DEVON ENERGY CORP/DE
Form 10-Q
May 07, 2009

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

(Mark One)

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

For the quarterly period ended March 31, 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 o 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

On April 30, 2009, 443.9 million shares of common stock were outstanding.

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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 division of Devon encompassing oil and gas properties located in Canada.

Domestic means the properties of Devon 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 division 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 properties of Devon in the Gulf of Mexico.

U.S. Onshore means the properties of Devon in the continental United States.

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

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

- energy markets, including the supply and demand for oil, gas, NGLs and other products or services, 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 Devon s 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.

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PART I. Financial Information

Item 1. Consolidated Financial Statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	March 31, 2009 (Unaudited)	December 31, 2008
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 397	$ 379
Accounts receivable	1,221	1,412
Income taxes receivable	106	334
Derivative financial instruments, at fair value	327	282
Other current assets	325	277
Total current assets	2,376	2,684
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($4,186 and $4,540 excluded from amortization in 2009 and 2008, respectively)	56,784	55,657
Less accumulated depreciation, depletion and amortization	39,568	32,683
Property and equipment, net	17,216	22,974
Goodwill	5,509	5,579
Other long-term assets, including $177 million and $199 million at fair value in 2009 and 2008, respectively	622	671
Total assets	$ 25,723	$ 31,908
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,261	$ 1,819
Revenues and royalties due to others	373	496
Short-term debt	1,073	180
Current portion of asset retirement obligations, at fair value	157	138
Accrued expenses and other current liabilities	370	502
Total current liabilities	3,234	3,135
Long-term debt	5,851	5,661
Asset retirement obligations, at fair value	1,340	1,347
Other long-term liabilities	992	1,026
Deferred income taxes	1,364	3,679

Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 443.9 million and 443.7 million shares in 2009 and 2008, respectively	44	44
Additional paid-in capital	6,310	6,257
Retained earnings	6,347	10,376
Accumulated other comprehensive income	241	383
Total stockholders equity	12,942	17,060
Commitments and contingencies (Note 8)		
Total liabilities and stockholders equity	$ 25,723	$ 31,908

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31, 2009	2008
	(Unaudited) (In millions, except per share amounts)	
Revenues:		
Oil sales	$ 454	$ 1,250
Gas sales	913	1,630
NGL sales	136	328
Net gain (loss) on oil and gas derivative financial instruments	154	(788)
Marketing and midstream revenues	371	555
Total revenues	2,028	2,975
Expenses and other income, net:		
Lease operating expenses	524	506
Production taxes	42	134
Marketing and midstream operating costs and expenses	229	382
Depreciation, depletion and amortization of oil and gas properties	599	737
Depreciation and amortization of non-oil and gas properties	70	57
Accretion of asset retirement obligations	24	22
General and administrative expenses	166	148
Interest expense	83	102
Change in fair value of other financial instruments	(5)	16
Reduction of carrying value of oil and gas properties	6,516	
Other expense (income), net	7	(21)
Total expenses and other income, net	8,255	2,083
(Loss) earnings from continuing operations before income taxes	(6,227)	892
Income tax (benefit) expense:		
Current	2	103
Deferred	(2,271)	138
Total income tax (benefit) expense	(2,269)	241
(Loss) earnings from continuing operations	(3,958)	651
Discontinued operations:		
(Loss) earnings from discontinued operations before income taxes	(1)	189
Income tax expense		91
(Loss) earnings from discontinued operations	(1)	98
Net (loss) earnings	(3,959)	749
Preferred stock dividends		2

Net (loss) earnings applicable to common stockholders	$ (3,959)	$ 747
Basic net (loss) earnings per share:		
(Loss) earnings from continuing operations	$ (8.92)	$ 1.46
Earnings from discontinued operations		0.22
Net (loss) earnings	$ (8.92)	$ 1.68
Diluted net (loss) earnings per share:		
(Loss) earnings from continuing operations	$ (8.92)	$ 1.44
Earnings from discontinued operations		0.22
Net (loss) earnings	$ (8.92)	$ 1.66
Weighted average common shares outstanding:		
Basic	444	445
Diluted	444	449

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2009	2008
	(Unaudited) (In millions)	
Net (loss) earnings	$ (3,959)	$ 749
Foreign currency translation:		
Change in cumulative translation adjustment	(161)	(382)
Income tax benefit	11	17
Total	(150)	(365)
Pension and postretirement benefit plans:		
Recognition of net actuarial loss and prior service cost in net (loss) earnings	12	4
Income tax expense	(4)	(1)
Total	8	3
Other comprehensive loss, net of tax	(142)	(362)
Comprehensive (loss) income	$ (4,101)	$ 387

See accompanying notes to consolidated financial statements.

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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)			
Three Months Ended March 31, 2009:								
Balance as of December 31, 2008		444	$ 44	$ 6,257	$ 10,376	$ 383	$	$ 17,060
Net loss					(3,959)			(3,959)
Other comprehensive loss						(142)		(142)
Stock option exercises				4				4
Common stock repurchased							(2)	(2)
Common stock retired				(2)			2	
Common stock dividends					(70)			(70)
Share-based compensation				49				49
Share-based compensation tax benefits				2				2
Balance as of March 31, 2009		444	$ 44	$ 6,310	$ 6,347	$ 241	$	$ 12,942
Three Months Ended March 31, 2008:								
Balance as of December 31, 2007	$ 1	444	$ 44	$ 6,743	$ 12,813	$ 2,405	$	$ 22,006
Net earnings					749			749
Other comprehensive loss						(362)		(362)
Stock option exercises		3	1	78			(3)	76
Common stock repurchased							(65)	(65)
Common stock retired		(1)		(68)			68	
Common stock dividends					(71)			(71)
Preferred stock dividends					(2)			(2)
Share-based compensation				40				40
Share-based compensation tax benefits				27				27
Balance as of March 31, 2008	$ 1	446	$ 45	$ 6,820	$ 13,489	$ 2,043	$	$ 22,398

