DEVON ENERGY CORP/DE
Form 10-Q
November 07, 2007

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

(Mark One)

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

For the Quarterly Period Ended September 30, 2007

or

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

Commission File No. 001-32318
Devon Energy Corporation
(Exact Name of Registrant as Specified in its Charter)

Delaware	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification Number)*
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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

The number of shares outstanding of Registrant s common stock, par value $0.10, as of October 31, 2007, was 444,960,000.

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q 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 which was used to prepare the December 31, 2006 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 the negatives or variat or similar terminology. Although we believe that the 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;
- production levels, including our Canadian production subject to government royalties which fluctuate with prices and our International production governed by payout agreements which affect reported production;
- reserve levels;
- competitive conditions;
- technology;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- the supply and demand for oil, natural gas, NGLs and other energy products or services;
- the price of oil, natural gas, NGLs and other energy products or services;
- currency exchange rates;
- the weather;
- inflation;
- the availability of goods and services;
- drilling risks;
- future processing volumes and pipeline throughput;
- general economic conditions, either internationally or 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 or the timing of such planned transactions;

the securities or capital markets; and

other factors disclosed in Devon s 2006 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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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.

MMBbls means million barrels.

MMBoe means million Boe.

Mcf means thousand cubic feet.

NGL or NGLs means natural gas liquids.

Oil includes crude oil and condensate.

SEC means United States Securities and Exchange Commission.

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

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

United States Offshore means the properties of Devon in the Gulf of Mexico.

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

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

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PART I. Financial Information

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	September 30, 2007 (Unaudited)	December 31, 2006
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,392	692
Short-term investments, at fair value	341	574
Accounts receivable	1,435	1,324
Current assets held for sale	176	232
Other current assets	340	390
Total current assets	3,684	3,212
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,371 and $3,293 excluded from amortization in 2007 and 2006, respectively)	46,546	39,585
Less accumulated depreciation, depletion and amortization	19,561	16,429
	26,985	23,156
Investment in Chevron Corporation common stock, at fair value	1,327	1,043
Goodwill	6,150	5,706
Assets held for sale	1,707	1,619
Other assets	418	327
Total assets	$ 40,271	35,063
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,268	1,154
Revenues and royalties due to others	529	522
Income taxes payable	187	82
Short-term debt	2,076	2,205
Accrued interest payable	191	114
Current liabilities associated with assets held for sale	190	173
Accrued expenses and other current liabilities	325	395
Total current liabilities	4,766	4,645
Debentures exchangeable into shares of Chevron Corporation common stock	638	727
Other long-term debt	5,235	4,841

Financial instruments, at fair value	495	302
Asset retirement obligation, at fair value	1,246	804
Liabilities associated with assets held for sale	445	429
Other liabilities	622	583
Deferred income taxes	5,992	5,290
Stockholders equity:		
Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value)	1	1
Common stock of $0.10 par value. Authorized 800,000,000 shares; issued 444,699,000 in 2007 and 444,040,000 in 2006	45	44
Additional paid-in capital	6,883	6,840
Retained earnings	11,564	9,114
Accumulated other comprehensive income	2,339	1,444
Treasury stock, at cost: 11,000 shares in 2006		(1)
Total stockholders equity	20,832	17,442
Commitments and contingencies (Note 6)		
Total liabilities and stockholders equity	$ 40,271	35,063

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues:				
Oil sales	$ 905	696	2,461	1,806
Gas sales	1,182	1,186	3,788	3,709
NGL sales	242	204	643	573
Marketing and midstream revenues	434	413	1,273	1,261
Total revenues	2,763	2,499	8,165	7,349
Expenses and other income, net:				
Lease operating expenses	457	363	1,326	1,036
Production taxes	85	92	255	261
Marketing and midstream operating costs and expenses	301	301	912	924
Depreciation, depletion and amortization of oil and gas properties	705	547	1,937	1,480
Depreciation and amortization of non-oil and gas properties	51	43	146	127
Accretion of asset retirement obligation	19	12	55	35
General and administrative expenses	126	104	358	284
Interest expense	108	112	325	315
Change in fair value of financial instruments	(22)	22	(31)	81
Reduction of carrying value of oil and gas properties		20		36
Other income, net	(28)	(28)	(71)	(86)
Total expenses and other income, net	1,802	1,588	5,212	4,493
Earnings from continuing operations before income tax expense	961	911	2,953	2,856
Income tax expense:				
Current	96	147	459	471
Deferred	221	111	452	253
Total income tax expense	317	258	911	724
Earnings from continuing operations	644	653	2,042	2,132
Discontinued operations:				
Earnings from discontinued operations before income tax expense	177	112	442	337
Income tax expense	86	60	194	205
Earnings from discontinued operations	91	52	248	132
Net earnings	735	705	2,290	2,264

Preferred stock dividends	2	2	7	7
Net earnings applicable to common stockholders	$ 733	703	2,283	2,257
Basic net earnings per share:				
Earnings from continuing operations	$ 1.45	1.47	4.57	4.81
Earnings from discontinued operations	0.20	0.12	0.56	0.30
Net earnings	$ 1.65	1.59	5.13	5.11
Diluted net earnings per share:				
Earnings from continuing operations	$ 1.43	1.45	4.52	4.76
Earnings from discontinued operations	0.20	0.12	0.55	0.29
Net earnings	$ 1.63	1.57	5.07	5.05
Weighted average common shares outstanding:				
Basic	445	441	445	441
Diluted	450	447	450	447

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Unaudited) (In millions)			
Net earnings	$ 735	705	2,290	2,264
Foreign currency translation:				
Change in cumulative translation adjustment	579	(1)	1,311	303
Income taxes	(33)		(74)	7
Total	546	(1)	1,237	310
Derivative financial instruments reclassification adjustment for realized gains included in net earnings			(1)	(1)
Pension and postretirement benefit plans:				
Recognition of net actuarial loss in net earnings	4		12	
Income taxes	(2)		(5)	
Total	2		7	
Investment in Chevron Corporation common stock (Note 1):				
Unrealized holding gain		39		114
Income taxes		(14)		(41)
Total		25		73
Other comprehensive income, net of tax	548	24	1,243	382
Comprehensive income	$ 1,283	729	3,533	2,646

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)			
Nine Months Ended September 30, 2007								
Balance as of December 31, 2006	$ 1	444	$ 44	6,840	9,114	1,444	(1)	17,442
Adoption of FASB Statement No. 159 (Note 1)					364	(364)		
Adoption of FASB Interpretation No. 48 (Note 1)					(10)			(10)
Adoption of FASB Statement No. 158 (Note 4)					(1)	16		15
Net earnings					2,290			2,290
Other comprehensive income						1,243		1,243
Stock option exercises		3	1	70				71
Common stock repurchased		(2)					(138)	(138)
Common stock retired				(139)			139	
Common stock dividends					(186)			(186)
Preferred stock dividends					(7)			(7)
Share-based compensation				92				92
Excess tax benefits on share-based compensation				20				20
Balance as of September 30, 2007	$ 1	445	$ 45	6,883	11,564	2,339		20,832
Nine Months Ended September 30, 2006								
Balance as of December 31, 2005	$ 1	443	$ 44	6,928	6,477	1,414	(2)	14,862
Net earnings					2,264			2,264
Other comprehensive income						382		382
Stock option exercises		2		53				53
Restricted stock grants, net of cancellations		1		(3)			(2)	(5)
Common stock repurchased		(4)					(253)	(253)
Common stock retired				(256)			256	

Common stock dividends				(148)			(148)
Preferred stock dividends				(7)			(7)
Share-based compensation			55				55
Excess tax benefits on share-based compensation			14				14
Balance as of September 30, 2006	$ 1	$ 442	44	6,791	8,586	1,796	(1) 17,217

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2007	2006
	(Unaudited) (In Millions)	
Cash flows from operating activities:		
Net earnings	$ 2,290	2,264
Earnings from discontinued operations, net of tax	(248)	(132)
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	2,083	1,607
Deferred income tax expense	452	253
Net gain on sales of non-oil and gas property and equipment	(1)	(5)
Reduction of carrying value of oil and gas properties		36
Other noncash charges	125	163
Changes in assets and liabilities:		
(Increase) decrease in:		
Accounts receivable	(12)	206
Other current assets	(65)	(45)
Long-term other assets	(53)	(37)
Increase (decrease) in:		
Accounts payable	111	(59)
Income taxes payable	139	(34)
Other current liabilities	(78)	197
Long-term other liabilities	(4)	(1)
Cash provided by operating activities continuing operations	4,739	4,413
Cash provided by operating activities discontinued operations	370	469
Net cash provided by operating activities	5,109	4,882
Cash flows from investing activities:		
Proceeds from sales of property and equipment	39	36
Capital expenditures, including acquisitions of businesses	(4,477)	(5,959)
Purchases of short-term investments	(659)	(1,868)
Sales of short-term investments	892	2,424
Cash used in investing activities continuing operations	(4,205)	(5,367)
Cash used in investing activities discontinued operations	(153)	(187)
Net cash used in investing activities	(4,358)	(5,554)
Cash flows from financing activities:		
Net senior credit facility borrowings, net of issuance costs	400	

Net commercial paper (repayments) borrowings, net of issuance costs	(129)	1,439
Principal payments on debt, including current maturities	(166)	(860)
Proceeds from exercise of stock options	71	53
Repurchases of common stock	(133)	(253)
Excess tax benefits related to share-based compensation	20	14
Dividends paid on common stock	(186)	(148)
Dividends paid on preferred stock	(7)	(7)
Net cash (used in) provided by financing activities	(130)	238
Effect of exchange rate changes on cash	44	24
Net increase (decrease) in cash and cash equivalents	665	(410)
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	756	1,606
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 1,421	1,196
Supplementary cash flow data:		
Interest paid (net of capitalized interest)	$ 226	349
Income taxes paid	$ 293	581

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 consolidated financial statements and notes thereto of Devon Energy Corporation (Devon) have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission. Accordingly, 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 thereto should be read in conjunction with the consolidated financial statements and notes thereto included in Devon s 2006 Annual Report on Form 10-K.

