding share-based grants. As a condition to receiving the benefits of these modifications, the executives must agree not to use or disclose Devon s confidential information and not to solicit Devon s employees and customers. The executives are required to agree to these conditions at retirement and again in each subsequent year until all grants have vested. This modification results in accelerated expense recognition as executives approach the years-of-service and age criteria.

Interest Expense

The following schedule includes the components of interest expense for the three-month and nine-month periods ended September 30, 2009 and 2008.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Interest based on debt outstanding	$ 112	$ 96	$ 330	$ 332
Capitalized interest	(22)	(28)	(71)	(84)
Other		1	4	13
Total	$ 90	$ 69	$ 263	$ 261

Interest based on debt outstanding increased during the third quarter of 2009 primarily due to additional interest related to the $500 million of 5.625% senior unsecured notes and $700 million of 6.30% senior unsecured notes that we issued in January 2009. This was partially offset by lower interest resulting from the retirement of our exchangeable debentures during the third quarter of 2008.

Interest based on debt outstanding decreased during the first nine months of 2009 due to lower interest rates on our commercial paper borrowings and the retirement of our exchangeable debentures during the third quarter of 2008. This was partially offset by the additional interest resulting from the issuance of debt in January 2009 as discussed above.

Change in Fair Value of Other Financial Instruments

The details of the changes in fair value of other financial instruments for the three-month and nine-month periods ended September 30, 2009 and 2008 are shown in the table below.

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

	2009	2008	2009	2008
		(In millions)		
(Gains) losses from:				
Interest rate swaps settlements	$ (14)	$	$ (35)	$
Interest rate swaps fair value changes	9	(23)	15	(23)
Chevron common stock		236		154
Option embedded in exchangeable debentures		(167)		(109)
Total	$ (5)	$ 46	$ (20)	$ 22

Interest Rate Swaps

During the third quarter and first nine months of 2009, we received cash settlements totaling $14 million and $35 million, respectively, from counterparties to settle our interest rate swaps. We also recognize unrealized changes in the fair values of our interest rate swaps each reporting period. In the third quarter and first nine months of 2009, we recorded a $9 million and $15 million unrealized loss, respectively, as a result of changes in interest rates. In the third quarter of 2008, we recorded a $23 million unrealized gain as a result of changes in interest rates. There were no cash settlements in the third quarter of 2008.

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, 2009, a 10% increase in these forward curves would have decreased our 2009 unrealized losses for our interest rate swaps by approximately $30 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 six 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, 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, 2009.

Chevron Common Stock and Related Embedded Option

The third quarter and first nine months of 2008 losses on our investment in Chevron common stock were directly attributable to a $16.65 and $10.85 decrease in the price per share of Chevron s common stock during the third quarter and first nine months of 2008, respectively. The gains on the embedded option during the third quarter and first nine months of 2008 were directly attributable to the change in fair value of the Chevron common stock from July 1, 2008 to the associated debentures maturity date of August 15, 2008.

Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, we reduced the carrying values of certain of our oil and gas properties due to full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

	March 31, 2009	
	Gross	Net of Taxes
	(In millions)	
United States	$ 6,408	$ 4,085
Brazil	103	103
Russia	5	2
Total	$ 6,516	$ 4,190

The United States reduction resulted primarily from a significant decrease in the full cost ceiling during the first three months of 2009. The lower ceiling value in the United States largely resulted from the continued effects of declining natural gas prices subsequent to December 31, 2008.

Although oil prices improved subsequent to December 31, 2008, Brazil s 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.

To demonstrate the changes in the full-cost ceiling for the United States and Brazil, the March 31, 2009 and December 31, 2008 weighted average wellhead prices are presented in the following table.

	March 31, 2009			December 31, 2008		
Country	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)
United States	$47.30	$2.67	$17.04	$42.21	$4.68	$16.16
Brazil	$36.71	N/A	N/A	$26.61	N/A	N/A

N/A Not applicable.

The March 31, 2009 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $49.66 per Bbl for crude oil and the Henry Hub spot price of $3.63 per MMBtu for gas. The December 31, 2008 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for gas.

Other Income

The following schedule includes the components of other income for the three-month and nine-month periods ended September 30, 2009 and 2008.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In millions)			
Interest and dividend income	$ 3	$ 18	$ 7	$ 65
Deep water royalties	84		84	
Hurricane insurance proceeds		57		57
Other	9	8	(22)	(1)
Total	$ 96	$ 83	$ 69	$ 121

Interest and dividend income decreased during the third quarter of 2009 and the first nine months of 2009 due to a decrease in dividends received on our previously owned investment in Chevron common stock and a decrease in interest received on cash equivalents due to lower rates and balances.