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31,	
	2009	2008
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net (loss) earnings	$ (3,959)	$ 749
Loss (earnings) from discontinued operations, net of tax	1	(98)
Adjustments to reconcile (loss) earnings from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	669	794
Deferred income tax (benefit) expense	(2,271)	138
Reduction of carrying value of oil and gas properties	6,516	
Net unrealized (gain) loss on oil and gas derivative financial instruments	(36)	780
Other noncash charges	68	74
Net decrease (increase) in working capital	83	(377)
Decrease (increase) in long-term other assets	2	(11)
(Decrease) increase in long-term other liabilities	(31)	21
Cash provided by operating activities continuing operations	1,042	2,070
Cash provided by operating activities discontinued operations	5	185
Net cash provided by operating activities	1,047	2,255
Cash flows from investing activities:		
Proceeds from sales of property and equipment	1	105
Capital expenditures	(2,019)	(1,862)
Purchases of short-term investments		(50)
Sales of long-term and short-term investments	2	270
Cash used in investing activities continuing operations	(2,016)	(1,537)
Cash used in investing activities discontinued operations	(14)	(24)
Net cash used in investing activities	(2,030)	(1,561)
Cash flows from financing activities:		
Proceeds from borrowings of long-term debt, net of issuance costs	1,187	
Credit facility repayments		(1,450)
Credit facility borrowings		920
Net commercial paper (repayments) borrowings	(111)	442
Debt repayments	(1)	(41)
Proceeds from stock option exercises	4	74
Repurchases of common stock		(64)
Dividends paid on common and preferred stock	(70)	(73)

Excess tax benefits related to share-based compensation	2	27
Net cash provided by (used in) financing activities	1,011	(165)
Effect of exchange rate changes on cash	(11)	(19)
Net increase in cash and cash equivalents	17	510
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)	$ 401	$ 1,883

See accompanying notes to consolidated financial statements.

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

1. Summary of Significant Accounting Policies

The accompanying unaudited consolidated financial statements and notes of Devon Energy Corporation (Devon) have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted. The accompanying consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes included in Devon s 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 March 31, 2009 and Devon s results of operations and cash flows for the three-month periods ended March 31, 2009 and 2008.

Recently Issued Accounting Standards Not Yet Adopted

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets. Staff Position 132(R)-1 amends FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits, to require additional disclosures about the types of assets and associated risks in an employer s defined benefit pension or other postretirement plan. Staff Position 132(R)-1 is effective for fiscal years ending after December 15, 2009. Devon is evaluating the impact the adoption of Staff Position 132(R)-1 will have on its financial statement disclosures. However, Devon s adoption of Staff Position 132(R)-1 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. The 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.

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 alternative technologies to

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

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. 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.

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)	
March 31, 2009:			
Gas price collars	Derivative financial instruments, current	$ 291	$
Interest rate swaps	Derivative financial instruments, current	36	
Interest rate swaps	Long-term other assets	57	
Total derivatives		$ 384	$
December 31, 2008:			
Gas price collars	Derivative financial instruments, current	$ 255	$
Interest rate swaps	Derivative financial instruments, current	27	
Interest rate swaps	Long-term other assets	77	
Total derivatives		$ 359	$

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

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.

	Statement of Operations Caption	Three Months Ended March 31, 2009	2008
		(In millions)	
Cash settlement receipts (payments):			
Gas price collars	Net gain (loss) on oil and gas derivative financial instruments	$ 118	$
Gas price swaps	Net gain (loss) on oil and gas derivative financial instruments		(8)
Interest rate swaps	Change in fair value of other financial instruments	16	
Total cash settlements		134	(8)
Unrealized gains (losses):			
Oil price collars	Net gain (loss) on oil and gas derivative financial instruments		(1)
Gas price collars	Net gain (loss) on oil and gas derivative financial instruments	36	(408)
Gas price swaps	Net gain (loss) on oil and gas derivative financial instruments		(371)
Interest rate swaps	Change in fair value of other financial instruments	(11)	
Embedded option	Change in fair value of other financial instruments		97
Total unrealized gains (losses)		25	(683)
Net gain (loss) recognized on statement of operations		$ 159	$ (691)

3. Other Current Assets

The components of other current assets include the following:

	March 31, 2009	December 31, 2008
	(In millions)	
Inventories	$ 244	$ 195
Prepaid assets	52	49
Other	29	33
Other current assets	$ 325	$ 277

4. Property and Equipment and Asset Retirement Obligations

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 10.

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

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

	Three Months Ended March 31, 2009	2008
	(In millions)	
ARO as of beginning of period	$ 1,485	$ 1,318
Liabilities incurred	8	16
Liabilities settled	(26)	(25)
Revision of estimated obligation	23	140
Accretion expense on discounted obligation	24	22
Foreign currency translation adjustment	(17)	(26)
ARO as of end of period	1,497	1,445
Less current portion	157	68
ARO, long-term	$ 1,340	$ 1,377

5. 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 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 March 31, 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 3, 2009 maturity	700
Total credit facility capacity	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	894
Outstanding letters of credit	112
Total available capacity	$ 2,344

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 March 31, 2009, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at March 31, 2009, as calculated pursuant to the terms of the agreement, was 21.3%.

