DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

Filed 11/02/06 for the Period Ending 09/30/06

Address	333 W. SHERIDAN AVENUE OKLAHOMA CITY, OK 73102
Telephone	4055528183
CIK	0001090012
Symbol	DVN
SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

Filed 11/2/2006 For Period Ending 9/30/2006

Address	20 N BROADWAY STE 1500
	OKLAHOMA CITY, Oklahoma 73102
Telephone	405-235-3611
CIK	0001090012
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2006

or

☐ **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 *(State or Other Jurisdiction of Incorporation or Organization)*	**73-1567067** *(I.R.S. Employer Identification Number)*
20 North Broadway **Oklahoma City, Oklahoma** *(Address of Principal Executive Offices)*	**73102-8260** *(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 ☑ No ☐

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

The number of shares outstanding of Registrant's common stock, par value $0.10, as of September 30, 2006, was 442,001,000.

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DEVON ENERGY CORPORATION
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to the Securities and Exchange Commission

DEFINITIONS

As used in this document:

"AECO" means the price of gas delivered onto the NOVA Gas Transmission Ltd. System.

"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.

"NYMEX" means New York Mercantile Exchange.

"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.

PART I. Financial Information

Item 1. ***Financial Statements***

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	September 30, 2006	December 31, 2005
	(Unaudited)	
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,196	1,606
Short-term investments	124	680
Accounts receivable	1,317	1,601
Deferred income taxes	71	158
Other current assets	228	161
Total current assets	2,936	4,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,862 and $2,747 excluded from amortization in 2006 and 2005, respectively)	41,247	34,246
Less accumulated depreciation, depletion and amortization	17,150	15,114
	24,097	19,132
Investment in Chevron Corporation common stock, at fair value	920	805
Goodwill	5,822	5,705
Other assets	457	425
Total assets	$ 34,232	30,273
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,133	947
Revenues and royalties due to others	524	666
Income taxes payable	278	293
Short-term debt	1,439	662
Accrued interest payable	79	127
Current portion of asset retirement obligation	45	50
Accrued expenses and other current liabilities	328	189
Total current liabilities	3,826	2,934
Debentures exchangeable into shares of Chevron Corporation common stock	723	709
Other long-term debt	5,239	5,248
Fair value of derivative financial instruments	204	125
Asset retirement obligation, long-term	864	618
Other liabilities	534	372
Deferred income taxes	5,625	5,405
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 442,010,000 in 2006 and 443,488,000 in 2005	44	44
Additional paid-in capital	6,791	6,928
Retained earnings	8,586	6,477
Accumulated other comprehensive income	1,796	1,414
Treasury stock, at cost: 9,000 shares in 2006 and 37,000 shares in 2005	(1)	(2)
Total stockholders' equity	17,217	14,862
Total liabilities and stockholders' equity	$ 34,232	30,273

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil sales	$ 910	643	2,482	1,908
Gas sales	1,191	1,466	3,725	3,913
NGL sales	204	190	573	492
Marketing and midstream revenues	417	405	1,276	1,210
Total revenues	2,722	2,704	8,056	7,523
Expenses and other income, net:				
Lease operating expenses	382	319	1,093	1,005
Production taxes	92	81	261	234
Marketing and midstream operating costs and expenses	303	294	930	921
Depreciation, depletion and amortization of oil and gas properties	604	493	1,667	1,528
Depreciation and amortization of non-oil and gas properties	44	40	129	119
Accretion of asset retirement obligation	13	12	37	35
General and administrative expenses	104	70	284	206
Interest expense	112	164	315	428
Effects of changes in foreign currency exchange rates	—	(15)	(1)	(4)
Change in fair value of derivative financial instruments	22	134	81	168
Reduction of carrying value of oil and gas properties	51	—	152	—
Other income, net	(27)	(27)	(85)	(179)
Total expenses and other income, net	1,700	1,565	4,863	4,461
Earnings before income tax expense	1,022	1,139	3,193	3,062
Income tax expense:				
Current	231	203	733	832
Deferred	86	192	196	270
Total income tax expense	317	395	929	1,102
Net earnings	705	744	2,264	1,960
Preferred stock dividends	2	2	7	7
Net earnings applicable to common stockholders	$ 703	742	2,257	1,953
Net earnings per average common share outstanding:				
Basic	$ 1.59	1.66	5.11	4.22
Diluted	$ 1.57	1.63	5.05	4.15
Weighted average common shares outstanding:				
Basic	441	446	441	463
Diluted	447	454	447	471

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (Unaudited)

	Preferred Stock	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders' Equity
				(In millions)			
Nine Months Ended September 30, 2006							
Balance as of December 31, 2005	$ 1	44	6,928	6,477	1,414	(2)	14,862
Comprehensive income:							
Net earnings	—	—	—	2,264	—	—	2,264
Other comprehensive income (loss), net of tax:							
Foreign currency translation adjustments	—	—	—	—	310	—	310
Change in fair value of derivative financial instruments	—	—	—	—	(1)	—	(1)
Unrealized gain on marketable securities	—	—	—	—	73	—	73
Other comprehensive income							382
Comprehensive income							2,646
Stock issued	—	—	53	—	—	—	53
Stock repurchased	—	—	—	—	—	(253)	(253)
Stock retired	—	—	(256)	—	—	256	—
Dividends on common stock	—	—	—	(148)	—	—	(148)
Dividends on preferred stock	—	—	—	(7)	—	—	(7)
Grant of restricted stock awards, net of cancellations	—	—	(3)	—	—	(2)	(5)
Stock option and restricted stock expense	—	—	55	—	—	—	55
Excess tax benefits related to share-based compensation	—	—	14	—	—	—	14
Balance as of September 30, 2006	$ 1	44	6,791	8,586	1,796	(1)	17,217
Nine Months Ended September 30, 2005							
Balance as of December 31, 2004	$ 1	48	9,002	3,693	930	—	13,674
Comprehensive income:							
Net earnings	—	—	—	1,960	—	—	1,960
Other comprehensive income (loss), net of tax:							
Foreign currency translation adjustments	—	—	—	—	193	—	193
Reclassification adjustment for derivative losses reclassified into oil and gas sales	—	—	—	—	335	—	335
Change in fair value of derivative financial instruments	—	—	—	—	(226)	—	(226)
Unrealized gain on marketable securities	—	—	—	—	111	—	111
Other comprehensive income							413
Comprehensive income							2,373
Stock issued	—	1	116	—	—	—	117
Stock repurchased	—	—	—	—	—	(2,129)	(2,129)
Stock retired	—	(4)	(1,558)	—	—	1,562	—
Dividends on common stock	—	—	—	(103)	—	—	(103)
Dividends on preferred stock	—	—	—	(7)	—	—	(7)
Restricted stock expense	—	—	19	—	—	—	19
Balance as of September 30, 2005	$ 1	45	7,579	5,543	1,343	(567)	13,944