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.

We suffered insured damages in the third quarter of 2005 related to hurricanes that struck the Gulf of Mexico. During 2006 and 2007, we received $480 million as a full settlement of the amount due from our primary insurers and certain of our secondary insurers. Our claims under our then existing insurance arrangements included both physical damages and business interruption claims. As of September 30, 2008, we had used $418 million of these proceeds as reimbursement of past repair costs and deductible amounts and expected to utilize another $5 million on future repairs. As a result, we recognized $57 million of excess recoveries as other income in the third quarter of 2008.

Table of Contents

Income Taxes

The following table presents our total income tax expense (benefit) related to continuing operations and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate for the three-month and nine-month periods ended September 30, 2009 and 2008. The primary factors causing our effective rates to vary from 2008 to 2009, and differ from the U.S. statutory rate, are discussed below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Total income tax expense (benefit) (In millions)	$ 93	$ 1,226	$ (2,048)	$ 2,134
U.S. statutory income tax rate	35%	35%	(35%)	35%
Prior year tax return filings	(10%)		(1%)	
Unsuccessful international drilling	(4%)			
Repatriations and tax policy election changes				5%
Other, primarily taxation on foreign operations	(5%)	(2%)	(3%)	(4%)
Effective income tax rate	16%	33%	(39%)	36%

In the third quarter of 2009, we recognized $59 million of income tax benefits in conjunction with the filing of our 2008 and certain amended 2005, 2006 and 2007 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. Also in the third quarter of 2009, we recognized a $22 million current tax benefit related to certain unsuccessful international drilling results.

In the nine months ended September 30, 2009, our effective tax rate was impacted by the reductions of carrying value that totaled $6.5 billion and had associated deferred tax benefits of $2.3 billion. Excluding the effects of these reductions and the benefits discussed in the preceding paragraph, our effective tax rate for the third quarter and first nine months of 2009 was 29% and 27%, respectively.

For the nine months ended September 30, 2008, our effective income tax rate was higher than the U.S. statutory income tax rate largely due to two related factors. First, in the second quarter of 2008, we repatriated $1.3 billion in earnings from certain foreign subsidiaries to the United States. At the end of the second quarter of 2008, we also expected to repatriate approximately $1.5 billion in earnings from foreign subsidiaries to the United States during the last six months of 2008. Second, we made certain tax policy election changes in the second quarter of 2008 to minimize the taxes we otherwise would pay to all relevant tax jurisdictions for the cash repatriations, as well as the taxable gains associated with the sales of assets in West Africa. As a result of the repatriations and tax policy election changes, we recognized additional tax expense of $312 million during the second quarter of 2008. Of the $312 million, $295 million was recognized as current income tax expense, and $17 million was recognized as deferred tax expense. Excluding the $312 million of additional tax expense, our effective income tax rate would have been 31% for the first nine months of 2008.

After adjusting for the factors discussed in the preceding paragraphs, our 2009 and 2008 effective tax rates were lower than the U.S. statutory income tax rate largely due to our foreign operations, which have statutory rates lower than the U.S. statutory income tax rate.

Table of Contents

Earnings from Discontinued Operations

Following are the components of earnings from discontinued operations for the three and nine-months ended September 30, 2009 and 2008.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Earnings from discontinued operations before income taxes	$	$ 93	$ 16	$ 1,133
Income tax expense (benefit)		(16)		219
Earnings from discontinued operations	$	$ 109	$ 16	$ 914

Earnings from discontinued operations decreased $109 million in the third quarter of 2009 and decreased $898 million in the first nine months of 2009. Earnings in 2008 included $748 million of after-tax gains resulting from the sale of our assets in Equatorial Guinea, Gabon, Cote d Ivoire and other countries in the second and third quarters of 2008. Our discontinued earnings in 2008 also included operating earnings generated by the assets prior to their sale dates in the second and third quarters of 2008.

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,	
	2009	2008
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 3,287	$ 8,060
Commercial paper borrowings	1,368	
Proceeds from debt issuance, net of commercial paper repayments	182	
Sales of property and equipment	23	116
Stock option exercises	19	109
Net sales of long-term and short-term investments	6	247
Cash received from discontinued operations	6	1,898
Other	6	58
Total sources of cash and cash equivalents	**4,897**	**10,488**
Uses of cash and cash equivalents:		
Capital expenditures	(4,184)	(6,184)
Net commercial paper repayments		(1,004)
Repayments of debt	(1)	(2,481)
Repurchases of common stock		(665)
Redemption of preferred stock		(150)
Dividends	(213)	(216)

Total uses of cash and cash equivalents		**(4,398)**		**(10,700)**
Increase (decrease) from continuing operations		499		(212)
Increase from discontinued operations, net of distributions to continuing operations				82
Effect of foreign exchange rates		29		(47)
Net increase (decrease) in cash and cash equivalents	**$**	**528**	**$**	**(177)**
Cash and cash equivalents at end of period	**$**	**912**	**$**	**1,196**

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 2009. Changes in operating cash flow are largely due to the same factors that affect our

41

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 decreased in 2009 primarily due to the decrease in commodity prices and resulting revenues as discussed in the Results of Operations section of this report.