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

Commercial Paper

Subsequent to the $1.0 billion commercial paper repayment in January 2009, Devon utilized additional commercial paper borrowings of $894 million to fund capital expenditure payments in excess of first quarter cash generated by operating activities. As of March 31, 2009, Devon s average borrowing rate on its $894 million of commercial paper debt was 0.70%.

6. 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 periods ended March 31, 2009 and 2008.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2009	**2008**	**2009**	**2008**
Net periodic benefit cost:				
Service cost	$ 11	$ 10	$	$
Interest cost	14	14	1	2
Expected return on plan assets	(9)	(13)		
Amortization of prior service cost	1			
Net actuarial loss	11	4		
Net periodic benefit cost	28	15	1	2
Other comprehensive income:				
Recognition of prior service cost in net periodic benefit cost	(1)			
Recognition of net actuarial loss in net periodic benefit cost	(11)	(4)		
Total recognized	$ 16	$ 11	$ 1	$ 2

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 March 31, 2009, Devon has contributed $14 million to its defined benefit pension plans and $1 million to its defined benefit postretirement plans.

7. Stockholders Equity

Stock Repurchases

During the first quarter of 2008, Devon repurchased 0.8 million shares for $64 million, or $79.37 per share. These repurchases were made under Devon s ongoing, annual stock repurchase program approved by its Board of Directors. No such repurchases were made during the first quarter of 2009.

Dividends

Devon paid common stock dividends of $70 million and $71 million (quarterly rates of $0.16 per share) in the first quarter of 2009 and 2008, respectively. Devon paid preferred stock dividends of $2 million in the first quarter of 2008. Devon redeemed all 1.5 million outstanding shares of its preferred stock on June 20, 2008.

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

8. Commitments and Contingencies

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

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act (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 March 31, 2009, Devon s balance sheet included $2 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 and, 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. Deep water leases issued in 1998 and 1999 did not include price thresholds.

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The U.S. House of Representatives in January 2007 passed legislation that would have required companies to renegotiate the 1998 and 1999 leases as a condition of securing future federal leases. This legislation was not passed by the U.S. Senate. However, Congress may consider similar legislation in the future. 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 is subject to further appeals.

As of March 31, 2009, Devon had $82 million accrued for potential royalties on various deep water leases. Due to the uncertainty of this issue caused by the favorable federal court decisions and potential Congressional actions, Devon has ceased accruing additional royalties on its affected leases. Devon will continue to monitor developments and adjust its accruals as necessary.

Other Matters

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

9. 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 March 31, 2009 and December 31, 2008.

	As of March 31, 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	$ 120	$ 120	$	$	$ 120
Gas price collars	$ 291	$ 291	$	$ 291	$
Interest rate swaps	$ 93	$ 93	$	$ 93	$
Debt	$(6,924)	$(7,079)	$(894)	$(6,185)	$
Asset retirement obligation	$(1,497)	$(1,497)	$	$	$(1,497)

	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 obligation	$(1,485)	$(1,485)	$	$	$ (1,485)

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
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Included below is a summary of the changes in Devon s Level 3 fair value measurements during the first quarter of 2009 (in millions).

Beginning balance	$ 122
Redemptions of principal	(2)
Ending balance	$ 120

10. 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.

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.

11. Discontinued Operations

Operating revenues related to Devon s discontinued operations totaled $205 million in the three months ended March 31, 2008.

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

	Devon s Consolidated Balance Sheet Caption	March 31, 2009	December 31, 2008
		(In millions)	
Assets:			
Cash	Other current assets	$ 4	$ 5
Other current assets	Other current assets	20	22
Total current assets	Other current assets	$ 24	$ 27
Long-term assets property and equipment, net of accumulated depreciation, depletion and amortization	Other long-term assets	$ 36	$ 19
Liabilities:			
Accounts payable trade	Other current liabilities	$ 15	$ 7
Accrued expenses and other current liabilities	Other current liabilities	5	6
Total current liabilities	Other current liabilities	$ 20	$ 13

12. (Loss) Earnings Per Share

The following table reconciles (loss) earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted (loss) earnings per share for the three-month periods ended March 31, 2009 and 2008. Because a net loss from continuing operations was generated during the three-month period ended March 31, 2009, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share from continuing operations reported in the accompanying 2009 statement of operations is the same as the basic loss per share amount.

	Net (Loss) Earnings Applicable to Common Stockholders	Weighted Average Common Shares Outstanding	Net (Loss) Earnings per Share
	(In millions, except per share amounts)		
Three Months Ended March 31, 2009:			
Basic and diluted loss per share	$ (3,958)	444	$ (8.92)
Three Months Ended March 31, 2008:			
Earnings from continuing operations	$ 651		
Less preferred stock dividends	(2)		

Basic earnings per share	649	445	$ 1.46
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		4	
Diluted earnings per share	$ 649	449	$ 1.44

Certain options to purchase shares of Devon s common stock are excluded from the dilution calculations because the options are antidilutive. These excluded options totaled 8.9 million and 1.8 million during the three-month periods ended March 31, 2009 and 2008.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
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13. Segment Information

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

	U.S.	Canada	International	Total
		(In millions)		
As of March 31, 2009:				
Current assets	$ 1,557	$ 464	$ 355	$ 2,376
Property and equipment, net	11,954	4,390	872	17,216
Goodwill	3,046	2,395	68	5,509
Other long-term assets	310	61	251	622
Total assets	$ 16,867	$ 7,310	$ 1,546	$ 25,723
Current liabilities	$ 2,522	$ 403	$ 309	$ 3,234
Long-term debt	2,872	2,979		5,851
Asset retirement obligation, long-term	708	532	100	1,340
Other long-term liabilities	951	38	3	992
Deferred income taxes	448	851	65	1,364
Stockholders equity	9,366	2,507	1,069	12,942
Total liabilities and stockholders equity	$ 16,867	$ 7,310	$ 1,546	$ 25,723