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2006	2005
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net earnings	$ 2,264	1,960
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,796	1,647
Deferred income tax expense	196	270
Net gain on sales of non-oil and gas property and equipment	(5)	(145)
Reduction of carrying value of oil and gas properties	152	—
Other non-cash charges	165	224
Changes in assets and liabilities, net of effects of acquisitions of businesses:		
(Increase) decrease in:		
Accounts receivable	341	(164)
Other current assets	(55)	(33)
Long-term other assets	(56)	28
Increase (decrease) in:		
Accounts payable	(79)	133
Income taxes payable	(32)	(116)
Debt, including current maturities	—	(67)
Accrued interest and expenses	55	(53)
Long-term other liabilities	140	(32)
Net cash provided by operating activities	4,882	3,652
Cash flows from investing activities:		
Proceeds from sales of property and equipment	36	2,150
Capital expenditures, including acquisitions of businesses	(6,146)	(2,923)
Purchases of short-term investments	(1,868)	(3,501)
Sales of short-term investments	2,424	3,677
Net cash used in investing activities	(5,554)	(597)
Cash flows from financing activities:		
Proceeds from borrowings of debt, net of issuance costs	1,439	—
Principal payments on debt, including current maturities	(860)	(1,023)
Proceeds from exercise of stock options	53	117
Repurchase of common stock	(253)	(2,129)
Excess tax benefits related to share-based compensation	14	—
Dividends paid on common stock	(148)	(103)
Dividends paid on preferred stock	(7)	(7)
Net cash provided by (used in) financing activities	238	(3,145)
Effect of exchange rate changes on cash	24	33
Net decrease in cash and cash equivalents	(410)	(57)
Cash and cash equivalents at beginning of period	1,606	1,152
Cash and cash equivalents at end of period	$ 1,196	1,095

See accompanying notes to consolidated financial statements.

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

1. Summary of Significant Accounting Policies

The accompanying 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 2005 Annual Report on Form 10-K.

In the opinion of Devon's management, all adjustments (all of which are normal and recurring) have been made which are necessary to fairly state the consolidated financial position of Devon and its subsidiaries as of September 30, 2006, and the results of their operations and their cash flows for the three-month and nine-month periods ended September 30, 2006 and 2005.

Certain prior period amounts have been reclassified to conform to the current period presentation.

Earnings Per Share

The following table reconciles the net earnings 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, 2006 and 2005.

	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, 2006:			
Basic earnings per share	$ 703	441	$ 1.59
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	6	
Diluted earnings per share	$ 703	447	$ 1.57
Three Months Ended September 30, 2005:			
Basic earnings per share	$ 742	446	$ 1.66
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Diluted earnings per share	$ 742	454	$ 1.63

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

	Net Earnings Applicable to Common Stockholders	Weighted Average Common Shares Outstanding	Net Earnings Per Share
	(In millions, except per share amounts)		
Nine Months Ended September 30, 2006:			
Basic earnings per share	$ 2,257	441	$ 5.11
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	6	
Diluted earnings per share	$ 2,257	447	$ 5.05
Nine Months Ended September 30, 2005:			
Basic earnings per share	$ 1,953	463	$ 4.22
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Diluted earnings per share	$ 1,953	471	$ 4.15

Certain options to purchase shares of Devon's common stock are excluded from the dilution calculations because the options are antidilutive. During both the three-month and nine-month periods ended 2006, 2.6 million shares were excluded from the diluted earnings per share calculations. During the three-months and nine-months ended 2005, 4,000 shares and 7,000 shares, respectively, were excluded from the diluted earnings per share calculations.

Change in Accounting Principle

Effective January 1, 2006, Devon adopted Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment* , ("SFAS No. 123(R)"), using the modified prospective transition method. SFAS No. 123(R) requires equity-classified, share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant and to be expensed over the applicable vesting period. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized in compensation expense over the applicable vesting period. Also, any previously granted awards that are not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon Devon's adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), Devon accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, ("APB No. 25") and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

Had Devon elected the fair value provisions of SFAS No. 123(R), Devon's 2005 net earnings and net earnings per share would have differed from the amounts actually reported as shown in the following table.