During the first nine months of 2009, our operating cash flow funded approximately 80% of our cash payments for capital expenditures. Commercial paper borrowings were used to fund the remainder of our cash-based capital expenditures. During the first nine months of 2008, our operating cash flow was sufficient to fund our cash payments for capital expenditures.

Other Sources of Cash

As needed, we utilize cash on hand and access our available credit under our credit facilities and commercial paper program as sources of cash to supplement our operating cash flow. We may also issue long-term debt to supplement our operating cash flow while maintaining adequate liquidity under our credit facilities. Additionally, we sometimes acquire short-term investments to maximize our income on available cash balances. As needed, we may reduce such short-term investment balances to further supplement our operating cash flow.

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 $1.005 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 expenditure and dividend payments in excess of our operating cash flow during the first nine months of 2009.

In 2008, another significant source of cash was the proceeds from our African divestiture program. During the first nine months of 2008, we received $2.6 billion in proceeds ($1.9 billion net of income taxes and purchase price adjustments) from sales of assets located in certain West African countries, including Equatorial Guinea the largest individual transaction in the divestiture program. Also, in conjunction with these asset sales, we repatriated an additional $2.3 billion of earnings from certain foreign subsidiaries to the United States in the first nine months of 2008.

During 2008, we used the proceeds from asset and investment sales, repatriated funds and our operating cash flow in excess of capital expenditures to fund debt repayments, common stock repurchases, preferred stock redemptions and dividends on common and preferred stock.

Capital Expenditures

Following are the components of our capital expenditures for the first nine months of 2009 and 2008. 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 2009 and 2008 were approximately $3.6 billion and $6.4 billion, respectively.

	Nine Months Ended September 30, 2009	**2008**
	(In millions)	
U.S. Onshore	$ 2,050	$ 3,381
U.S. Offshore	704	813
Canada	747	1,137
International	368	417
Total exploration and development	3,869	5,748
Midstream	230	310
Other	85	126

Total cash paid for capital expenditures	$ 4,184	$ 6,184

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling or development of oil and gas properties, which totaled $3.9 billion and $5.7 billion in the first nine months of 2009 and 2008, respectively. Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines.

Our exploration and development capital expenditures decreased $1.9 billion in the first nine months of 2009. The lower expenditures result from decreased drilling activities in most of our operating areas in response to lower commodity prices in 2009 compared to recent years.

Net Repayments of Debt in 2008

During the first nine months of 2008, we repaid $2.5 billion in outstanding credit facility and commercial paper borrowings primarily with proceeds received from the sales of assets under our African divestiture program and cash generated from operations. Also, during the first nine months of 2008, virtually all holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock owned by us. The debentures matured on August 15, 2008. In lieu of delivering our shares of Chevron common stock, we exercised our option to pay the exchanging debenture holders cash totaling $1.0 billion. This amount included the retirement of debentures with a book value of $652 million and a $379 reduction of the related embedded derivative option s balance.

Repurchases of Common Stock in 2008

During the first nine months of 2008, we repurchased 6.5 million common shares for $665 million, or $102.56 per share. The 6.5 million shares include 4.5 million shares that were repurchased under our 50 million share repurchase program and 2.0 million shares that were repurchased under our ongoing, annual stock repurchase program.

Redemption of Preferred Stock in 2008

On June 20, 2008, we redeemed all 1.5 million outstanding shares of our 6.49% Series A cumulative preferred stock. Each share of preferred stock was redeemed for cash at a redemption price of $100 per share, plus accrued and unpaid dividends up to the redemption date.

Dividends

Our common stock dividends were $213 million and $211 million (quarterly rates of $0.16 per share) in the first nine months of 2009 and 2008, respectively. Our preferred dividends were $5 million in the first nine months of 2008 prior to the June 20, 2008 redemption.