In the opinion of Devon s management, all adjustments (all of which are normal and recurring) that have been made are necessary to fairly state the consolidated financial position of Devon and its subsidiaries as of September 30, 2007, and the results of their operations and their cash flows for the three-month and nine-month periods ended September 30, 2007 and 2006.

Net Earnings Per Common Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share for the three-month and nine-month periods ended September 30, 2007 and 2006.

	Net Earnings Applicable to Common Stockholders	Weighted Average Common Shares Outstanding	Net Earnings per Share
	(In millions, except per share amounts)		
Three Months Ended September 30, 2007:			
Earnings from continuing operations	$ 644		
Less preferred stock dividends	(2)		
Basic earnings per share	642	445	$ 1.45
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		5	
Diluted earnings per share	$ 642	450	$ 1.43
Three Months Ended September 30, 2006:			
Earnings from continuing operations	$ 653		
Less preferred stock dividends	(2)		
Basic earnings per share	651	441	$ 1.47
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		6	
Diluted earnings per share	$ 651	447	$ 1.45

Nine Months Ended September 30, 2007:			
Earnings from continuing operations	$ 2,042		
Less preferred stock dividends	(7)		
Basic earnings per share	2,035	445	$ 4.57
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		5	
Diluted earnings per share	$ 2,035	450	$ 4.52
Nine Months Ended September 30, 2006:			
Earnings from continuing operations	$ 2,132		
Less preferred stock dividends	(7)		
Basic earnings per share	2,125	441	$ 4.81
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		6	
Diluted earnings per share	$ 2,125	447	$ 4.76

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

Certain options to purchase shares of Devon s common stock are excluded from the dilution calculations because the options are antidilutive. During the three-month and nine-month periods ended September 30, 2007, 2.1 million and 4.0 million shares were excluded from the diluted earnings per share calculations, respectively. During both the three-month and nine-month periods ended September 30, 2006, 2.6 million shares were excluded from the diluted earnings per share calculations.

Short-term Investments and Other Marketable Securities Change in Accounting Principle

Devon owns approximately 14.2 million shares of Chevron Corporation (Chevron) common stock. The majority of these shares are held in connection with debt owed by Devon that contains an exchange option. This exchange option allows the debt holders, prior to the debt s maturity, to exchange the debt for the shares of Chevron common stock owned by Devon.

The shares of Chevron common stock and the exchange option embedded in the debt have always been recorded on Devon s balance sheet at fair value. However, pursuant to accounting rules prior to January 1, 2007, only the change in fair value of the embedded option has historically been included in Devon s results of operations. Conversely, the change in fair value of the Chevron common stock has not been included in Devon s results of operations, but instead has been recorded directly to stockholders equity as part of accumulated other comprehensive income.

Effective January 1, 2007, Devon adopted Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*. Statement No. 159 allows a company the option to value its financial assets and liabilities, on an instrument by instrument basis, at fair value, and include the change in fair value of such assets and liabilities in its results of operations. Devon chose to apply the provisions of Statement No. 159 to its shares of Chevron common stock. Accordingly, beginning with the first quarter of 2007, the change in fair value of the Chevron common stock owned by Devon, along with the change in fair value of the related exchange option, are both included in Devon s results of operations.

In the three-month and nine-month periods ended September 30, 2007, the change in fair value of financial instruments caption on Devon s statements of operations includes unrealized gains of $133 million and $285 million, respectively, related to the Chevron common stock, and unrealized losses of $111 million and $255 million, respectively, related to the embedded option. In the three-month and nine-month periods ended September 30, 2006, prior to adopting Statement No. 159, unrealized losses of $22 million and $83 million, respectively, related to the change in fair value of the embedded option were included in the change in fair value of financial instruments caption on Devon s statements of operations.

As of December 31, 2006, $364 million of after-tax unrealized gains related to Devon s investment in the Chevron common stock was included in accumulated other comprehensive income. This is the amount of unrealized gains that, prior to Devon s adoption of Statement No. 159, had not been recorded in Devon s historical results of operations. Upon the adoption of Statement No. 159 as of January 1, 2007, this $364 million of unrealized gains was reclassified on Devon s balance sheet from accumulated other comprehensive income to retained earnings.

In conjunction with the adoption of Statement No. 159, Devon also adopted on January 1, 2007 Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*. Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements, but does not require any new fair value measurements. The adoption of Statement No. 157 had no impact on Devon s financial statements, but it did result in additional required disclosures as set forth in Note 7.

Income Taxes Change in Accounting Principle

Devon and its subsidiaries are subject to current income taxes assessed by the federal and various state jurisdictions in the United States and by other foreign jurisdictions. In addition, Devon accounts for deferred income taxes related to these jurisdictions using the asset and

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

liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

At September 30, 2007, undistributed earnings of foreign subsidiaries included in continuing operations were determined to be permanently reinvested. Therefore, no U.S. deferred income taxes were provided on such amounts at September 30, 2007. If it becomes apparent that some or all of the undistributed earnings will be distributed, Devon would then record taxes on those earnings.

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* Interpretation No. 48 prescribes a threshold for recognizing the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits related to such tax positions are included in other long-term liabilities unless the tax position is expected to be settled within the upcoming year, in which case the liabilities are included in accrued expenses and other current liabilities. Interest and penalties related to unrecognized tax benefits are included in income tax expense.

On January 1, 2007, Devon adopted Interpretation No. 48 and recorded a $10 million reduction to the January 1, 2007 balance of retained earnings related to unrecognized tax benefits. The $10 million includes $8 million for related interest and penalties. An additional $2 million of liabilities were recorded with a corresponding increase to goodwill.

As a result of the adoption of Interpretation No. 48, certain liabilities included in income taxes payable and deferred income taxes were reclassified to other current and long-term liabilities in the accompanying balance sheet. The total $12 million increase in liabilities included a $15 million increase to long-term liabilities, partially offset by a $3 million reduction to current liabilities.

As of January 1, 2007, Devon s unrecognized tax benefits were $114 million. This amount included $82 million that, if recognized, would affect Devon s effective income tax rate.

Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. federal	2002-2006
Various U.S. states	2001-2006
Canada federal	2000-2006
Various Canadian provinces	2000-2006
Various other foreign jurisdictions	1997-2006

Devon is currently in the final stages of the administrative review process for certain open tax years. In addition, certain statute of limitation expirations are scheduled to occur in the next twelve months. Due to these factors, Devon anticipates it is reasonably possible that liabilities for certain tax positions will decrease between $15 million and $25 million within the next twelve months.

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

2. Property and Equipment and Asset Retirement Obligations (ARO)

Divestitures

On November 14, 2006, Devon announced that it intended to divest its operations in Egypt. Devon closed the sale of its Egyptian properties on October 4, 2007. Also, on January 23, 2007, Devon announced that it intends to divest its operations in West Africa. See Note 11 for more discussion regarding these divestiture activities.

Asset Retirement Obligations

The following is a summary of the changes in Devon s ARO for the first nine months of 2007 and 2006.

	Nine Months Ended September 30,	
	2007	2006
	(In millions)	
Asset retirement obligation as of beginning of period	$ 857	636
Liabilities incurred	44	92
Liabilities settled	(52)	(39)
Revision of estimated obligation	311	135
Accretion expense on discounted obligation	55	35
Foreign currency translation adjustment	85	13
Asset retirement obligation as of end of period	1,300	872
Less current portion	54	45
Asset retirement obligation, long-term	$ 1,246	827

During the nine months ended September 30, 2007 and 2006, Devon recognized a $311 million and $135 million revision to its ARO, respectively. The primary factors causing the 2007 fair value increase were an overall increase in abandonment cost estimates and an increase in the assumed inflation rate. The effect of these factors was partially offset by the effect of an increase in the discount rate used to calculate the present value of the obligations. The primary factor causing the 2006 fair value increase was an overall increase in abandonment cost estimates.

3. Debt

Senior Credit Facility

In April 2007, Devon extended the maturity of its existing $2.5 billion five-year, syndicated, unsecured revolving line of credit (the Senior Credit Facility) from April 7, 2011 to April 7, 2012.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. As of September 30, 2007, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at September 30, 2007, as calculated pursuant to the terms of the agreement, was 24.8%.

As of September 30, 2007, Devon had $400 million of outstanding borrowings under the Senior Credit Facility at an average rate of 5.85%. The available capacity under the Senior Credit Facility as of September 30, 2007, net of these borrowings as well as $1.7 billion of outstanding commercial paper and $280 million of outstanding letters of credit, was approximately $128 million.