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

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
	(In millions, except per share amounts)	
Net earnings available to common stockholders, as reported	$ 742	1,953
Add share-based employee compensation expense included in reported earnings, net of related tax expense	4	13
Deduct total share-based employee compensation expense determined under fair value based method for all awards, net of related tax expense	(10)	(30)
Net earnings available to common stockholders, pro forma	$ 736	1,936
Net earnings per share available to common stockholders:		
As reported:		
Basic	$ 1.66	4.22
Diluted	$ 1.63	4.15
Pro forma:		
Basic	$ 1.65	4.18
Diluted	$ 1.63	4.13

As a result of adopting SFAS No. 123(R) on January 1, 2006, Devon's earnings before income tax expense for the three-month and nine-month periods ended September 30, 2006 were $6 million and $17 million lower, respectively, than if Devon had continued to account for share-based compensation under APB No. 25. Also as a result of the adoption, net earnings for the three-month and nine-month periods ended September 30, 2006 were $4 million and $11 million lower, respectively, and the related basic and diluted earnings per share were approximately $0.01 and $0.02 per share lower for the respective 2006 periods. Prior to the adoption of SFAS No. 123(R), Devon presented all tax benefits of deductions resulting from the exercise of stock options as operating cash inflows in the statement of cash flows. SFAS No. 123 (R) requires the cash inflows resulting from tax deductions in excess of the compensation expense recognized for those stock options ("excess tax benefits") to be classified as financing cash inflows. As required by SFAS No. 123(R), Devon recognized $14 million of excess tax benefits as financing cash inflows for the nine months ended September 30, 2006.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109." Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This Interpretation is effective for fiscal years beginning after December 15, 2006. Devon is currently assessing the effect, if any, the adoption of Interpretation No. 48 will have on its financial statements and related disclosures.

In September 2006, the FASB issued 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. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. Devon is currently assessing the effect, if any, the adoption of Statement No. 157 will have on its financial statements and related disclosures.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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FASB Statements No. 87, 88, 106, and 132(R).” Statement No. 158 requires the recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. This requirement is effective for fiscal years ending after December 15, 2006 for employers with publicly-traded securities. Statement No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer’s fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This requirement is effective for fiscal years ending after December 15, 2008. Devon does not expect Statement No. 158 will have a material effect on its results of operations, financial condition, liquidity or compliance with debt covenants.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, “Considering the Effects of Prior Year Misstatements in Current Year Financial Statements.” SAB 108 provides guidance for quantifying and assessing the materiality of misstatements of financial statements, including uncorrected misstatements that were not material to prior years’ financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. Devon does not expect SAB 108 will have a material effect on its financial statements and related disclosures.

2. Comprehensive Income or Loss

Devon’s comprehensive income or loss information is included in the accompanying consolidated statements of stockholders’ equity and comprehensive income. A summary of accumulated other comprehensive income as of September 30, 2006 and 2005, and changes during each of the nine months then ended, is presented in the following table.

	Foreign Currency Translation Adjustments	Change in Fair Value of Financial Instruments	Minimum Pension Liability Adjustments	Unrealized Gain on Marketable Securities	Total
			(In millions)		
Balance as of December 31, 2005	$ 1,217	3	(18)	212	1,414
2006 activity	303	(1)	—	114	416
Deferred taxes	7	—	—	(41)	(34)
2006 activity, net of deferred taxes	310	(1)	—	73	382
Balance as of September 30, 2006	$ 1,527	2	(18)	285	1,796
Balance as of December 31, 2004	$ 1,055	(286)	(13)	174	930
2005 activity	215	177	—	173	565
Deferred taxes	(22)	(68)	—	(62)	(152)
2005 activity, net of deferred taxes	193	109	—	111	413
Balance as of September 30, 2005	$ 1,248	(177)	(13)	285	1,343

3. Supplemental Cash Flow Information

Cash payments for interest and income taxes in the first nine months of 2006 and 2005 are presented below:

	Nine Months Ended September 30, 2006	2005
	(In millions)	
Interest paid	$406	581
Income taxes	$690	885

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

4. Property and Equipment and Asset Retirement Obligations

Chief Acquisition

On June 29, 2006, Devon completed its acquisition of privately-owned Chief Holdings LLC ("Chief"). Devon paid $2.0 billion in cash and assumed approximately $0.2 billion of net liabilities in the transaction for a total purchase price of $2.2 billion. Devon funded the acquisition price, and the immediate retirement of $180 million of assumed debt, with $718 million of cash on hand and approximately $1.4 billion of borrowings issued under its commercial paper program. Devon estimates that the acquired properties include proved reserves of 598.2 billion cubic feet of natural gas equivalent and leasehold totaling 169,000 net acres located in the Barnett Shale area of Texas. Devon preliminarily allocated approximately $1.0 billion of the purchase price to proved reserves and approximately $1.2 billion to unproved properties.

Asset Retirement Obligation

The following is a summary of the changes in Devon's asset retirement obligation for the first nine months of 2006 and 2005.

	Nine Months Ended September 30,	
	2006	2005
	(In millions)	
Asset retirement obligation as of beginning of period	$ 668	739
Liabilities incurred	92	39
Liabilities settled	(41)	(25)
Liabilities assumed by others	—	(199)
Revision of estimated obligation	140	75
Accretion expense on discounted obligation	37	35
Foreign currency translation adjustment	13	9
Asset retirement obligation as of end of period	909	673
Less current portion	45	56
Asset retirement obligation, long-term	$ 864	617

5. Debt

New Credit Facility

In April 2006, Devon replaced its existing $1.5 billion five-year unsecured revolving credit facility with a $2.0 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). In June 2006, Devon amended its Senior Credit Facility to increase the aggregate commitment amount under the Senior Credit Facility from $2.0 billion to $2.5 billion. The amendment also added the right to increase the aggregate commitment further to $3.0 billion, under the same terms and conditions, should Devon deem any additional increase necessary.

The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million.

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, Devon has the

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

option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders.

Amounts borrowed under the Senior Credit Facility may, at Devon's election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $2.3 million that is payable quarterly in arrears.

As of September 30, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of September 30, 2006, net of $295 million of outstanding letters of credit and $1.4 billion of outstanding commercial paper, was approximately $766 million.