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended March 31, 2009:				
Revenues:				
Oil sales	$ 150	$ 177	$ 127	$ 454
Gas sales	676	236	1	913
NGL sales	112	24		136
Net gain on oil and gas derivative financial instruments	154			154
Marketing and midstream revenues	364	7		371
Total revenues	1,456	444	128	2,028
Expenses and other income, net:				
Lease operating expenses	313	177	34	524
Production taxes	32		10	42
Marketing and midstream operating costs and expenses	224	4	1	229
Depreciation, depletion and amortization of oil and gas properties	440	120	39	599
Depreciation and amortization of non-oil and gas properties	64	6		70
Accretion of asset retirement obligation	14	9	1	24
General and administrative expenses	137	29		166
Interest expense	27	56		83
Change in fair value of other financial instruments	(5)			(5)
Reduction of carrying value of oil and gas properties	6,408		108	6,516
Other expense (income), net	(3)	10		7
Total expenses and other income, net	7,651	411	193	8,255
(Loss) earnings from continuing operations before income taxes	(6,195)	33	(65)	(6,227)
Income tax (benefit) expense:				
Current	(10)	2	10	2
Deferred	(2,279)	7	1	(2,271)
Total income tax (benefit) expense	(2,289)	9	11	(2,269)
(Loss) earnings from continuing operations	(3,906)	24	(76)	(3,958)
Loss from discontinued operations			(1)	(1)
Net (loss) earnings applicable to common stockholders	$ (3,906)	$ 24	$ (77)	$ (3,959)
Capital expenditures, before revision of future ARO	$ 1,148	$ 301	$ 73	$ 1,522
Revision of future ARO	37	(15)	1	23

Capital expenditures, continuing operations	$ 1,185	$ 286	$ 74	$ 1,545

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

	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended March 31, 2008:				
Revenues:				
Oil sales	$ 443	$ 340	$ 467	$ 1,250
Gas sales	1,263	389	5	1,630
NGL sales	266	62		328
Net loss on oil and gas derivative financial instruments	(788)			(788)
Marketing and midstream revenues	542	13		555
Total revenues	1,699	804	472	2,975
Expenses and other income, net:				
Lease operating expenses	266	194	46	506
Production taxes	79	1	54	134
Marketing and midstream operating costs and expenses	377	5		382
Depreciation, depletion and amortization of oil and gas properties	460	211	66	737
Depreciation and amortization of non-oil and gas properties	51	6		57
Accretion of asset retirement obligation	11	10	1	22
General and administrative expenses	114	34		148
Interest expense	52	50		102
Change in fair value of other financial instruments	16			16
Other income, net	(6)	(5)	(10)	(21)
Total expenses and other income, net	1,420	506	157	2,083
Earnings from continuing operations before income taxes	279	298	315	892
Income tax expense:				
Current	46	18	39	103
Deferred	50	48	40	138
Total income tax expense	96	66	79	241
Earnings from continuing operations	183	232	236	651
Discontinued operations:				
Earnings from discontinued operations before income taxes			189	189
Income tax expense			91	91
Earnings from discontinued operations			98	98
Net earnings	183	232	334	749

Preferred stock dividends	2			2
Net earnings applicable to common stockholders	$ 181	$ 232	$ 334	$ 747
Capital expenditures, continuing operations	$ 1,311	$ 516	$ 151	$ 1,978
Revision of future ARO	70	73	(3)	140
Capital expenditures, continuing operations	$ 1,381	$ 589	$ 148	$ 2,118

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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14. Supplemental Information to Statements of Cash Flows

Additional information related to Devon s cash flows for the three-month periods ended March 31, 2009 and 2008 are presented below:

	Three Months Ended March 31, 2009	2008
	(In millions)	
Net decrease (increase) in working capital:		
Decrease (increase) in accounts receivable	$ 206	$ (328)
Decrease (increase) in other current assets	185	(39)
(Decrease) increase in accounts payable	(25)	38
(Decrease) increase in revenues and royalties due to others	(117)	119
Decrease in other current liabilities	(166)	(167)
Net decrease (increase) in working capital	$ 83	$ (377)
Supplementary cash flow data continuing and discontinued operations:		
Interest paid net of capitalized interest	$ 98	$ 136
Income taxes (received) paid	$ (177)	$ 83

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

The following discussion addresses material changes in our results of operations and capital resources and uses for the three-month period ended March 31, 2009, compared to the three-month period ended March 31, 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 quarter of 2009. The Henry Hub natural gas index decreased 29% from the fourth quarter of 2008 to the first quarter of 2009, and 39% from the first quarter of 2008. Additionally, although oil index prices have improved slightly since the end of 2008, the West Texas Intermediate oil index dropped 56% from the first quarter of 2008 to the first quarter of 2009.

As a result, our earnings for the first three months ended March 31, 2009 were negatively impacted. During the first quarter of 2009, we generated a net loss of $4.0 billion, or $8.92 per diluted share, representing a significant change compared to the same period of 2008. The loss in the 2009 quarter was the result of noncash impairments of our oil and gas properties that totaled $4.2 billion, net of income taxes. Substantially all of this noncash charge was the result of the continuing drop in natural gas prices in the first quarter.