Short-Term Credit Facility

On August 7, 2007, Devon established a new $1.5 billion 364-day, syndicated, unsecured revolving senior credit facility (the Short-Term Facility). This new facility provides Devon with provisional interim liquidity until it receives the proceeds from divestitures of assets in Africa (see Note 11). The Short-Term Facility was also used to support an increase in Devon s commercial paper program from $2 billion to $3.5 billion.

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The Short-Term Facility matures 364 days from the closing date. On the maturity date, all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to the maturity date, Devon has the option to convert any outstanding principal amount of loans under the Short-Term Facility to a term loan which will be repayable in a single payment 364 days from the maturity date.

Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Short-Term Facility currently provides for an annual facility fee of approximately $1.0 million that is payable quarterly in arrears.

The agreement governing the Short-Term Facility contains substantially the same covenants and restrictions as Devon s existing Senior Credit Facility, including a maximum allowed debt-to-capitalization ratio of 65% as defined in the agreement.

As of September 30, 2007, there were no amounts borrowed under the Short-Term Facility, and the available capacity was $1.5 billion.

Commercial Paper

As of September 30, 2007, Devon had $1.7 billion of outstanding commercial paper at an average rate of 5.66%.

Exchangeable Debentures

During the third quarter of 2007, certain holders of exchangeable debentures exercised their option to convert their debentures prior to the August 15, 2008 maturity date. Devon has the option to settle conversions of the exchangeable debentures with either shares of Chevron common stock or cash equal to the market value of Chevron common stock at the time of conversion. Devon paid $166 million in cash to settle the conversions in the third quarter of 2007. As a result of the $166 million payment, Devon retired outstanding exchangeable debentures totaling $104 million as well as the related embedded derivative option with a value of $62 million.

As of September 30, 2007, the Chevron exchangeable debentures are due within one year. However, Devon continues to classify this debt as long-term because it has the intent and ability to refinance these debentures on a long-term basis with the available capacity under its existing credit facilities or other long-term financing arrangements.

4. Retirement Plans

Net Periodic Benefit Cost and Other Comprehensive Income

The following table presents the components of net periodic benefit cost and other comprehensive income for Devon s pension and other post retirement benefit plans for the three-month and nine-month periods ended September 30, 2007 and 2006.

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	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006	2007	2006	2007	2006
	(In millions)							
Net periodic benefit cost:								
Service cost	$ 8	6	23	18				
Interest cost	11	10	33	30	1	1	3	3
Expected return on plan assets	(12)	(11)	(36)	(33)				
Net actuarial loss	3	3	10	9				
Net periodic benefit cost	10	8	30	24	1	1	3	3
Other comprehensive income:								
Recognition of net actuarial loss in net periodic benefit cost	(4)		(12)					
Total recognized	$ 6	8	18	24	1	1	3	3

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. Statement No. 158 requires the measurement of plan assets and benefit obligations as of the date of the employer s fiscal year-end, beginning with fiscal years ending after December 15, 2008. Although not required until 2008, Devon adopted this measurement-date requirement in the second quarter of 2007 and is changing its measurement date from November 30 to December 31. As a result, Devon used data as of December 31, 2006 to remeasure its plans assets and benefit obligations previously measured using data as of November 30, 2006. As a result of the remeasurement, Devon recognized the following amounts in the second quarter of 2007.

	Increase (Decrease) (In millions)
Other long-term liabilities	(26)
Deferred income tax liabilities	9
Retained earnings	(1)
Accumulated other comprehensive income	16
General and administrative expenses	2

Revisions to Retirement Plans

Devon has various noncontributory defined benefit pension plans, including qualified and nonqualified plans (Defined Benefit Plans), that provide defined levels of benefits to its domestic employees. Devon also has a 401(k) Incentive Savings Plan (401(k) Plan) that covers its domestic employees. Benefits under the 401(k) Plan consist of a discretionary match of a percentage of employees contributions to the 401(k) Plan.

In the second quarter of 2007, Devon adopted an enhanced defined contribution structure related to the 401(k) Plan to be effective January 1, 2008. Participants in this enhanced defined contribution structure will continue to receive a

discretionary match of a percentage of their contributions to the 401(k) Plan. These participants will also receive additional, nondiscretionary contributions by Devon calculated as a percentage of annual compensation. The percentage will vary based on the employee s years of service.

On or before November 15, 2007, existing eligible employees will elect to either continue to participate in the Defined Benefit Plan or participate in the enhanced defined contribution structure of the 401(k) Plan. Employees who continue to participate in the Defined Benefit Plans will continue to accrue benefits under the existing provisions of the Defined Benefit Plans. Employees who elect to participate in the enhanced defined contribution structure will receive enhanced contributions to the 401(k) Plan and will retain the benefits which they have accrued under the Defined Benefit Plan as of December 31, 2007. However, such employees will only be entitled to the

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benefits which have accrued in the Defined Benefit Plans as of December 31, 2007, after all applicable vesting requirements have been met. Employees hired on or after October 1, 2007 will not have an election and will only participate in the 401(k) Plan and the enhanced defined contribution structure.

The effect the employee elections will have on Devon s benefit obligations and related expenses will not be known until such elections are made with respect to the Defined Benefit Plans. However, based upon the most likely employee election scenarios, Devon expects that the effect, including any accelerated recognition of obligations of the Defined Benefit Plans, will be immaterial to its financial statements.

5. Stockholders Equity

Stock Repurchases

In August 2005, Devon s Board of Directors approved a stock repurchase program to repurchase up to 50 million shares of Devon s common stock. This program was suspended in 2006 as a result of the $2.0 billion acquisition of oil and gas properties from Chief Holdings LLC (Chief) in June 2006. Prior to the suspension of the program and as of September 30, 2007, Devon had repurchased 6.5 million shares under this program for $387 million, or $59.80 per share. Although this program expires at the end of 2007, it could be extended. Should the Board of Directors elect to extend this repurchase program beyond the end of 2007, management expects to resume repurchases in conjunction with the closings of the planned sales of Devon s operations in West Africa (see Note 11).

On June 6, 2007, Devon s Board of Directors approved an ongoing, annual stock repurchase program to offset dilution resulting from restricted stock issued to, and options exercised by, employees. The new repurchase program authorizes the repurchase of up to 4.5 million shares in 2007 and is in addition to the repurchase program described above. As of September 30, 2007, Devon had repurchased 1.8 million shares under the new program for $136 million, or $77.49 per share.

Dividends

Dividends on Devon s common stock were paid in 2007 and 2006 at quarterly per share rates of $0.14 and $0.1125, respectively.

6. Commitments and Contingencies

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

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act (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.

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Certain of Devon s subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties (PRPs) under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of September 30, 2007, Devon s consolidated balance sheet included $4 million of non-current accrued liabilities, reflected in Other 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 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 natural gas liquids 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 the 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. A defendant other than Devon is set for trial in August 2008. The next phase trial is set for February 2009. Defendants, other than Devon, were selected for this trial. 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 in association with this lawsuit and no liability has been recorded in connection therewith.

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 natural 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. The MMS in 2006 informed Devon and other oil and gas companies that the omission of price thresholds from these leases was an error on its part and was not its intention. Accordingly, the MMS invited Devon and the other affected oil and gas producers to renegotiate the terms and conditions of the 1998 and 1999 leases to add price threshold provisions to the lease agreements for periods after October 1, 2006. Devon has since had several discussions with MMS representatives on this issue, but has not yet entered into renegotiated leases.

The U.S. House of Representatives in January 2007 and July 2007 passed legislation that would require companies to renegotiate the 1998 and 1999 leases as a condition of securing future federal leases. If this legislation were to become law, it would require price thresholds to be effective in the renegotiated 1998 and 1999 leases effective October 1, 2006. Although Devon has not yet signed renegotiated leases, it has accrued through September 30, 2007 approximately $21 million for royalties that would be due if price thresholds were added to its 1998 and 1999 leases effective October 1, 2006.

Canadian Royalties

On October 25, 2007, the Alberta government proposed increases to the royalty rates on oil and natural gas production beginning in 2009. Devon believes this proposal would reduce future earnings and cash flows from its oil and gas properties located in Alberta. Additionally, assuming all other factors are equal, higher royalty rates would

likely result in lower levels of capital investment in Alberta relative to Devon s other areas of operation.

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However, the magnitude of the potential impact, which will depend on the final form of enacted legislation and other factors which impact the relative expected economic returns of capital projects, cannot be reasonably estimated at this time.

Equatorial Guinea Investigation

The SEC has been conducting an inquiry into payments made to the government of Equatorial Guinea and to officials and persons affiliated with officials of the government of Equatorial Guinea. On August 9, 2005, Devon received a subpoena issued by the SEC pursuant to a formal order of investigation. Devon has cooperated fully with the SEC s requests for information in this inquiry. After responding in 2005 to such requests for information, Devon has not been contacted by the SEC. In the event that Devon receives any further inquiries, Devon will work with the SEC in connection with its investigation.

Hurricane Contingencies

Historically, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. Devon s historical insurance program also included substantial business interruption coverage which Devon is utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of this insurance program, Devon was entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Based on current estimates of physical damage and the anticipated length of time Devon will have production suspended, Devon expects its policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in the third quarter of 2006 as a full settlement of the amount due from Devon s primary insurers and $13 million received in the second quarter of 2007 as a full settlement of the amount due from certain of Devon s secondary insurers. Devon continues to negotiate with its other secondary insurers and expects to receive additional policy recoveries as a result of such negotiations. As of September 30, 2007, $281 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $199 million are expected to be utilized as reimbursement of Devon s anticipated future repair costs.