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, 2006, Devon was in compliance with such covenants and restrictions. Devon's debt-to-capitalization ratio at September 30, 2006, as calculated pursuant to the terms of the agreement, was 26.5%.

Commercial Paper

On June 28, 2006, Devon commenced issuing commercial paper under its program. Devon may borrow up to $2.0 billion under the commercial paper program. Any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between one to 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, London Interbank Offered Rate (LIBOR), or the money market rate as found in the commercial paper market. As of September 30, 2006, Devon had $1.4 billion of commercial paper outstanding at an average rate of 5.43%. The $1.4 billion of commercial paper is classified as short-term debt in the accompanying consolidated balance sheet.

6. Income Taxes

During the second quarter of 2006, the Canadian Federal and Alberta provincial governments enacted statutory rate reductions. As a result of these rate reductions, Devon 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 new tax in the second quarter of 2006, Devon recorded $39 million of deferred tax expense in such quarter.

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.

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

7. Stockholders' Equity

The following is a summary of the changes in Devon's common shares outstanding for the first nine months of 2006 and 2005.

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions)	
Shares outstanding, beginning of period	443	484
Exercise of stock options	2	5
Shares repurchased and retired	(4)	(45)
Grant of restricted stock awards	1	—
Shares outstanding, end of period	442	444

The shares repurchased in 2006 were repurchased at a cost of $253 million, or $59.61 per share. The shares repurchased in 2005 were repurchased at a cost of $2.1 billion, or $47.69 per share.

On August 3, 2005, Devon announced that its board of directors had authorized the repurchase of up to 50 million shares of our common stock. As of August 1, 2006, Devon had repurchased 6.5 million shares under this program for $387 million, or $59.80 per share. As a result of the Chief acquisition (see Note 4), this repurchase program has been suspended and will be reevaluated at a later date.

Share-Based Compensation Plans

As discussed in Note 1, on January 1, 2006, Devon changed its method of accounting for share-based compensation from the APB No. 25 intrinsic value accounting method to the fair value recognition provisions of SFAS No. 123(R). Currently, Devon's share-based compensation includes amounts related to grants of nonqualified and incentive stock options, restricted stock awards and restricted stock units.

The following table is a summary of the effects of share-based compensation included in Devon's accompanying statement of operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
		(In millions)		
Gross general and administrative expense	$22	7	60	20
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 5	—	16	—
Related income tax benefit	$ 6	2	16	7

Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions. The volatility of Devon's common stock is based on the historical volatility of the market price of Devon's common stock over a period of time equal to the expected term of the option and ending on the grant date. The dividend yield is based on Devon's historical and current yield in effect at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury yield for the expected term of the option at the date of grant. The expected term of the options is based on historical exercise and termination experience for various groups of employees and directors. Each group is determined based on the similarity of their historical exercise and termination behavior.

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Included in the following table is a summary of the grant-date fair values of stock options granted and the related assumptions. All such amounts represent the weighted-average amounts for each period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Grant-date fair value	$19.86	18.61	19.92	16.11
Volatility factor	30.8%	31.2%	31.7%	33.0%
Dividend yield	0.5%	0.6%	0.4%	0.6%
Risk-free interest rate	5.6%	4.2%	5.1%	4.0%
Expected term (in years)	4.0	4.0	4.4	4.4

Devon estimates the fair values of restricted stock awards and units as the closing price of Devon’s common stock on the grant date of the award or unit.

A summary of Devon’s outstanding stock options as of September 30, 2006, including changes during the nine months then ended, is presented below.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(In thousands)		(In Years)	(In millions)
Outstanding at December 31, 2005	16,732	$32.74		
Granted	181	$60.73		
Exercised	(2,025)	$25.92		
Forfeited	(327)	$49.43		
Outstanding at September 30, 2006	14,561	$33.66	4.1	$437
Vested and expected to vest at September 30, 2006	14,247	$33.20	4.1	$434
Exercisable at September 30, 2006	8,941	$25.05	3.9	$341

A summary of Devon’s unvested restricted stock awards as of September 30, 2006, including changes during the nine months then ended, is presented below.

	Restricted Stock Awards	Weighted Average Grant-Date Fair Value
	(In thousands)	
Unvested at December 31, 2005	3,187	$46.80
Granted	884	$56.39
Vested	(105)	$29.98
Forfeited	(130)	$47.18
Unvested at September 30, 2006	3,836	$49.46

The aggregate intrinsic value of options exercised and the aggregate fair value of restricted stock awards vested are summarized in the table below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Intrinsic value of stock options exercised	$38	53	78	129
Fair value of restricted stock awards vested	$ 1	1	9	6

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As of September 30, 2006, Devon's unrecognized compensation costs related to unvested stock options and restricted stock awards were $50 million and $152 million, respectively. Such costs are expected to be recognized over weighted-average periods of 1.7 years and 2.5 years, respectively.

8. Other Income

The components of other income include the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Interest and dividend income	$ 22	22	78	73
Net (loss) gain on sales of non-oil and gas property and equipment	—	(5)	5	145
Gain (loss) on derivative financial instruments	—	7	—	(48)
Other	5	3	2	9
Other income, net	$ 27	27	85	179

9. Retirement Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans ("Qualified Plans") and nonqualified plans ("Supplemental Plans"). The Qualified Plans provide retirement benefits for U.S. and Canadian employees meeting certain age and service requirements. The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. Devon also has defined benefit postretirement plans ("Postretirement Plans") which provide benefits for substantially all employees. The Postretirement Plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory.

Net Periodic Cost

The following table presents the plans' net periodic benefit cost for the three-month and nine-month periods ended September 30, 2006 and 2005.