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

- Production increased 6% to 62 million Boe.
- The combined realized price without hedges for oil, gas and NGLs decreased 56% to $24.39 per Boe.
- Marketing and midstream operating profit decreased 18% to $142 million.
- Per unit operating costs decreased 16% to $9.19 per Boe.
- Oil and gas hedges generated a net gain of $154 million in the first quarter of 2009 and a net loss of $788 million in the first quarter of 2008. Included in these amounts were cash receipts of $118 million and payments of $8 million, respectively.
- General and administrative expenses increased 12% to $166 million.
- Operating cash flow decreased 54% to $1.0 billion in the first quarter of 2009.
- Cash spent on capital expenditures was approximately $2.0 billion in the first quarter of 2009. Approximately half this amount was funded with operating cash flow and the remainder was funded with commercial paper borrowings.

Additionally, 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.

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 April 30, 2009, we had unused lines of credit totaling $2.2 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.

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Results of Operations

Revenues

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

	Total Three Months Ended March 31,		
	2009	2008	Change(2)
Production			
Oil (MMBbls)	13	14	-5%
Gas (Bcf)	245	223	+10%
NGLs (MMBbls)	7	7	+6%
Total (MMBoe)(1)	62	58	+6%
Realized prices without hedges			
Oil (per Bbl)	$ 33.61	$ 88.23	-62%
Gas (per Mcf)	$ 3.73	$ 7.31	-49%
NGLs (per Bbl)	$ 18.60	$ 47.40	-61%
Combined (per Boe)(1)	$ 24.39	$ 55.07	-56%
Revenues ($ in millions)			
Oil sales	$ 454	$ 1,250	-64%
Gas sales	913	1,630	-44%
NGL sales	136	328	-58%
Total	$ 1,503	$ 3,208	-53%

	Domestic Three Months Ended March 31,		
	2009	2008	Change(2)
Production			
Oil (MMBbls)	4	4	-12%
Gas (Bcf)	192	171	+12%
NGLs (MMBbls)	6	6	+8%
Total (MMBoe)(1)	43	39	+9%
Realized prices without hedges			
Oil (per Bbl)	$ 36.89	$ 95.70	-61%
Gas (per Mcf)	$ 3.53	$ 7.24	-51%
NGLs (per Bbl)	$ 17.53	$ 44.86	-61%
Combined (per Boe)(1)	$ 22.11	$ 49.84	-56%
Revenues ($ in millions)			
Oil sales	$ 150	$ 443	-66%
Gas sales	676	1,236	-45%
NGL sales	112	266	-58%

Total	$ 938	$ 1,945	-52%

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	Canada		
	Three Months Ended March 31,		
	2009	2008	Change[2]
Production			
Oil (MMBbls)	6	5	+35%
Gas (Bcf)	53	52	+2%
NGLs (MMBbls)	1	1	-5%
Total (MMBoe)[1]	16	14	+13%
Realized prices without hedges			
Oil (per Bbl)	$ 27.89	$ 72.68	-62%
Gas (per Mcf)	$ 4.48	$ 7.53	-41%
NGLs (per Bbl)	$ 25.85	$ 62.67	-59%
Combined (per Boe)[1]	$ 27.21	$ 55.42	-51%
Revenues ($ in millions)			
Oil sales	$ 177	$ 340	-48%
Gas sales	236	389	-39%
NGL sales	24	62	-61%
Total	$ 437	$ 791	-45%

	International		
	Three Months Ended March 31,		
	2009	2008	Change[2]
Production			
Oil (MMBbls)	3	5	-36%
Gas (Bcf)			-45%
NGLs (MMBbls)			N/M
Total (MMBoe)[1]	3	5	-36%
Realized prices without hedges			
Oil (per Bbl)	$ 41.00	$ 96.08	-57%
Gas (per Mcf)	$ 3.47	$ 8.41	-59%
NGLs (per Bbl)	$	$	N/M
Combined (per Boe)[1]	$ 40.68	$ 95.24	-57%
Revenues ($ in millions)			
Oil sales	$ 127	$ 467	-73%
Gas sales	1	5	-77%
NGL sales			N/M
Total	$ 128	$ 472	-73%

(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 March 31, 2009 and 2008.

	Oil	Gas	NGLs	Total
		(In millions)		
2008 sales	$ 1,250	$ 1,630	$ 328	$ 3,208
Changes due to volumes	(59)	159	19	119
Changes due to prices	(737)	(876)	(211)	(1,824)
2009 sales	$ 454	$ 913	$ 136	$ 1,503

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Oil Sales

Oil sales decreased $737 million in the first quarter of 2009 as a result of a 62% decrease in our realized price without hedges. The average NYMEX West Texas Intermediate index price decreased 56% during the same time period, accounting for the majority of the decrease.

Oil sales decreased $59 million in the first quarter of 2009 due to a one million barrel decrease in production. Our International production decreased approximately two million barrels due to reaching certain cost recovery thresholds of our carried interest in Azerbaijan. Also, we deferred approximately 0.3 million barrels of Gulf of Mexico oil production due to hurricanes. These decreases were partially offset by additional production of almost two million barrels from our Jackfish operation in Canada.

Gas Sales

Gas sales decreased $876 million during the first quarter of 2009 as a result of a 49% 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 22 Bcf increase in production during the first quarter of 2009 caused gas sales to increase by $159 million. Our drilling and development program in the Barnett Shale field in north Texas contributed 15 Bcf to the gas production increase. This increase and the effect of new drilling and development in our other North American properties were partially offset by natural production declines, mainly in the Gulf of Mexico, and the deferral of two Bcf of production due to hurricane damage suffered in the third quarter of 2008.