Should Devon s total policy recoveries, including settlements already received from Devon s primary and secondary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made.

The policy underlying the insurance program terms described above expired on August 31, 2006. During the third quarter of 2006 and again in the third quarter of 2007, Devon was able to re-establish a comprehensive insurance program that includes business interruption and physical damage coverage for its business. However, due to significant changes in the marketplace, Devon was only able to obtain a *de minimis* amount of coverage for any damage that may be caused by named windstorms in the Gulf of Mexico. Devon has not experienced any windstorm losses covered by the new insurance arrangements through September 30, 2007.

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7. Fair Value Measurements

Certain of Devon s assets and liabilities are reported at fair value in the accompanying balance sheets. The following table provides fair value measurement information for such assets and liabilities as of September 30, 2007.

		Fair Value Measurements Using:		
	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In millions)		
Assets:				
Short-term investments	$ 341	341		
Investment in Chevron common stock	$1,327	1,327		
Financial instruments	$ 8		8	
Liabilities:				
Financial instruments	$ 497		497	
Asset retirement obligation (ARO)	$1,300			1,300

Statement No. 157 (see Note 1) establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table above, this hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 3 inputs have the lowest priority.

Devon uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value. Devon owes debt that has an embedded exchange option. Because the exchange option is not actively traded in an established market, its fair value is measured using Level 2 inputs. Devon also has certain commodity and interest-rate derivative financial instruments which are measured using Level 2 inputs, such as forward commodity price curves or interest-rate yield curves. Devon only uses Level 3 inputs to measure the fair value of its ARO. A reconciliation of the beginning and ending balances of Devon s ARO, including a revision of the fair value in 2007, is presented in Note 2.

8. Change in Fair Value of Financial Instruments

The components of change in fair value of financial instruments include the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
		(In millions)		
Option embedded in exchangeable debentures	$ 111	22	255	83
Investment in Chevron common stock (Note 1)	(133)		(285)	
Interest rate swaps			(1)	(2)
Total	$ (22)	22	(31)	81

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9. Reduction of Carrying Value of Oil and Gas Properties

The following schedule summarizes the reductions of carrying value of oil and gas properties for the third quarter and first nine months of 2006.

	Three Months Ended September 30, 2006		Nine Months Ended September 30, 2006	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
Brazil	$		16	16
Russia	20	10	20	10
Total	$ 20	10	36	26

As a result of a decline in projected future net cash flows, the carrying value of Devon s Russian properties exceeded the ceiling by $10 million in the third quarter of 2006. Therefore, in the third quarter of 2006, Devon recognized a $20 million reduction of the carrying value of its oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

During the second quarter of 2006, Devon drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, Devon recognized a $16 million impairment of its investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon s Polvo development project in Brazil.

See Note 11 for information related to reductions of carrying value of oil and gas properties included in discontinued operations.

10. Other Income

The components of other income include the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Interest and dividend income	$ 24	22	63	78
Net gain on sales of non-oil and gas property and equipment			1	5
Other	4	6	7	3
Total	$ 28	28	71	86

11. Discontinued Operations

Egypt and West Africa

On November 14, 2006, Devon announced its plans to divest its operations in Egypt. On January 23, 2007, Devon announced its plans to divest its operations in West Africa. Pursuant to accounting rules for discontinued operations, Devon has classified all 2007 and prior period amounts related to its operations in Egypt and West Africa as discontinued operations.

On October 4, 2007, Devon closed the sale of its Egyptian operations and received proceeds of $341 million. As a result of this sale, Devon will record an after-tax gain related to this transaction of approximately $130 million in the fourth quarter of 2007.

Devon is finalizing purchase and sales agreements and obtaining the necessary partner and government

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approvals for the properties in the West African divestiture package. Devon expects to complete these sales during the first half of 2008.

Revenues related to Devon s operations in Egypt and West Africa totaled $206 million and $223 million in the three months ended September 30, 2007 and September 30, 2006 and $596 million and $707 million in the nine months ended September 30, 2007 and September 30, 2006, respectively.

The following table presents the main classes of assets and liabilities associated with Devon s operations in Egypt and West Africa as of September 30, 2007 and December 31, 2006.

	September 30, 2007	December 31, 2006
	(In millions)	
Assets:		
Cash	$ 29	64
Accounts receivable	87	101
Other current assets	60	67
Current assets	$ 176	232
Long-term assets property and equipment, net of accumulated depreciation, depletion and amortization	$ 1,707	1,619
Liabilities:		
Accounts payable trade	$ 34	48
Income taxes payable	146	115
Current portion of asset retirement obligation	8	8
Accrued expenses and other current liabilities	2	2
Current liabilities	$ 190	173
Asset retirement obligation, long-term	$ 44	38
Deferred income taxes	385	375
Other liabilities	16	16
Long-term liabilities	$ 445	429

Reduction of Carrying Value

Based on recent drilling activities in Nigeria, Devon reduced the carrying value of its Nigerian assets held for sale in the second quarter of 2007. As a result, earnings from discontinued operations in the nine months ended 2007 include a $13 million after-tax loss ($64 million pre-tax).

As a result of unsuccessful exploratory activities in Egypt during the third quarter of 2006, the net book value of Devon s Egyptian oil and gas properties, less related deferred income taxes, exceeded the ceiling by $18 million as of September 30, 2006. Therefore, in the third quarter of 2006, Devon recognized a $13 million after-tax loss Egypt

($31 million pre-tax).

Due to unsuccessful drilling activities in Nigeria, in the first quarter of 2006, Devon recognized an $85 million impairment of its investment in Nigeria equal to the costs to drill two dry holes and a proportionate share of block-related costs. There was no income tax benefit related to this impairment.

12. Income Taxes

During the second quarter of 2007, the Canadian Federal government enacted a statutory rate reduction. As a result of this rate reduction, Devon recorded a $30 million deferred tax benefit in such quarter.

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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 September 30, 2007:				
Current assets	$ 1,693	837	1,154	3,684
Property and equipment, net of accumulated depreciation, depletion and amortization	17,237	8,652	1,096	26,985
Goodwill	3,053	3,029	68	6,150
Other assets	1,624	53	1,775	3,452
Total assets	$ 23,607	12,571	4,093	40,271
Current liabilities	$ 3,660	670	436	4,766
Long-term debt	2,898	2,975		5,873
Asset retirement obligation, long-term	605	569	72	1,246
Other liabilities	1,070	43	449	1,562
Deferred income taxes	3,734	2,195	63	5,992
Stockholders equity	11,640	6,119	3,073	20,832
Total liabilities and stockholders equity	$ 23,607	12,571	4,093	40,271

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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2007:				
Revenues:				
Oil sales	$ 359	224	322	905
Gas sales	867	312	3	1,182
NGL sales	196	46		242
Marketing and midstream revenues	421	13		434
Total revenues	1,843	595	325	2,763
Expenses and other income, net:				
Lease operating expenses	247	177	33	457
Production taxes	50	1	34	85
Marketing and midstream operating costs and expenses	296	5		301
Depreciation, depletion and amortization of oil and gas properties	457	193	55	705
Depreciation and amortization of non-oil and gas properties	45	5	1	51
Accretion of asset retirement obligation	10	8	1	19
General and administrative expenses	95	31		126
Interest expense	58	50		108
Change in fair value of financial instruments	(22)			(22)
Other income, net	(10)	(6)	(12)	(28)
Total expenses and other income, net	1,226	464	112	1,802
Earnings from continuing operations before income tax expense	617	131	213	961
Income tax expense (benefit):				
Current	(2)	40	58	96
Deferred	215	8	(2)	221
Total income tax expense	213	48	56	317
Earnings from continuing operations	404	83	157	644
Discontinued operations:				
Earnings from discontinued operations before income tax expense			177	177
Income tax expense			86	86
Earnings from discontinued operations			91	91
Net earnings	404	83	248	735
Preferred stock dividends	2			2

Net earnings applicable to common stockholders	$ 402	83	248	733
Capital expenditures, continuing operations	$ 1,182	291	114	1,587

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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2006:				
Revenues:				
Oil sales	$ 328	174	194	696
Gas sales	856	329	1	1,186
NGL sales	151	53		204
Marketing and midstream revenues	404	9		413
Total revenues	1,739	565	195	2,499
Expenses and other income, net:				
Lease operating expenses	207	141	15	363
Production taxes	58	1	33	92
Marketing and midstream operating costs and expenses	299	2		301
Depreciation, depletion and amortization of oil and gas properties	358	164	25	547
Depreciation and amortization of non-oil and gas properties	38	5		43
Accretion of asset retirement obligation	6	6		12
General and administrative expenses	80	24		104
Interest expense	56	56		112
Change in fair value of financial instruments	22			22
Reduction of carrying value of oil and gas properties			20	20
Other (income) expense, net	7		(35)	(28)
Total expenses and other income, net	1,131	399	58	1,588
Earnings from continuing operations before income tax expense	608	166	137	911
Income tax expense (benefit):				
Current	86	23	38	147
Deferred	93	32	(14)	111
Total income tax expense	179	55	24	258
Earnings from continuing operations	429	111	113	653
Discontinued operations:				
Earnings from discontinued operations before income tax expense			112	112
Income tax expense			60	60
Earnings from discontinued operations			52	52
Net earnings	429	111	165	705