	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,	
	2006	2005	2006	2005	2006	2005	2006	2005
	(In millions)							
Components of net periodic benefit cost:								
Service cost	$ 6	5	18	15	—	—	—	—
Interest cost	10	8	30	24	1	1	3	3
Expected return on plan assets	(11)	(9)	(33)	(27)	—	—	—	—
Recognized net actuarial loss	3	2	9	6	—	—	—	—
Net periodic benefit cost	$ 8	6	24	18	1	1	3	3

Employer Contributions

Devon previously disclosed in its financial statements for the year ended December 31, 2005, that it expected to contribute $7 million to the Qualified and Supplemental Plans in 2006 and $5 million to the

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Postretirement Plans in 2006. As of September 30, 2006, Devon has contributed $4 million to the Qualified and Supplemental Plans and $5 million to the Postretirement Plans.

10. 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.

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, 2006, Devon's consolidated balance sheet included $5 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 February 1, 2006, the Court entered a scheduling order in which trial is set for November 2007 if the suit continues to advance. 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 "DWRRA"). The intent of the DWRRA was to encourage deep water exploration in the Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. The DWRRA granted royalty relief, without regard to the market prices of oil or natural gas, with respect to leases issued between November 28, 1995 and November 28, 2000. However, in regulations promulgated by the Minerals Management Service (the "MMS") subsequent to the passage of the DWRRA, the MMS imposed price thresholds on certain of these deep water leases issued in 1996, 1997 and 2000, 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.

The MMS has issued an order to Devon and other oil and gas producers to pay royalties on production from these leases issued in 1996, 1997 and 2000 due to market prices exceeding the price thresholds in recent years. Devon and certain other oil and gas producers have filed Administrative Appeals with the MMS contesting the MMS' orders. In March 2006, one oil and gas producer filed suit in Federal court against the Department of Interior challenging the MMS' authority to suspend royalty relief on the subject leases. Subsequently, in June 2006, such producer announced that it and the Department of Interior had agreed to ask the court to postpone the entry of a scheduling order while the two parties undertake efforts to mediate the disagreement.

Devon does not believe that the MMS has the legal authority to suspend the royalty relief granted by the DWRRA. This is based in part on prior successful litigation against the Department of Interior and the MMS involving similar issues related to the DWRRA. However, Devon accrued approximately $14 million in the third quarter of 2006 for this issue. Such amount represents all of Devon's liability for prior royalties and related interest on the 1996, 1997 and 2000 leases.

Deep water leases issued in 1998 and 1999 did not include price thresholds. However, numerous government officials have recently called for the renegotiation of the leases issued in 1998 and 1999, with the renegotiated terms to include price thresholds. In June and July 2006, the MMS issued letters to Devon and other oil and gas producers who acquired leases issued in 1998 and 1999. In such letters, the MMS acknowledges that the 1998 and 1999 leases do not include price thresholds, but maintains that such omission was an error on its part and was not its intention. While the MMS confirmed that it will continue to honor the terms of these leases as issued, it noted the concerns being expressed by Congress and 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. Devon representatives met with MMS officials in the third quarter of 2006, but such meeting did not involve specific negotiations.

Devon is unable to determine its course of action until more information is received from the MMS. However, if Devon were to agree to renegotiate the terms of its 1998 and 1999 leases to include price threshold provisions, Devon would expect that such provisions would only be effective on a prospective basis. Devon understands from various published reports that although the MMS' renegotiations have to date involved applying the price threshold provisions on a prospective basis only, certain members of Congress believe that any lease renegotiations should include both retroactive and prospective applications of price thresholds. Language has been included in an appropriations bill that

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would prohibit companies from bidding on new leases if they have not paid prior royalties on properties obtained in 1998 and 1999 leases. If Devon were to renegotiate its leases under terms that include retroactive application of price thresholds, Devon estimates that it would owe approximately $94 million related to production prior to September 30, 2006.

Devon has not renegotiated its 1998 and 1999 leases with the MMS, nor has the MMS asserted a claim against Devon for any royalties from production of oil and gas related to the 1998 and 1999 leases. Accordingly, the ultimate amount of royalties, if any, to be paid by Devon for prior production of oil and gas related to the 1998 and 1999 leases is not determinable as of September 30, 2006 and, therefore, no amount has been accrued in the accompanying consolidated financial statements.

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 previous requests for information in this inquiry and plans to continue to work with the SEC in connection with its formal 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 included 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 primary insurers. Devon has not reached any settlement with the carriers insuring losses above this amount. Devon continues to have discussions with these insurers, and Devon's claims have not been denied. As of September 30, 2006, $135 million of the total proceeds of $467 million had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $332 million will be utilized as reimbursement of Devon's anticipated future repair costs. Such amount is recognized as liabilities in the accompanying September 30, 2006 balance sheet ($180 million in accrued expenses and other current liabilities and $152 million in long-term other liabilities). Should Devon's total policy recoveries, including the partial settlements already received 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, 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 losses under this new insurance arrangement through September 30, 2006.

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Other Matters

The Internal Revenue Service and other state and national government agencies audit Devon’s tax returns in the normal course of business. Typically, any findings resulting from such audits relate to the timing of recognition of revenues or expenses. On occasion, audit findings relate to costs treated as eligible deductions or revenues treated as nontaxable income. Devon has a process in place to identify and support the deductibility or nontaxable nature of such items prior to the filing of the tax returns, including review by external tax attorneys if deemed necessary.

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon’s knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Commitments

During 2006, Devon entered into two significant contracts to procure drilling rigs to be used in the deepwater Gulf of Mexico. Devon’s total commitment under the terms of these four-year contracts is approximately $1.1 billion. One rig is scheduled for delivery in mid-2007, and the other rig is scheduled for delivery in mid-2008.

11. 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)			
Unsuccessful exploratory reductions:				
Nigeria	$ —	—	85	85
Brazil	—	—	16	16
Ceiling test reductions:				
Egypt	31	18	31	18
Russia	20	10	20	10
Total	$ 51	28	152	129

Devon has committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, Devon determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, Devon recognized an $85 million impairment of its investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There is no tax benefit related to this impairment.