Liquidity

Our primary source of capital and liquidity has historically been our operating cash flow and cash on hand. Additionally, we maintain revolving lines of credit and a commercial paper program that can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. We estimate these capital resources will provide sufficient liquidity to fund our planned uses of capital.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs we produce. Due to sharp declines in commodity prices, our operating cash flow decreased approximately 60% to $3.3 billion in the first nine months of 2009 compared to the first nine months of 2008. In spite of the recent commodity price declines, we expect operating cash flow will continue to be a primary source of liquidity, and we will need to manage our capital expenditures and other cash uses accordingly.

However, as a result of depressed commodity prices, debt borrowings have been a significant source of liquidity during 2009. During the first nine months of 2009, our net borrowings of long-term debt and commercial paper totaled $1.6 billion. Additionally, based on near-term price expectations, we anticipate borrowing additional commercial paper during the remainder of 2009 to assist in funding our planned capital expenditures and other capital uses.

Credit Lines

As of November 2, 2009, we had $2.0 billion of available capacity under our syndicated, unsecured credit facilities that can be used to supplement our operating cash flow and cash on hand to fund our capital expenditures and other commitments.

Table of Contents

The following schedule summarizes the capacity of our credit facilities by maturity date, as well as our available capacity as of November 2, 2009.

Description	Amount (In millions)
Senior Credit Facility maturities:	
April 7, 2012	$ 500
April 7, 2013	2,150
Senior Credit Facility total capacity	2,650
Short-Term Facility total capacity November 2, 2010 maturity	700
Total credit facility capacity	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	1,253
Outstanding letters of credit	85
Total available capacity	$ 2,012

The credit facilities contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. As of September 30, 2009, we were in compliance with this covenant. Our debt-to-capitalization ratio at September 30, 2009, as calculated pursuant to the terms of the agreement, was 21.3%.

Other Capital Resources

We expect the challenging commodity price environment will likely persist in the coming months. As a result, we are continuing to execute the strategy we outlined at the beginning of the year. That strategy is to decrease our activity across our near-term development projects in North America, to continue advancing our longer term development projects like our second Jackfish heavy oil project in Canada and our Lower Tertiary developments in the Gulf of Mexico, and to continue to drive costs lower and to maintain our strong liquidity position until we see signs of recovery in the hydrocarbon markets.

Our successes in the deepwater Lower Tertiary and the Jackfish projects in Canada have resulted in growing long-term development commitments. While these long-term projects provide tremendous opportunity, the increasing share of our capital expenditures directed to these longer-term projects reduces capital available to develop our near-term portfolio. This limits our flexibility to adjust capital expenditures to changes in cash flow, particularly in these times of low commodity prices.

Therefore, we are pursuing a partner to participate in our Lower Tertiary projects in the Gulf of Mexico. The proceeds from such a transaction would support the liquidity provided by our operating cash flow and credit lines. Furthermore, our share of the ongoing capital commitments would be reduced, which would provide additional liquidity as well. Additionally, these proceeds and our other available cash resources position us with adequate capital to quickly increase exploration and development activities once commodity prices show signs of long-term improvement.

Capital Expenditures

In August 2009, we provided guidance for our 2009 capital expenditures. At that time, we estimated total capital expenditures would range from $4.5 billion to $5.2 billion. This estimate is significantly lower than our 2008 capital expenditures, and coincides with the significant decline in current oil, gas and NGL prices, as well as the near-term price expectations. Based upon current oil and natural gas price expectations, we anticipate having adequate capital resources to fund this planned level of 2009 capital expenditures.

Recently Issued Accounting Standards Not Yet Adopted

In December 2008, the Financial Accounting Standards Board (FASB) updated Accounting Standards Codification (ASC) Topic 715 Compensation Retirement Benefits, regarding employers disclosures about postretirement benefit plan assets. This ASC update requires additional disclosures about the types of assets and associated risks in an employer s defined benefit pension or other postretirement plan. It is effective for fiscal years ending after December 15, 2009. We are evaluating the impact the adoption of this ASC update will have on our financial statement disclosures. However, our adoption of this ASC update will not affect our current accounting for our pension and postretirement plans.

Modernization of Oil and Gas Reporting

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. Additionally, on two separate occasions in October 2009, the SEC issued certain compliance and disclosure interpretations of its oil and gas rules. The disclosure revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting our reserve disclosures, including the comparability of our reserves disclosures with those of our peer companies:

Pricing mechanism for oil and gas reserves estimation - The SEC s current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

Reasonable certainty - The SEC s current definition of proved oil and gas reserves incorporate certain specific concepts such as lowest known hydrocarbons, which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of reliable technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, we expect our proved reserve estimates will increase upon adoption of the revised rules. However, we are not able to estimate the magnitude of the potential increase at this time.