Preferred stock dividends	2			2
Net earnings applicable to common stockholders	$ 427	111	165	703
Capital expenditures, continuing operations	$ 931	326	85	1,342

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	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2007:				
Revenues:				
Oil sales	$ 898	562	1,001	2,461
Gas sales	2,733	1,048	7	3,788
NGL sales	509	134		643
Marketing and midstream revenues	1,244	29		1,273
Total revenues	5,384	1,773	1,008	8,165
Expenses and other income, net:				
Lease operating expenses	751	460	115	1,326
Production taxes	165	3	87	255
Marketing and midstream operating costs and expenses	900	12		912
Depreciation, depletion and amortization of oil and gas properties	1,230	535	172	1,937
Depreciation and amortization of non-oil and gas properties	130	15	1	146
Accretion of asset retirement obligation	29	23	3	55
General and administrative expenses	278	83	(3)	358
Interest expense	174	151		325
Change in fair value of financial instruments	(30)	(1)		(31)
Other income, net	(28)	(11)	(32)	(71)
Total expenses and other income, net	3,599	1,270	343	5,212
Earnings from continuing operations before income tax expense	1,785	503	665	2,953
Income tax expense (benefit):				
Current	120	145	194	459
Deferred	467	3	(18)	452
Total income tax expense	587	148	176	911
Earnings from continuing operations	1,198	355	489	2,042
Discontinued operations:				
Earnings from discontinued operations before income tax expense			442	442
Income tax expense			194	194
Earnings from discontinued operations			248	248
Net earnings	1,198	355	737	2,290
Preferred stock dividends	7			7

Net earnings applicable to common stockholders	$ 1,191	355	737	2,283
Capital expenditures, before revision of future ARO	$ 3,204	952	329	4,485
Revision of future ARO	210	99	2	311
Capital expenditures, continuing operations	$ 3,414	1,051	331	4,796

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

	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2006:				
Revenues:				
Oil sales	$ 956	463	387	1,806
Gas sales	2,577	1,122	10	3,709
NGL sales	414	159		573
Marketing and midstream revenues	1,237	24		1,261
Total revenues	5,184	1,768	397	7,349
Expenses and other income, net:				
Lease operating expenses	601	399	36	1,036
Production taxes	182	4	75	261
Marketing and midstream operating costs and expenses	917	7		924
Depreciation, depletion and amortization of oil and gas properties	943	484	53	1,480
Depreciation and amortization of non-oil and gas properties	113	13	1	127
Accretion of asset retirement obligation	19	16		35
General and administrative expenses	221	66	(3)	284
Interest expense	144	171		315
Change in fair value of financial instruments	83	(2)		81
Reduction of carrying value of oil and gas properties			36	36
Other income, net	(27)	(11)	(48)	(86)
Total expenses and other income, net	3,196	1,147	150	4,493
Earnings from continuing operations before income tax expense (benefit)	1,988	621	247	2,856
Income tax expense (benefit):				
Current	281	111	79	471
Deferred	398	(121)	(24)	253
Total income tax expense (benefit)	679	(10)	55	724
Earnings from continuing operations	1,309	631	192	2,132
Discontinued operations:				
Earnings from discontinued operations before income tax expense			337	337
Income tax expense			205	205
Earnings from discontinued operations			132	132
Net earnings	1,309	631	324	2,264

Preferred stock dividends	7			7
Net earnings applicable to common stockholders	$ 1,302	631	324	2,257
Capital expenditures, before revision of future ARO	$ 4,758	1,296	229	6,283
Revision of future ARO	64	71		135
Capital expenditures, continuing operations	$ 4,822	1,367	229	6,418

14. Subsequent Event Master Limited Partnership

Devon announced on July 18, 2007 its plan to form a new, publicly traded master limited partnership (MLP). The proposed MLP was expected to initially own a minority interest in Devon s U.S. onshore marketing and midstream business. On November 7, 2007, Devon announced that it had decided not to proceed at this time with its plans to form this MLP. This decision was based primarily on a change in public market conditions for MLPs and other yield-driven investments subsequent to Devon s announcement of the proposed MLP.

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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 for the three-month and nine-month periods ended September 30, 2007, compared to the three-month and nine-month periods ended September 30, 2006, and in our financial condition since December 31, 2006. It is presumed that readers have read or have access to our 2006 Annual Report on Form 10-K which includes disclosures regarding critical accounting policies as part of Management s Discussion and Analysis of Financial Condition and Results of Operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

Overview

The following summarizes our performance for the three months and nine months ended September 30, 2007 compared to the three months and nine months ended September 30, 2006:

Net earnings and earnings per share both increased 4% and 1% during the third quarter of 2007 and the first nine months of 2007, respectively.

Net cash provided by operating activities increased $227 million, or 5%, during the first nine months of 2007.

Production increased 10% to 618 thousand barrels per day for the third quarter of 2007 and increased 12% to 608 thousand barrels per day for the first nine months of 2007.

Combined realized price for oil, gas and NGLs increased 2% and 1% for the third quarter of 2007 and the first nine months of 2007, respectively.

Marketing and midstream operating profit increased 19% and 7% during the third quarter of 2007 and the first nine months of 2007, respectively.

Per unit operating costs increased 15% and 14% for the third quarter and first nine months of 2007, respectively.

Capital expenditures for oil and gas exploration and development activities were $1.4 billion during the third quarter of 2007 and $4.1 billion during the first nine months of 2007.

On November 14, 2006, we announced our plans to divest our operations in Egypt. On January 23, 2007, we announced our plans to divest our operations in West Africa. Pursuant to accounting rules for discontinued operations, we have classified all 2007 and prior period amounts related to our operations in Egypt and West Africa as discontinued operations.

On October 4, 2007, we closed the sale of our Egyptian operations and received proceeds of $341 million. As a result of this sale, we will record an after-tax gain related to this transaction of approximately $130 million in the fourth quarter of 2007.

We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the properties in the West African divestiture package. We expect to complete these sales during the first half of 2008.

On October 25, 2007, the Alberta government proposed increases to the royalty rates on oil and natural gas production beginning in 2009. We believe this proposal would reduce future earnings and cash flows from our oil and gas properties located in Alberta. Additionally, assuming all other factors are equal, higher royalty rates would likely result in lower levels of capital investment in Alberta relative to our other areas of operation. However, the magnitude of the potential impact, which will depend on the final form of enacted legislation and other factors which impact the relative expected economic returns of capital projects, cannot be reasonably estimated at this time.

A more complete overview and discussion of full-year expectations can be found in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2006 Annual Report on Form 10-K and in our Current Report on Form 8-K dated November 7, 2007.

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Results of Operations

Revenues

The three-month and nine-month comparisons of production and price changes are shown in the following tables. The amounts for all periods presented exclude our Egyptian and West African operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Change[2]	2007	2006	Change[2]
Production						
Oil (MMBbls)	13	11	+23%	41	31	+35%
Gas (Bcf)	223	210	+6%	637	599	+6%
NGLs (MMBbls)	7	5	+9%	19	17	+8%
Oil, Gas and NGLs (MMBoe)[1]	57	52	+10%	166	148	+12%
Average Prices						
Oil (Per Bbl)	$ 67.41	63.77	+6%	$ 59.88	59.43	+1%
Gas (Per Mcf)	5.31	5.63	-6%	5.95	6.19	-4%
NGLs (Per Bbl)	38.34	34.98	+10%	34.31	32.99	+4%
Oil, Gas and NGLs (Per Boe)[1]	40.99	40.24	+2%	41.53	41.23	+1%
Revenues ($ in millions)						
Oil	$ 905	696	+30%	$ 2,461	1,806	+36%
Gas	1,182	1,186		3,788	3,709	+2%
NGLs	242	204	+19%	643	573	+12%
Oil, Gas and NGLs	$ 2,329	2,086	+12%	$ 6,892	6,088	+13%

	Domestic					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Change[2]	2007	2006	Change[2]
Production						
Oil (MMBbls)	5	5	+2%	14	15	-4%
Gas (Bcf)	164	149	+10%	465	415	+12%
NGLs (MMBbls)	6	4	+15%	16	14	+13%
Oil, Gas and NGLs (MMBoe)[1]	38	35	+9%	107	98	+10%
Average Prices						
Oil (Per Bbl)	$ 73.19	68.27	+7%	$ 63.01	64.30	-2%
Gas (Per Mcf)	5.28	5.73	-8%	5.88	6.21	-5%
NGLs (Per Bbl)	36.78	32.41	+13%	32.68	30.06	+9%
Oil, Gas and NGLs (Per Boe)[1]	37.81	38.86	-3%	38.56	40.34	-4%

Revenues ($ in millions)						
Oil	$ 359	328	+9%	$ 898	956	-6%
Gas	867	856	+1%	2,733	2,577	+6%
NGLs	196	151	+30%	509	414	+23%
Oil, Gas and NGLs	$ 1,422	1,335	+6%	$ 4,140	3,947	+5%