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 is no tax benefit related to this impairment. The two wells were unrelated to Devon’s Polvo development project in Brazil.

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The full cost method of accounting for oil and gas properties subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. The ceiling limitation is imposed separately for each country in which Devon has oil and gas properties. At December 31, 2005, Devon's net book value of oil and gas properties, less related deferred income taxes, was below the ceiling, resulting in an excess "cushion" for all countries. This excess "cushion" was $7.9 billion and $3.6 billion for Devon's U.S. and Canadian properties, respectively.

From December 31, 2005, to September 30, 2006, the NYMEX Henry Hub and AECO natural gas index prices each decreased approximately 60%. As a result, on September 30, 2006, the net book value, less related deferred income taxes, of Devon's U.S. and Canadian properties exceeded the ceiling by $331 million and $448 million, respectively. However, natural gas prices improved sufficiently subsequent to September 30, 2006, but before Devon's third quarter financial statements were released, to restore the U.S. and Canadian cushions to $4.8 billion and $1.6 billion, respectively. As a result, Devon was not required to record reductions of its oil and gas properties under the full cost method of accounting for oil and gas properties in the third quarter of 2006. Had Devon been required to record the reductions using September 30, 2006, prices, the U.S. and Canada reductions would have been $530 million and $634 million, respectively, offset by deferred income tax benefits of $199 million and $186 million, respectively.

As a result of unsuccessful exploratory activities in Egypt during 2005 and 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 $31 million reduction of the book value of its oil and gas properties in Egypt, offset by a $13 million deferred income tax benefit.

Also, as a result of a decline in projected future net cash flows, Devon's Russian properties exceeded the ceiling by $10 million. 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.

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12. 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, 2006:				
Current assets	$ 1,030	710	1,196	2,936
Property and equipment, net of accumulated depreciation, depletion and amortization	14,612	7,025	2,460	24,097
Goodwill	3,056	2,698	68	5,822
Other assets	1,310	36	31	1,377
Total assets	$ 20,008	10,469	3,755	34,232
Current liabilities	$ 2,924	551	351	3,826
Long-term debt	2,988	2,974	—	5,962
Asset retirement obligation, long-term	395	376	93	864
Other liabilities	707	10	21	738
Deferred income taxes	3,354	1,914	357	5,625
Stockholders' equity	9,640	4,644	2,933	17,217
Total liabilities and stockholders' equity	$ 20,008	10,469	3,755	34,232

	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2006:				
Revenues:				
Oil sales	$ 328	174	408	910
Gas sales	856	329	6	1,191
NGL sales	151	53	—	204
Marketing and midstream revenues	404	9	4	417
Total revenues	1,739	565	418	2,722
Expenses and other income, net:				
Lease operating expenses	207	141	34	382
Production taxes	58	1	33	92
Marketing and midstream operating costs and expenses	299	2	2	303
Depreciation, depletion and amortization of oil and gas properties	358	164	82	604
Depreciation and amortization of non-oil and gas properties	38	5	1	44
Accretion of asset retirement obligation	7	6	—	13
General and administrative expenses	80	24	—	104
Interest expense	56	56	—	112
Change in fair value of derivative financial instruments	22	—	—	22
Reduction of carrying value of oil and gas properties	—	—	51	51
Other (income) expense, net	6	—	(33)	(27)
Total expenses and other income, net	1,131	399	170	1,700
Earnings before income tax expense	608	166	248	1,022
Income tax expense (benefit):				
Current	119	23	89	231
Deferred	93	32	(39)	86
Total income tax expense	212	55	50	317
Net earnings	396	111	198	705
Preferred stock dividends	2	—	—	2
Net earnings applicable to common stockholders	$ 394	111	198	703
Capital expenditures	$ 931	326	145	1,402

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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2005:				
Revenues:				
Oil sales	$ 259	107	277	643
Gas sales	990	465	11	1,466
NGL sales	135	53	2	190
Marketing and midstream revenues	402	3	—	405
Total revenues	1,786	628	290	2,704
Expenses and other income, net:				
Lease operating expenses	174	117	28	319
Production taxes	65	1	15	81
Marketing and midstream operating costs and expenses	292	2	—	294
Depreciation, depletion and amortization of oil and gas properties	267	149	77	493
Depreciation and amortization of non-oil and gas properties	35	4	1	40
Accretion of asset retirement obligation	6	5	1	12
General and administrative expenses	60	14	(4)	70
Interest expense	49	115	—	164
Effects of changes in foreign currency exchange rates	—	(15)	—	(15)
Change in fair value of derivative financial instruments	122	12	—	134
Other income, net	(17)	(6)	(4)	(27)
Total expenses and other income, net	1,053	398	114	1,565
Earnings before income tax expense	733	230	176	1,139
Income tax expense (benefit):				
Current	126	11	66	203
Deferred	119	75	(2)	192
Total income tax expense	245	86	64	395
Net earnings	488	144	112	744
Preferred stock dividends	2	—	—	2
Net earnings applicable to common stockholders	$ 486	144	112	742
Capital expenditures	$ 516	415	91	1,022