NGL Sales

NGL sales decreased $211 million during the first quarter of 2009 as a result of a 61% 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.

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 first quarters 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 first quarters of 2009 and 2008. The prices do not include the effects of unrealized gains and losses.

	Three Months Ended March 31,	
	2009	**2008**
	(In millions)	
Cash settlements:		
Gas price swaps	$	$ (8)
Gas price collars	118	
Total cash settlements received (paid)	118	(8)
Unrealized gains (losses) on fair value changes:		
Gas price swaps		(371)
Gas price collars	36	(408)
Oil price collars		(1)
Total unrealized gains (losses) on fair value changes	36	(780)
Net gain (loss) on oil and gas derivative financial instruments	$ 154	$ (788)

Three Months Ended March 31, 2009

	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 33.61	$ 3.73	$ 18.60	$ 24.39
Cash settlements of hedges		0.48		1.91
Realized price, including cash settlements	$ 33.61	$ 4.21	$ 18.60	$ 26.30

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	Three Months Ended March 31, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 88.23	$ 7.31	$ 47.40	$ 55.07
Cash settlements of hedges		(0.04)		(0.14)
Realized price, including cash settlements	$ 88.23	$ 7.27	$ 47.40	$ 54.93

In the first quarter of 2009, our derivative financial instruments were comprised of gas price collars. In the first quarter of 2008, our derivative financial instruments included gas price swaps and oil and gas price collars. For the price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. The price collars set a floor and ceiling price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we cash-settle the difference with the counterparty to the collars. Cash settlements as presented in the tables above represent realized losses or gains related to our price swaps and collars.

During the first quarter of 2009, we received $118 million, or $0.48 per Mcf from counterparties to settle our gas price collars. During the first quarter of 2008, we paid $8 million, or $0.04 per Mcf, to counterparties to settle our gas price swaps and collars.

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 and/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 collars at March 31, 2009, a 10% increase in these forward curves would have decreased our first quarter 2009 unrealized gain for our gas collar derivative financial instruments by approximately $29 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 eight separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade . The threshold for collateral posting decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of March 31, 2009, the credit ratings of all our counterparties were investment grade.

During the first quarter of 2009, we recognized a $36 million unrealized gain as a result of decreases in the Inside FERC Henry Hub forward curve subsequent to December 31, 2008.

During the first quarter of 2008, we recognized unrealized losses totaling $779 million related to our gas derivative instruments. These losses resulted primarily from a significant increase in the Inside FERC Henry Hub forward curve subsequent to our contract trade dates.

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 months ended March 31, 2009 and 2008 are shown in the table below.

	Three Months Ended March 31, 2009	2008	Change(1)
	($ in millions)		
Marketing and midstream:			
Revenues	$ 371	$ 555	-33%
Operating costs and expenses	229	382	-40%
Operating profit	$ 142	$ 173	-18%

(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 first quarter of 2009, marketing and midstream revenues decreased $184 million and operating costs and expenses also decreased $153 million, causing operating profit to decrease $31 million. Revenues and expenses decreased primarily due to lower natural gas and NGL prices, partially offset by increased gas pipeline throughput.

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 months ended March 31, 2009 and 2008 are shown in the table below.

	Three Months Ended March 31, 2009	2008	Change(1)
	($ in millions)		
Production and operating expenses:			
Lease operating expenses	$ 524	$ 506	+4%
Production taxes	42	134	-68%
Total production and operating expenses	$ 566	$ 640	-12%
Production and operating expenses per Boe:			
Lease operating expenses	$ 8.50	$ 8.69	-2%
Production taxes	0.69	2.30	-70%
Total production and operating expenses per Boe	$ 9.19	$ 10.99	-16%

(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 increased $18 million in the first quarter of 2009. LOE increased $29 million due to our 6% growth in production. Higher per-unit costs associated with our thermal heavy oil production from our Jackfish operations in Canada and new oil production from Brazil caused LOE to increase an additional $24 million. Until these large-scale projects reach their target full-scale production levels, their per-unit operating costs will be higher than the per-unit costs for our overall portfolio of producing properties. LOE also increased $7 million due to additional costs associated with damages of certain of our facilities and transportation systems that were caused by Hurricane Ike in the third quarter of 2008. These increases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollar. The exchange rate caused LOE to decrease $43 million and was the main contributor to the decrease in LOE per Boe.

Production Taxes

The following table details the changes in production taxes between the three months ended March 31, 2009 and 2008. The majority of our production taxes are assessed on our U.S. onshore properties and are 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 following table primarily relate to changes in oil, gas and NGL revenues from our U.S. onshore and International properties.

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	Three Months Ended March 31, (In millions)
2008 production taxes	$ 134
Change due to revenues	(71)
Change due to rate	(21)
2009 production taxes	$ 42

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 months ended March 31, 2009 and 2008 are shown in the table below.

	Three Months Ended March 31,		
	2009	2008	Change(1)
Total production volumes (MMBoe)	62	58	+6%
DD&A rate ($ per Boe)	$ 9.72	$ 12.64	-23%
DD&A expense ($ in millions)	$ 599	$ 737	-19%

(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 months ended March 31, 2009 and 2008.