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	Canada					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Change[2]	2007	2006	Change[2]
Production						
Oil (MMBbls)	4	3	+32%	12	9	+24%
Gas (Bcf)	59	61	-5%	171	183	-7%
NGLs (MMBbls)	1	1	-16%	3	3	-12%
Oil, Gas and NGLs (MMBoe)[1]	15	14	+2%	43	43	-1%
Average Prices						
Oil (Per Bbl)	$ 53.40	54.85	-3%	$ 48.01	49.06	-2%
Gas (Per Mcf)	5.40	5.40		6.16	6.14	
NGLs (Per Bbl)	46.77	45.23	+3%	42.36	44.20	-4%
Oil, Gas and NGLs (Per Boe)[1]	39.28	38.34	+2%	40.33	40.11	+1%
Revenues ($ in millions)						
Oil	$ 224	174	+29%	$ 562	463	+21%
Gas	312	329	-5%	1,048	1,122	-7%
NGLs	46	53	-13%	134	159	-16%
Oil, Gas and NGLs	$ 582	556	+5%	$ 1,744	1,744	

	International					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Change[2]	2007	2006	Change[2]
Production						
Oil (MMBbls)	4	3	+48%	15	7	+149%
Gas (Bcf)			+74%	1	1	-19%
NGLs (MMBbls)			N/M			N/M
Oil, Gas and NGLs (MMBoe)[1]	4	3	+48%	16	7	+142%
Average Prices						
Oil (Per Bbl)	$ 74.43	66.00	+13%	$ 66.10	63.59	+4%
Gas (Per Mcf)	6.61	5.11	+29%	5.73	6.34	-10%
NGLs (Per Bbl)			N/M			N/M
Oil, Gas and NGLs (Per Boe)[1]	73.77	65.42	+13%	65.66	62.53	+5%
Revenues ($ in millions)						
Oil	$ 322	194	+67%	$ 1,001	387	+159%
Gas	3	1	+125%	7	10	-26%
NGLs			N/M			N/M

Oil, Gas and NGLs	$ 325	195	+67%	$ 1,008	397	+154%

(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 natural 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.

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The following tables include the effect of our financial hedging activities for the three months and nine months ended September 30, 2007 and 2006, respectively.

	Three Months Ended September 30, 2007		Nine Months Ended September 30, 2007	
	With Hedges	Without Hedges	With Hedges	Without Hedges
Oil (per Bbl)	$67.41	67.41	59.88	59.88
Gas (per Mcf)	$ 5.31(1)	5.28	5.95(1)	5.94
NGLs (per Bbl)	$38.34	38.34	34.31	34.31
Oil, Gas and NGLs (per Boe)	$40.99	40.86	41.53	41.52

(1) The average gas sales price with the effect of hedges includes both the effect due to unrealized losses and the effect due to cash settlements on our hedging contracts. Excluding an unrealized loss of $6 million for the three months ended September 30, 2007 and an unrealized loss of $30 million for the nine months ended September 30, 2007, our average realized gas sales price would have been $5.34 and $6.00, respectively.

	Three Months Ended September 30, 2006		Nine Months Ended September 30, 2006	
	With Hedges	Without Hedges	With Hedges	Without Hedges
Oil (per Bbl)	$63.77	63.77	59.43	59.43

Gas (per Mcf)	$ 5.63[(1)]	5.61	6.19[(1)]	6.18
NGLs (per Bbl)	$34.98	34.98	32.99	32.99
Oil, Gas and NGLs (per Boe)	$40.24	40.14	41.23	41.19

(1) The average gas sales price with the effect of hedges includes both the effect due to unrealized gains and the effect due to cash settlements on our hedging contracts. Excluding an unrealized gain of $5 million for both the three months and nine months ended September 30, 2006, our average realized gas sales price would have been $5.61 and $6.18, respectively.

The following tables summarize the changes in our oil, gas and NGL revenues between the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30, 2007			
	Oil	Gas	NGL	Total
		(In millions)		
2006 revenues	$ 696	1,186	204	2,086
Changes due to volumes	160	67	18	245
Changes due to prices	49	(60)	20	9
Changes due to unrealized hedge losses		(11)		(11)
2007 revenues	$ 905	1,182	242	2,329

	Nine Months Ended September 30, 2007			
	Oil	Gas	NGL	Total
		(In millions)		
2006 revenues	$ 1,806	3,709	573	6,088
Changes due to volumes	637	230	46	913
Changes due to prices	18	(116)	24	(74)
Changes due to unrealized hedge losses		(35)		(35)

2007 revenues	$ 2,461	3,788	643	6,892

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Oil Revenues

Production increases of 23% and 35% in the third quarter of 2007 and first nine months of 2007 were the primary causes of our increased oil revenues in these periods. The increased 2007 production was primarily from our properties in Azerbaijan where we achieved payout of certain carried interests in the last half of 2006. The remainder of the 2007 increases were primarily related to increased production from our Lloydminster area in Canada.

Gas Revenues

A 13 Bcf increase in production caused gas revenues to increase by $67 million during the third quarter of 2007. Our drilling and development program in the Barnett Shale field in north Texas contributed 17 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.

A 38 Bcf increase in production caused gas revenues to increase by $230 million during the first nine months of 2007. Our drilling and development program in the Barnett Shale field in north Texas contributed 36 Bcf to the gas production increase. The June 2006 Chief Holdings LLC (Chief) acquisition also contributed 12 Bcf of increased production. These increases and the effect of new drilling and development in our other North American properties were partially offset by natural production declines.

Marketing and Midstream Revenues and Operating Costs and Expenses

The following table details the changes in our marketing and midstream revenues and operating costs and expenses between the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006. The changes due to prices in the table represent the effect on both revenues and expenses due to changes in the market prices for natural gas and NGLs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	Revenues	**Expenses**	**Revenues**	**Expenses**
2006 marketing and midstream	$ 413	301	1,261	924
Changes due to volumes	30	6	41	33
Changes due to prices	(9)	(6)	(30)	(45)
Other			1	
2007 marketing and midstream	$ 434	301	1,273	912

Volume increases in our third-party crude oil and NGL marketing activities caused both revenues and expenses to increase in the third quarter of 2007 and first nine months of 2007. Lower natural gas prices partially offset by higher NGL prices caused revenues and expenses to decrease in the third quarter of 2007 and the first nine months of 2007.

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Oil, Gas and NGL Production and Operating Expenses

The three-month and nine-month comparisons of oil, gas and NGL production and operating expenses are shown in the table below.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Change[1]	2007	2006	Change[1]
Production and operating expenses ($ in millions):						
Lease operating expenses	$ 457	363	+26%	$ 1,326	1,036	+28%
Production taxes	85	92	-8%	255	261	-2%
Total production and operating expenses	$ 542	455	+19%	$ 1,581	1,297	+22%
Production and operating expenses per Boe:						
Lease operating expenses	$ 8.04	7.01	+15%	$ 7.99	7.02	+14%
Production taxes	1.49	1.77	-16%	1.54	1.77	-13%
Total production and operating expenses per Boe	$ 9.53	8.78	+9%	$ 9.53	8.79	+8%

(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 increased $94 million and $290 million in the third quarter of 2007 and the first nine months of 2007 largely due to the continued effects of higher commodity prices. Commodity price increases in 2005 and the first nine months of 2006 contributed to industry-wide inflationary pressures on materials and personnel costs. Although commodity prices have somewhat stabilized compared to the first nine months of 2006, demand for materials, equipment and personnel continued to increase subsequent to September 30, 2006. In addition, consideration of continued higher commodity prices contributed to our decision to perform more well workovers and maintenance projects in 2007 to maintain or improve production volumes.

Lease operating expenses also increased $16 million and $77 million in the third quarter of 2007 and the first nine months ended 2007, respectively, as a result of payouts of our carried interests in Azerbaijan in the last half of 2006. The June 2006 Chief acquisition also increased our lease operating expenses by $15 million in the first nine months ended 2007. Our 10% and 12% production growth in the third quarter and the first nine months of 2007, respectively, were also key contributors to the increase in our lease operating expenses. Furthermore, changes in the exchange rate between the U.S. and Canadian dollar also caused lease operating expenses to increase $12 million and $13 million in the third quarter of 2007 and the first nine months of 2007, respectively.

The following table details the changes in production taxes between the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,	Nine Months Ended September 30,
	(In millions)	
2006 production taxes	$ 92	261
Change due to revenues	11	35
Change due to rate	(18)	(41)
2007 production taxes	$ 85	255

Our lower production tax rates in 2007 are primarily due to the increase in Azerbaijan revenues subsequent to the payouts of our carried interests in Azerbaijan in the last half of 2006. Our Azerbaijan revenues are not subject to production taxes. Therefore, the increased revenues generated in Azerbaijan in 2007 caused our overall rate of production taxes to decrease.

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Depreciation, Depletion and Amortization Expenses (DD&A)

The following table details the changes in DD&A of oil and gas properties between the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,	Nine Months Ended September 30,
	(In millions)	
2006 DD&A	$ 547	1,480
Change due to volumes	53	184
Change due to rate	105	273
2007 DD&A	$ 705	1,937

Oil and gas property related DD&A increased $105 million in the third quarter of 2007 due to an increase in the DD&A rate from $10.55 per Boe to $12.41 per Boe. Oil and gas property related DD&A increased $273 million in the first nine months of 2007 due to an increase in the DD&A rate from $10.03 per Boe to $11.67 per Boe. The largest contributor to the rate increases were inflationary pressure on both the costs incurred during 2006 and 2007 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Rising estimates for future asset retirement obligations also caused the rate to increase. Other factors contributing to the rate increase include the transfer of previously unproved costs to the depletable base as a result of drilling activities subsequent to September 30, 2006 and the effects of changes in the exchange rate between the U.S. and Canadian dollar.