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	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2006:				
Revenues:				
Oil sales	$ 956	463	1,063	2,482
Gas sales	2,577	1,122	26	3,725
NGL sales	414	159	—	573
Marketing and midstream revenues	1,237	24	15	1,276
Total revenues	5,184	1,768	1,104	8,056
Expenses and other income, net:				
Lease operating expenses	601	399	93	1,093
Production taxes	182	4	75	261
Marketing and midstream operating costs and expenses	917	7	6	930
Depreciation, depletion and amortization of oil and gas properties	943	484	240	1,667
Depreciation and amortization of non-oil and gas properties	113	13	3	129
Accretion of asset retirement obligation	19	16	2	37
General and administrative expenses	221	66	(3)	284
Interest expense	144	171	—	315
Effects of changes in foreign currency exchange rates	—	1	(2)	(1)
Change in fair value of derivative financial instruments	83	(2)	—	81
Reduction of carrying value of oil and gas properties	—	—	152	152
Other income, net	(27)	(12)	(46)	(85)
Total expenses and other income, net	3,196	1,147	520	4,863
Earnings before income tax expense (benefit)	1,988	621	584	3,193
Income tax expense (benefit):				
Current	385	111	237	733
Deferred	388	(121)	(71)	196
Total income tax expense (benefit)	773	(10)	166	929
Net earnings	1,215	631	418	2,264
Preferred stock dividends	7	—	—	7
Net earnings applicable to common stockholders	$ 1,208	631	418	2,257
Capital expenditures	$ 4,758	1,296	402	6,456

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	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2005:				
Revenues:				
Oil sales	$ 828	268	812	1,908
Gas sales	2,641	1,240	32	3,913
NGL sales	348	138	6	492
Marketing and midstream revenues	1,201	9	—	1,210
Total revenues	5,018	1,655	850	7,523
Expenses and other income, net:				
Lease operating expenses	538	370	97	1,005
Production taxes	189	5	40	234
Marketing and midstream operating costs and expenses	917	4	—	921
Depreciation, depletion and amortization of oil and gas properties	856	427	245	1,528
Depreciation and amortization of non-oil and gas properties	104	11	4	119
Accretion of asset retirement obligation	20	13	2	35
General and administrative expenses	177	41	(12)	206
Interest expense	180	248	—	428
Effects of changes in foreign currency exchange rates	—	(2)	(2)	(4)
Change in fair value of derivative financial instruments	158	10	—	168
Other income, net	(169)	(3)	(7)	(179)
Total expenses and other income, net	2,970	1,124	367	4,461
Earnings before income tax expense	2,048	531	483	3,062
Income tax expense (benefit):				
Current	588	50	194	832
Deferred	132	159	(21)	270
Total income tax expense	720	209	173	1,102
Net earnings	1,328	322	310	1,960
Preferred stock dividends	7	—	—	7
Net earnings applicable to common stockholders	$ 1,321	322	310	1,953
Capital expenditures	$ 1,551	1,377	181	3,109

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

The following discussion addresses material changes in results of operations for the three-month and nine-month periods ended September 30, 2006, compared to the three-month and nine-month periods ended September 30, 2005, and in financial condition since December 31, 2005. It is presumed that readers have read or have access to Devon's 2005 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

We continued to execute our strategy to increase value per share. On June 29, 2006, we completed our acquisition of privately-owned Chief Holdings LLC ("Chief"). We paid $2.0 billion in cash and assumed approximately $0.2 billion of net liabilities in the transaction. We funded the acquisition price, and the immediate retirement of $180 million of assumed debt, with $718 million of cash on hand and approximately $1.4 billion of borrowings issued under our commercial paper program. We estimate that the acquired properties include proved reserves of 598.2 billion cubic feet of natural gas equivalent and leasehold totaling 169,000 net acres located in the Barnett Shale area of Texas. We preliminarily allocated approximately $1.0 billion of the purchase price to proved reserves and approximately $1.2 billion to unproved properties. The Chief acquisition added five Bcf of additional production during the third quarter of 2006.

Our deepwater Gulf of Mexico exploration program has reached several important milestones, two in the third quarter of 2006, related to the lower Tertiary trend. To date, we have drilled four discovery wells in the lower Tertiary—Cascade in 2002, St. Malo in 2003, Jack in 2004 and Kaskida in the third quarter of 2006. Also in the third quarter of 2006, we announced the successful production test of the Jack #2 well in the lower Tertiary. We currently hold 273 blocks in the lower Tertiary and have identified 19 additional prospects to date. These achievements support our positive view of the lower Tertiary and demonstrate the growth potential of our high-impact exploration strategy on long-term production, reserves and value.

The following summarizes our performance for the three-months and nine-months ended 2006 compared to the three-months and nine-months ended 2005:

- Net earnings decreased 5% and increased 15% for the third quarter and first nine months of 2006, respectively
- Earnings per diluted share decreased 4% and increased 22% for the third quarter and first nine months of 2006, respectively
- Net cash provided by operating activities increased 34% to $4.9 billion for the first nine months of 2006
- Combined realized price for oil, gas and NGLs was flat for the third quarter compared to a 17% increase in the first nine months of 2006
- Marketing and midstream operating profit rose 2% and 20% for the third quarter and first nine months of 2006, respectively
- Production increased 1% for the third quarter and decreased 2% for the first nine months of 2006, excluding the effects of our 2005 sales of non-core properties
- Per unit production and operating expenses increased 18% and 19% for the third quarter and first nine months of 2006, respectively, due to cost inflation driven by commodity price increases and due to the weakened U.S. dollar compared to the Canadian dollar

- Deferred income taxes in the first nine months of 2006 include a $204 million net benefit due to the net effects of statutory rate reductions enacted by the Canadian Federal and Alberta provincial governments, partially offset by a new income-based tax enacted by the state of Texas
- Capital expenditures for oil and gas exploration and development activities, excluding the Chief acquisition price, were $3.9 billion for the first nine months of 2006
- We drilled 1,942 exploration and development wells during the first nine months of 2006, 98% of which were successful

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 Devon’s 2005 Annual Report on Form 10-K and in a Form 8-K dated November 1, 2006 that includes certain updated 2006 estimates.