	Three Months Ended March 31, (In millions)
2008 DD&A	$ 737
Change due to volumes	42
Change due to rate	(180)
2009 DD&A	$ 599

The 6% production increase during the first quarter of 2009 caused oil and gas property related DD&A to increase $42 million. Oil and gas property-related DD&A decreased $180 million due to a 23% decrease in the DD&A rate. The largest contributors to the rate decrease were reductions of the carrying values of certain of our oil and gas properties recognized in the fourth quarter of 2008. These reductions totaled $10.4 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 contributed to the rate decrease. These decreases were offset by the effects of inflationary pressure on costs incurred during most of 2008 and the transfer of previously unproved costs to the depletable base as a result of drilling activities.

General and Administrative Expenses (G&A)

The following schedule includes the components of G&A expense for the three-month periods ended March 31, 2009 and 2008.

	Three Months Ended March 31,		
	2009	2008	Change (1)
	(In millions)		
Gross G&A	$ 305	$ 277	+10%
Capitalized G&A	(104)	(99)	+5%
Reimbursed G&A	(35)	(30)	+17%
Net G&A	$ 166	$ 148	+12%

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

Gross G&A increased $28 million in the first quarter of 2009 compared to the same period of 2008. The largest contributor to the increase was higher employee compensation and benefits costs, which were largely related to growth and industry inflation experienced during most of 2008. The increase in employee compensation and benefits caused gross G&A to increase $15 million. Employee severance costs also increased, contributing to the increase in gross G&A.

Interest Expense

The following schedule includes the components of interest expense for the three-month periods ended March 31, 2009 and 2008.

	Three Months Ended March 31, 2009	2008
	(In millions)	
Interest based on debt outstanding	$ 108	$ 126
Capitalized interest	(27)	(31)
Other	2	7
Total	$ 83	$ 102

Interest based on debt outstanding decreased during the first quarter of 2009 primarily due to a decrease in outstanding borrowings. In the second quarter of 2008, we used proceeds from our West African divestiture program and cash flow from operations to repay commercial paper and credit facility borrowings. As a result, we had lower commercial paper and credit facility borrowings in 2009 than in 2008. Additionally, we retired our exchangeable debentures during the third quarter of 2008. These decreases were partially offset by 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.

Change in Fair Value of Other Financial Instruments

The details of the changes in fair value of other financial instruments for the three months ended March 31, 2009 and 2008 are shown in the table below.

	Three Months Ended March 31, 2009	2008
	(In millions)	
(Gains) losses from:		
Interest rate swaps settlements	$ (16)	$
Interest rate swaps fair value changes	11	
Chevron common stock		113
Option embedded in exchangeable debentures		(97)
Total	$ (5)	$ 16

Interest Rate Swaps

During the first quarter of 2009, we received cash settlements totaling $16 million 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 first quarter of 2009, we recorded an $11 million unrealized fair value loss as a result of changes in interest rates subsequent to December 31, 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 March 31, 2009, a 10% increase in these forward curves would have increased our first quarter 2009 unrealized loss for our interest rate swaps by approximately $6 million.

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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 five separate counterparties and have cash collateral posting requirements. Additionally, the credit ratings of all our counterparties were investment grade as of March 31, 2009.

Chevron Common Stock and Related Embedded Option

The 2008 loss on our investment in Chevron common stock and gain on the embedded option were directly attributable to a $7.97 per share decrease of Chevron s common stock during the first quarter of 2008. The Chevron common stock was exchanged for Chevron s interest in certain oil and gas properties and cash in the fourth quarter of 2008. The exchangeable debentures were retired in August 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		
	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.

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Income Taxes

The following table presents our total income tax expense 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 periods ended March 31, 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 March 31,	
	2009	**2008**
Total income tax (benefit) expense (In millions)	$ (2,269)	$ 241
U.S. statutory income tax rate	(35%)	35%
Canadian statutory rate reductions		(1%)
Other, primarily taxation on foreign operations	(1%)	(7%)
Effective income tax rate	(36%)	27%

In the first quarter of 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, our effective tax rate was 19%. This rate and the 2008 rate 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. Additionally, in the first quarter of 2008 deferred taxes were reduced by $7 million due to statutory rate reductions enacted by the British Columbia and Saskatchewan provincial governments in Canada.

Capital Resources, Uses and Liquidity

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

Sources and Uses of Cash

	Three Months Ended March 31,	
	2009	**2008**
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 1,042	$ 2,070
Commercial paper borrowings	894	
Proceeds from debt issuance, net of commercial paper repayments	182	
Sales of property and equipment	1	105
Stock option exercises	4	74
Net sales of long-term and short-term investments	2	220
Other	2	27
Total sources of cash and cash equivalents	**2,127**	**2,496**
Uses of cash and cash equivalents:		
Capital expenditures	(2,019)	(1,862)
Repayments of debt	(1)	(129)
Repurchases of common stock		(64)
Dividends	(70)	(73)

Total uses of cash and cash equivalents		**(2,090)**		**(2,128)**
Increase from continuing operations		37		368
(Decrease) increase from discontinued operations		(9)		161
Effect of foreign exchange rates		(11)		(19)
Net increase in cash and cash equivalents	**$**	**17**	**$**	**510**
Cash and cash equivalents at end of period	**$**	**401**	**$**	**1,883**

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Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) continued to be a significant source of capital and liquidity in the first three months of 2009. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to noncash expenses such as DD&A, property impairments, financial instrument fair value changes and deferred income taxes. Our operating cash flow decreased in 2009 primarily due to the decrease in revenues as discussed in the Results of Operations section of this report.

During the first three months of 2009, our operating cash flow funded approximately half of our cash payments for capital expenditures. Commercial paper borrowings were used to fund the remainder of our cash-based capital expenditures. During the first three months of 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 $1.0 billion of outstanding commercial paper as of December 31, 2008.