General and Administrative Expenses (G&A)

The following schedule includes the components of G&A expense for the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Gross G&A	$ 239	190	673	526
Capitalized G&A	(84)	(59)	(230)	(162)
Reimbursed G&A	(29)	(27)	(85)	(80)
Net G&A	$ 126	104	358	284

Gross G&A increased $49 million and $147 million in the third quarter and first nine months of 2007, respectively, compared to the same periods of 2006. Higher employee compensation and benefits costs related to our growth and industry inflation caused gross G&A to increase $37 million and $110 million, respectively. The $25 million and $68 million increases in capitalized G&A during the third quarter and first nine months of 2007, respectively, are also primarily due to higher employee compensation and benefits costs.

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Interest Expense

The following schedule includes the components of interest expense for the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Interest based on debt outstanding	$ 127	126	380	359
Capitalized interest	(26)	(21)	(73)	(57)
Other	7	7	18	13
Total	$ 108	112	325	315

Interest based on debt outstanding increased in the first nine months of 2007 primarily due to the effect of commercial paper borrowings related to the June 2006 acquisition of the Chief properties. This increase was partially offset by the effect of $680 million of debt maturities in the last half of 2006.

Capitalized interest in the third quarter and the first nine months of 2007 increased primarily due to costs related to our Jackfish development project and the related Access Pipeline in Canada, as well as development projects in the Gulf of Mexico and Brazil.

Change in Fair Value of Financial Instruments

The following schedule includes the components of the change in fair value of financial instruments for the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Option embedded in exchangeable debentures	$ 111	22	255	83
Investment in Chevron common stock	(133)		(285)	
Interest rate swaps			(1)	(2)
Total (income) expense	$ (22)	22	(31)	81

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron common stock. These expenses were caused primarily by increases in the price of Chevron s common stock.

During the third quarter of 2007, certain holders of exchangeable debentures exercised their option to convert their debentures prior to the August 15, 2008 maturity date. We have the option to settle conversions of the exchangeable debentures with either shares of Chevron common stock or cash equal to the market value of Chevron common stock at the time of conversion. We paid $166 million in cash to settle the conversions in the third quarter of 2007. As a result of the $166 million payment, we retired outstanding exchangeable debentures totaling $104 million as well as the related embedded derivative option with a value of $62 million.

As discussed in Note 1 to our financial statements, effective January 1, 2007 as a result of our adoption of Statement No. 159, we began recognizing unrealized gains and losses on our investment in Chevron common stock in net earnings rather than as part of other comprehensive income. The change in the fair value of our investment in Chevron common stock resulted from increases in the price of Chevron s common stock during the third quarter and first nine months of 2007.

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Reduction of Carrying Value of Oil and Gas Properties

The following schedule summarizes the reductions of carrying value of oil and gas properties for the third quarter and first nine months of 2006. We had no such reductions in 2007.

	Three Months Ended September 30, 2006		Nine Months Ended September 30, 2006	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
Brazil	$		16	16
Russia	20	10	20	10
Total	$ 20	10	36	26

As a result of a decline in projected future net cash flows, our Russian properties exceeded the ceiling by $10 million in the third quarter of 2006. Therefore, in the third quarter of 2006, we recognized a $20 million reduction of the carrying value of our oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

During the second quarter of 2006, we drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, we recognized a $16 million impairment of our investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to our Polvo development project in Brazil.

Other Income, net

The following schedule includes the components of other income for the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Interest and dividend income	$ 24	22	63	78
Net gain on sales of non-oil and gas property and equipment			1	5
Other	4	6	7	3
Total	$ 28	28	71	86

The decrease in interest and dividend income in the first nine months of 2007 were primarily due to a decrease in interest-bearing cash and short-term investment balances subsequent to the June 2006 Chief acquisition.

Income Taxes

The effective tax rate was 33% in the third quarter of 2007 and 28% in the third quarter of 2006. The effective tax rate was 31% in the first nine months of 2007 and 25% in the first nine months of 2006.

The rates for the third quarter and first nine months of 2007 were lower than the statutory federal tax rate primarily due to the effects of certain U.S. and Canadian deductions. The 2007 rates were further lowered due to the increase in revenues generated in Azerbaijan, whose statutory rate is 25%, and the effect of a statutory rate reduction enacted by the Canadian Federal government in the second quarter of 2007. As a result of the 2007 Canadian rate reduction, we recorded a $30 million tax benefit in such quarter.

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The rates for the third quarter and first nine months of 2006 were lower than the statutory federal tax rate primarily due to the effects of tax law changes. During the second quarter of 2006, the Canadian Federal and Alberta provincial governments enacted statutory rate reductions. As a result, we recorded a $243 million deferred tax benefit in such quarter. Also during the second quarter of 2006, the state of Texas enacted a new income-based tax that replaces a previous franchise tax. The new tax is effective January 1, 2007. As a result of the enactment of the tax in the second quarter of 2006, we recorded $39 million of deferred tax expense in such quarter. In addition, in the third quarter of 2006 we recognized an $11 million deferred tax benefit related to the expected utilization of a net operating loss carryforward that has been generated in Brazil.

Earnings from Discontinued Operations

On November 14, 2006, we announced our plans to divest our operations in Egypt. On January 23, 2007, we announced our plans to divest our operations in West Africa. Pursuant to accounting rules for discontinued operations, we have classified all 2007 and prior period amounts related to our operations in Egypt and West Africa as discontinued operations.

On October 4, 2007, we closed the sale of our Egyptian operations and received proceeds of $341 million. As a result of this sale, we will record an after-tax gain related to this transaction of approximately $130 million in the fourth quarter of 2007.

We are finalizing purchase and sales agreements and obtaining the necessary partner and government approvals for the properties in the West African divestiture package. We expect to complete these sales during the first half of 2008.

Following are the components of earnings from discontinued operations for the three months ended September 30, 2007 and 2006 and the nine months ended September 30, 2007 and 2006.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Earnings from discontinued operations before income taxes	$ 177	112	442	337
Income tax expense	86	60	194	205
Earnings from discontinued operations	$ 91	52	248	132

Earnings from discontinued operations increased $39 million in the third quarter of 2007 primarily due to the net effect of the following factors. First, pursuant to accounting rules for discontinued operations, we ceased recording DD&A in November 2006 for our Egypt property and equipment and in January 2007 for our West Africa property and equipment. During the third quarter of 2006, we recorded $57 million of DD&A associated with these properties. Second, as a result of unsuccessful exploratory activities in Egypt during 2005 and 2006, the net book value of our Egyptian oil and gas properties, less related deferred income taxes, exceeded the calculated full cost ceiling by $18 million as of September 30, 2006. Therefore, in the third quarter of 2006, we recognized a $31 million reduction of the book value of our oil and gas properties in Egypt, offset by a $13 million deferred income tax benefit. The after-tax increase in earnings caused by these factors was partially offset by a decrease due to a decline in production.

Earnings from discontinued operations increased $116 million in the first nine months of 2007 primarily due to the net effect of the following factors. First, during the first nine months of 2006, we recorded $187 million of DD&A associated with our Egypt and West Africa properties. In addition, due to unsuccessful drilling activities in Nigeria, in the first quarter of 2006, we recognized an $85 million impairment of our investment in Nigeria equal to the costs to drill two dry holes and a proportionate share of block-related costs. There was no income tax benefit related to this impairment. The after-tax increase in earnings caused by these factors was partially offset by a

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decrease due to a decline in production. Additionally, based on recent drilling activities in Nigeria, we reduced the carrying value of our Nigerian assets held for sale in the second quarter of 2007. As a result, earnings from discontinued operations in the first nine months of 2007 include a $13 million after-tax loss ($64 million pre-tax).

Capital Resources, Uses and Liquidity

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

Sources and Uses of Cash

	Nine Months Ended September 30,	
	2007	**2006**
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 4,739	4,413
Net commercial paper borrowings		1,439
Net credit facility borrowings	400	
Sales of property and equipment	39	36
Stock option exercises	71	53
Net decrease in short-term investments	233	556
Other	20	14
Total sources of cash and cash equivalents	5,502	6,511
Uses of cash and cash equivalents:		
Capital expenditures	(4,477)	(5,959)
Net commercial paper repayments	(129)	
Debt repayments	(166)	(860)
Repurchases of common stock	(133)	(253)
Dividends	(193)	(155)
Total uses of cash and cash equivalents	(5,098)	(7,227)
Increase (decrease) from continuing operations	404	(716)
Increase from discontinued operations	217	282
Effect of foreign exchange rates	44	24
Net increase (decrease) in cash and cash equivalents	$ 665	(410)
Cash and cash equivalents at end of period	$ 1,421	1,196
Short-term investments at end of period	$ 341	124

Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) continued to be the primary source of capital and liquidity in the first nine months of 2007. 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 such noncash expenses as DD&A,

financial instrument fair value changes, property impairments and deferred income tax expense. As a result, our operating cash flow increased in 2007 primarily due to the increase in earnings as discussed in the Results of Operations section of this report.