Unproved reserves - The SEC s current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. We have not yet determined whether we will disclose our probable and possible reserves in documents filed with the SEC.

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

Commodity Price Risk

We have various financial price collars to set minimum and maximum prices on a portion of our 2009 gas production. The key terms to the price collars we had entered into prior to the filing of our 2008 Annual Report on Form 10-K are included in Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Annual Report on Form 10-K.

Table of Contents

In addition, subsequent to the preparation of our 2008 Annual Report on Form 10-K, we entered into additional gas price swaps related to a portion of our third and fourth quarter 2009 gas production. The key terms to these gas financial contracts as of November 2, 2009 are presented in the following table.

Gas Price Swap Contracts

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Third Quarter 2009	81,522	$ 4.01
Fourth Quarter 2009	800,000	$ 4.79

Subsequent to the preparation of our 2008 Annual Report on Form 10-K, we also entered into various gas price swaps and oil price collars related to our 2010 production. The contracts relate to the same amounts of daily production in each 2010 quarter. The key terms to these financial contracts as of November 2, 2009 are presented in the following tables.

Gas Price Swap Contracts

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
2010	1,085,000	$ 6.18

Oil Price Collar Contracts

		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
2010	66,000	$ 65.00 - $70.00	$66.97	$ 90.35 - $103.30	$95.98

The fair values of our commodity financial hedging instruments are largely determined by estimates of the forward curves of the Inside FERC Henry Hub for gas instruments and West Texas Intermediate for oil instruments. Based on the amount of volumes subject to our gas price swaps and collars at November 2, 2009, a 10% increase in these forward curves would have decreased the fair value of our gas price swaps and collars by approximately $245 million. A 10% increase in the forward curves associated with our oil collars would have decreased the fair value of these instruments by approximately $110 million.

Interest Rate Risk

At September 30, 2009, we had debt outstanding of $7.4 billion. Of this amount, $6.0 billion, or 81%, bears interest at fixed rates averaging 7.24%. Additionally, we had $1.4 billion of outstanding commercial paper, bearing interest at floating rates that averaged 0.32%.

We also have interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. The key terms to these interest rate swaps are included in Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Annual Report on Form 10-K.

In addition, subsequent to the preparation of our 2008 Annual Report on Form 10-K, we entered into additional interest rate swaps that have a total notional value of $800 million as of November 2, 2009. These new swaps include a swap with a $100 million notional amount in which we receive a fixed rate of 1.90% and pay a floating rate based upon the Federal funds rate. This swap expires on August 3, 2012.

The remainder of the new swaps with a total notional value of $700 million expire on September 30, 2011. Under the terms of these swaps, we will net settle these contracts in September 2011. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.99% and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041.

Table of Contents

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 November 2, 2009, a 10% increase in these forward curves would have increased the fair value of our interest rate derivative instruments by approximately $40 million.

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, 2009 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 2009 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

Table of Contents

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 2008 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 2008 Annual Report on Form 10-K.

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

No shares have been repurchased during the first nine months of 2009.

As of September 30, 2009, we are authorized to repurchase 50.3 million common shares. This amount is comprised of 45.5 million remaining common shares authorized to be repurchased under a 50 million share repurchase program and 4.8 million common shares authorized to be repurchased in 2009 under an annual repurchase program.

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

None.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

Item 5. ***Other Information***

None.

Item 6. ***Exhibits***

Exhibit Number	Description
10.1	364-Day Credit Agreement dated as of November 3, 2009, among Registrant as Borrower, Bank of America, N.A. as Administrative Agent, JPMorgan Chase Bank, N.A. as Syndication Agent, and The Other Lenders party thereto, Banc of America Securities LLC and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Book Managers for the $700 Million Short-Term Credit Facility.
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Danny J. Heatly, Senior Vice President - Accounting and Chief Accounting Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Danny J. Heatly, Senior Vice President - Accounting and Chief Accounting Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema 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

Table of Contents

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 5, 2009	/s/ Danny J. Heatly Danny J. Heatly *Senior Vice President - Accounting and Chief Accounting Officer*

49

INDEX TO EXHIBITS

Exhibit Number	Description
10.1	364-Day Credit Agreement dated as of November 3, 2009, among Registrant as Borrower, Bank of America, N.A. as Administrative Agent, JPMorgan Chase Bank, N.A. as Syndication Agent, and The Other Lenders party thereto, Banc of America Securities LLC and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Book Managers for the $700 Million Short-Term Credit Facility.
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Danny J. Heatly, Senior Vice President - Accounting and Chief Accounting Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Danny J. Heatly, Senior Vice President - Accounting and Chief Accounting Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema 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