Subsequent to the $1.0 billion commercial paper repayment in January 2009, we utilized additional commercial paper borrowings of $894 million to fund capital expenditure payments in excess of first quarter operating cash flow.

Capital Expenditures

Following are the components of our capital expenditures for the first quarters 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 quarters of 2009 and 2008 were approximately $1.5 billion and $2.0 billion, respectively.

	Three Months Ended March 31,	
	2009	**2008**
	(In millions)	
U.S. Onshore	$ 1,107	$ 959
U.S. Offshore	333	244
Canada	327	415
International	90	110
Total exploration and development	1,857	1,728
Midstream	128	104
Other	34	30
Total cash paid for capital expenditures	$ 2,019	$ 1,862

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 $1.9 billion and $1.7 billion in the first quarters 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. As we scale back our drilling activities in response to the decline in our operating cash flow, capital expenditures for exploration, development and midstream activities are expected to be lower in each of the remaining 2009 quarters compared to the first quarter.

Our exploration and development capital expenditures increased $129 million in the first quarter of 2009. The higher expenditures primarily related to an increase in cash payments associated with drilling activities in the Barnett Shale and Gulf of Mexico.

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Repayments of Debt

During the first quarter of 2008, we reduced our credit facility and commercial paper borrowings by $88 million. Also during the first quarter of 2008, certain holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock prior to the debentures August 15, 2008 maturity date. In lieu of delivering shares of Chevron common stock we owned, we exercised our option to pay exchanging debenture holders cash equal to the market value of Chevron common stock. We paid $41 million in cash to debenture holders who exercised their exchange rights in the first quarter of 2008. This amount included the retirement of debentures with a book value of $25 million and a $16 million reduction of the related embedded derivative option s balance.

Repurchases of Common Stock

During the first quarter of 2008, we repurchased 0.8 million shares at a cost of $64 million.

Dividends

Our common stock dividends were $70 million and $71 million (quarterly rates of $0.16 per share) in the first quarter of 2009 and 2008, respectively. Our preferred dividends were $2 million in the first quarter of 2008. The decrease in the preferred dividends was due to the redemption of our preferred stock in the second quarter of 2008.

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 54% to $1.0 billion in the first quarter of 2009 compared to the first quarter of 2008. In spite of this decline, we expect operating cash flow will continue to be a primary source of liquidity. However, based on current commodity prices and near-term price expectations, we also expect that debt borrowings will be a significant source of liquidity during 2009. During the first quarter of 2009, our net borrowings of long-term debt and commercial paper totaled $1.1 billion. We anticipate we will borrow additional commercial paper during 2009 to assist in funding our capital expenditures and other capital uses.

Credit Lines

As of April 30, 2009, we had $2.2 billion of available capacity under our credit facilities that can be used to supplement our operating cash flow and cash on hand to fund our capital expenditures and other commitments. The following schedule summarizes the capacity of our credit facilities by maturity date, as well as our available capacity as of April 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 3, 2009 maturity	700
Total credit facility capacity	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	997
Outstanding letters of credit	111

Total available capacity	$	2,242

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 March 31, 2009, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at March 31, 2009, as calculated pursuant to the terms of the agreement, was 21.3%.

Capital Expenditures

In February 2009, we provided guidance for our 2009 capital expenditures. At that time, we estimated total capital expenditures would range from $4.7 billion to $5.4 billion. This estimate is significantly lower than our 2008 capital expenditures, which 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 FASB issued Staff Position No. FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets. Staff Position 132(R)-1 amends FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits, to require additional disclosures about the types of assets and associated risks in an employer s defined benefit pension or other postretirement plan. Staff Position 132(R)-1 is effective for fiscal years ending after December 15, 2009. We are evaluating the impact the adoption of Staff Position 132(R)-1 will have on our financial statement disclosures. However, our adoption of Staff Position 132(R)-1 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. The 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 alternative 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.

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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 approximately 10% of our 2009 gas production. The key terms to these 2009 price collars are included in Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2008 Annual Report on Form 10-K.

The fair values of our gas price collar hedging instruments are largely determined by estimates of the forward curves of the Inside FERC Henry Hub index. At March 31, 2009, a 10% increase in the Inside FERC Henry Hub index forward curves would have decreased the net assets recorded for our gas price collar hedging instruments by approximately $29 million.

Interest Rate Risk

At March 31, 2009, we had debt outstanding of $6.9 billion. Of this amount, $6.0 billion, or 87%, bears interest at fixed rates averaging 7.2%. Additionally, we had $0.9 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.7%.

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 $200 million and expire on September 30, 2011. The terms of these contracts specify that the swaps will be net settled in September 2011. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.55% and receiving a floating rate that is based upon the three-month LIBOR forward curve. The difference between these fixed and floating rates will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041.

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds Rate and LIBOR. At March 31, 2009, a 10% increase in these forward curves would have increased our net assets recorded for our interest rate derivative instruments by approximately $6 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 March 31, 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.

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Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the first quarter of 2009 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

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Part II. Other Information

Item 1. ***Legal Proceedings***

There have been no material changes to the information included in Item 3. Legal Proceedings in our 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 quarter of 2009.

As of March 31, 2009, we are authorized to repurchase 50.3 million shares. This amount is comprised of 45.5 million remaining shares authorized to be repurchased under a 50 million share repurchase program and 4.8 million shares authorized to be repurchased in 2009 under an annual 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***

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

Exhibit Number	Description
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.

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SIGNATURES

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

DEVON ENERGY CORPORATION

Date: May 7, 2009

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

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INDEX TO EXHIBITS

Exhibit Number	Description
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.