Additionally, during 2007 and 2006, operating cash flow was primarily used to fund our capital expenditures. Excluding the June 2006 $2.0 billion Chief acquisition, our operating cash flow was sufficient to fund our 2007 and 2006 capital expenditures.

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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. Additionally, we invest in highly liquid, 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.

During 2007, we borrowed $0.4 billion under our unsecured revolving line of credit and reduced our short-term investment balances by $0.2 billion. These sources of cash combined with our operating cash flow in excess of capital expenditures were primarily used to fund long-term debt repayments, net commercial paper repayments, common stock repurchases and dividends on common and preferred stock.

As of September 30, 2007, our credit facility borrowings had an average interest rate of 5.85% and our commercial paper borrowings had an average interest rate of 5.66%.

During 2006, we borrowed $1.4 billion under our commercial paper program and reduced our short-term investment balances by $0.6 billion. These sources of cash were largely used to fund the $2.0 billion acquisition of Chief in June 2006. Also during 2006, we supplemented operating cash flow with cash on hand. Our operating cash flow in excess of capital expenditures, excluding Chief, and cash on hand were primarily used to fund scheduled long-term debt maturities, common stock repurchases and dividends on common and preferred stock.

Capital Expenditures

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling or development of oil and gas properties, which totaled $4.1 billion and $5.7 billion in the first nine months of 2007 and 2006, respectively. The 2006 capital expenditures include $2.0 billion related to the acquisition of the Chief properties. Excluding the Chief acquisition, the increase in such capital expenditures is primarily due to an increase in drilling and development in the Barnett Shale field in north Texas. Additionally, capital expenditures also increased from our properties in Azerbaijan where we achieved payout of certain carried interests in the last half of 2006.

Our 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. These midstream facilities exist primarily to support our oil and gas development operations. Such expenditures were $254 million and $228 million in the first nine months of 2007 and 2006, respectively. The majority of our 2007 and 2006 expenditures related to development activities in the Barnett Shale, the Woodford Shale in eastern Oklahoma and Jackfish in Canada.

Debt Repayments

During the third quarter of 2007, certain holders of exchangeable debentures exercised their option to convert their debentures prior to the August 15, 2008 maturity date. We have the option to settle conversions of the exchangeable debentures with either shares of Chevron common stock or cash equal to the market value of Chevron common stock at the time of conversion. We paid $166 million in cash to settle the conversions in the third quarter of 2007.

During 2006, we retired the $500 million 2.75% notes and the $178 million ($200 million Canadian) 6.55% debt on their scheduled maturity dates. We also repaid $180 million of debt acquired in the Chief acquisition.

Repurchases of Common Stock

On June 6, 2007, our Board of Directors approved an ongoing, annual stock repurchase program to offset dilution resulting from restricted stock issued to, and options exercised by, employees. The new repurchase program authorizes the repurchase of up to 4.5 million shares in 2007 and is in addition to our 50 million share repurchase program approved in August 2005.

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During the first nine months of 2007, we repurchased 1.8 million shares at a cost of $136 million under the program authorized in June 2007. Included in the $136 million is $3 million for unsettled purchases as of September 30, 2007. During the first nine months of 2006, we repurchased 4.2 million shares at a cost of $253 million under the program authorized in August 2005.

Dividends

Our common stock dividends were $186 million and $148 million in the first nine months of 2007 and 2006, respectively. We also paid $7 million of preferred stock dividends in 2007 and 2006. The 2007 increase in common stock dividends was primarily related to a 25% increase in the quarterly dividend rate in the first quarter of 2007.

Liquidity

Our primary source of capital and liquidity has been our operating cash flow. Additionally, we maintain revolving lines of credit and a commercial paper program which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include cash and short-term investments on hand and the issuance of equity securities and long-term debt. Another major source of near-term liquidity will be proceeds from the sales of our operations in Egypt and West Africa.

Operating Cash Flow

We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. To mitigate some of the risk inherent in prices, we have utilized price collars to set minimum and maximum prices on a portion of our production. We have also utilized various price swap contracts and fixed-price physical delivery contracts. Based on contracts currently in place, approximately 5% of our estimated 2007 natural gas production from continuing operations (3% of our total oil, gas and NGL production from continuing operations) is subject to either price collars, swaps or fixed-price contracts.

Credit Lines

In April 2007, we extended the maturity of our existing $2.5 billion five-year, syndicated, unsecured revolving line of credit (the Senior Credit Facility) from April 7, 2011 to April 7, 2012.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65%. As of September 30, 2007, we were in compliance with this covenant. Our debt-to-capitalization ratio at September 30, 2007, as calculated pursuant to the terms of the agreement, was 24.8%.

On August 7, 2007, we established a new $1.5 billion 364-day, syndicated, unsecured revolving senior credit facility (the Short-Term Facility). This new facility provides us with provisional interim liquidity until we receive the proceeds from divestitures of assets in Africa. The Short-Term Facility was also used to support an increase in our commercial paper program from $2 billion to $3.5 billion.

The Short-Term Facility matures 364 days from the closing date. On the maturity date, all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to the maturity date, we have the option to convert any outstanding principal amount of loans under the Short-Term Facility to a term loan which will be repayable in a single payment 364 days from the maturity date.

Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally less than the prime rate. We may also elect to borrow at the prime rate. The Short-Term Facility currently provides for an annual facility fee of approximately $1.0 million that is payable quarterly in arrears.

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The agreement governing the Short-Term Facility contains substantially the same covenants and restrictions as our existing Senior Credit Facility, including a maximum allowed debt-to-capitalization ratio of 65% as defined in the agreement.

As of September 30, 2007, our combined available capacity under these credit facilities was $1.6 billion.

Debt Ratings

During September 2007, our senior unsecured long term debt rating was upgraded by Moody s from Baa2 to Baa1 with a stable outlook. This upgrade was primarily due to improved organic reserves replacement, production growth and reduced leverage. We are not aware of any potential downgrades contemplated by the rating agencies as of September 30, 2007.

Exchangeable Debentures

As of September 30, 2007, our outstanding debt includes Chevron exchangeable debentures with a scheduled maturity date of August 15, 2008. Although these debentures are now due within one year, we continue to classify this debt as long-term because we have the intent and ability to refinance these debentures on a long-term basis with the available capacity under our existing credit facilities or other long-term financing arrangements.

Canadian Royalties

On October 25, 2007, the Alberta government proposed increases to the royalty rates on oil and natural gas production beginning in 2009. We believe this proposal would reduce future earnings and cash flows from our oil and gas properties located in Alberta. Additionally, assuming all other factors are equal, higher royalty rates would likely result in lower levels of capital investment in Alberta relative to our other areas of operation. However, the magnitude of the potential impact, which will depend on the final form of enacted legislation and other factors which impact the relative expected economic returns of capital projects, cannot be reasonably estimated at this time.

Master Limited Partnership

We announced on July 18, 2007 our plan to form a new, publicly traded master limited partnership (MLP). The proposed MLP was expected to initially own a minority interest in our U.S. onshore marketing and midstream business. On November 7, 2007, we announced that we had decided not to proceed at this time with our plans to form this MLP. This decision was based primarily on a change in public market conditions for MLPs and other yield-driven investments subsequent to our announcement of the proposed MLP.

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

There have been no material changes to the information included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk in our 2006 Annual Report on Form 10-K.

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

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Exchange Act of 1934) were effective as of September 30, 2007 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the third quarter of 2007 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 2006 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 2006 Annual Report on Form 10-K.

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs[1]
July	527,300	$ 78.58	527,300	47,304,901
August	669,300	$ 75.12	669,300	46,635,601
September	361,500	$ 79.83	361,500	46,274,101
Total	1,558,100	$ 77.38	1,558,100	

(1) In August 2005, Devon s Board of Directors approved a stock repurchase program to repurchase up to 50 million shares of Devon s common stock. This program was suspended in 2006 as a result of the Chief acquisition. As of September 30, 2007, there were still 43,533,001 shares available for purchase under this program. On

June 6, 2007, Devon s Board of Directors approved an ongoing, annual stock repurchase program to offset dilution resulting from restricted stock issued to, and options exercised by, employees. The new repurchase program authorizes the repurchase of up to 4.5 million shares in 2007 and is in addition to the 50 million share repurchase program that was authorized in August 2005. The shares purchased in the third quarter relate to the program authorized in June 2007.

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

None

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

None

Item 5. ***Other Information***

None

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Item 6. ***Exhibits***

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

Exhibit Number	Description
10.1	Credit Agreement dated as of August 7, 2007 among Registrant as Borrower, Bank of America, N.A. as Administrative Agent, JPMorgan Chase Bank, N.A. as Syndication Agent, and The Other Lenders Party Hereto, Banc of America Securities LLC and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Book Managers for the $1.5 Billion Senior Credit Facility (incorporated by reference to Exhibit 10.1 to Registrant s Form 8-K filed on August 9, 2007).
10.2	First Amendment to Amended and Restated Credit Agreement dated as of June 1, 2006, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment.
10.3	Second Amendment to Amended and Restated Credit Agreement dated as of September 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment.
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, 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, 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.

SIGNATURES

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

DEVON ENERGY CORPORATION

Date: November 7, 2007

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

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