Results of Operations

Oil, gas and NGL revenues were essentially flat for the third quarter of 2006 compared to the third quarter of 2005, and $467 million, or 7%, higher for the first nine months of 2006 compared to the first nine months of 2005. The three-month and nine-month comparisons of production and price changes are shown in the following tables.

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Change [2]	2006	2005	Change [2]
Production						
Oil (MMBbls)	14	15	-4%	41	50	-18%
Gas (Bcf)	212	205	+3%	604	628	-4%
NGLs (MMBbls)	5	6	-1%	17	18	-3%
Oil, Gas and NGLs (MMBoe) [1]	55	55	+1%	159	173	-8%
Average Prices						
Oil (Per Bbl)	$ 64.17	43.45	+48%	$ 60.48	38.10	+59%
Gas (Per Mcf)	5.62	7.13	-21%	6.17	6.23	-1%
NGLs (Per Bbl)	34.98	32.23	+9%	32.99	27.48	+20%
Oil, Gas and NGLs (Per Boe) [1]	41.65	41.81	—	42.62	36.55	+17%
Revenues ($ in millions)						
Oil	$ 910	643	+42%	$ 2,482	1,908	+30%
Gas	1,191	1,466	-19%	3,725	3,913	-5%
NGLs	204	190	+7%	573	492	+16%
Combined	$ 2,305	2,299	—	$ 6,780	6,313	+7%

	Domestic					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Change [2]	2006	2005	Change [2]
Production						
Oil (MMBbls)	5	6	-14%	15	20	-27%
Gas (Bcf)	149	136	+9%	415	421	-1%
NGLs (MMBbls)	4	4	+3%	14	14	+0%
Oil, Gas and NGLs (MMBoe) [1]	35	32	+5%	98	104	-6%
Average Prices						
Oil (Per Bbl)	$ 68.27	46.48	+47%	$ 64.30	40.85	+57%
Gas (Per Mcf)	5.73	7.25	-21%	6.21	6.27	-1%
NGLs (Per Bbl)	32.41	29.93	+8%	30.06	25.23	+19%
Oil, Gas and NGLs (Per Boe) [1]	38.86	42.14	-8%	40.34	36.61	+10%
Revenues ($ in millions)						
Oil	$ 328	259	+27%	$ 956	828	+15%
Gas	856	990	-14%	2,577	2,641	-2%
NGLs	151	135	+12%	414	348	+19%
Combined	$ 1,335	1,384	-4%	$ 3,947	3,817	+3%

	Canada					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Change [2]	2006	2005	Change [2]
Production						
Oil (MMBbls)	3	3	+1%	9	10	-4%
Gas (Bcf)	61	67	-9%	183	200	-9%
NGLs (MMBbls)	1	2	-11%	3	4	-7%
Oil, Gas and NGLs (MMBoe) [1]	14	16	-7%	43	47	-8%
Average Prices						
Oil (Per Bbl)	$ 54.85	33.89	+62%	$ 49.06	27.15	+81%
Gas (Per Mcf)	5.40	6.97	-22%	6.14	6.21	-1%
NGLs (Per Bbl)	45.23	40.86	+11%	44.20	35.76	+24%
Oil, Gas and NGLs (Per Boe) [1]	38.34	40.12	-4%	40.11	35.02	+15%
Revenues ($ in millions)						
Oil	$ 174	107	+63%	$ 463	268	+73%
Gas	329	465	-29%	1,122	1,240	-10%
NGLs	53	53	-1%	159	138	+15%
Combined	$ 556	625	-11%	$ 1,744	1,646	+6%

	International					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Change [2]	2006	2005	Change [2]
Production						
Oil (MMBbls)	6	6	+2%	17	20	-16%
Gas (Bcf)	2	2	-27%	6	7	-18%
NGLs (MMBbls)	—	—	N/M	—	—	N/M
Oil, Gas and NGLs (MMBoe) [1]	6	7	-1%	18	22	-17%
Average Prices						
Oil (Per Bbl)	$ 65.75	45.62	+44%	$ 63.53	40.72	+56%
Gas (Per Mcf)	3.60	4.65	-23%	4.20	4.18	+0%
NGLs (Per Bbl)	—	21.07	N/M	—	23.36	N/M
Oil, Gas and NGLs (Per Boe) [1]	63.72	44.20	+44%	61.27	39.60	+55%
Revenues ($ in millions)						
Oil	$ 408	277	+48%	$ 1,063	812	+31%
Gas	6	11	-44%	26	32	-17%
NGLs	—	2	N/M	—	6	N/M
Combined	$ 414	290	+43%	$ 1,089	850	+28%

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.

The 2005 average sales prices per unit of production shown in the preceding tables include the effect of our hedging activities which included commodity hedges that expired prior to the beginning of 2006. Included below is a comparison of our average sales prices with and without the effect of hedges for the three months and nine months ended September 30, 2005. The commodity hedges we assumed with our June 29, 2006 Chief acquisition have virtually no effect on our average sales prices for the three months and nine months ended September 30, 2006.

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
	With Hedges	Without Hedges	With Hedges	Without Hedges
Oil (per Bbl)	$43.45	56.51	38.10	47.83
Gas (per Mcf)	$ 7.13	7.25	6.23	6.32
NGLs (per Bbl)	$32.23	32.23	27.48	27.48
Oil, Gas and NGLs (per Boe)	$41.81	45.82	36.55	39.73

Oil Revenues

Oil revenues increased $267 million in the third quarter of 2006. Oil revenues increased $294 million due to a $20.72 per barrel increase in our realized average price of oil. A one million barrel decrease in production caused oil revenues to decrease $27 million. The decrease in 2006 is primarily related to domestic offshore production. Such decrease was partially offset by a one million barrel increase in production resulting from reaching partial payout of our carried interest in Azerbaijan.

Oil revenues increased $574 million in the first nine months of 2006. Oil revenues increased $919 million due to a $22.38 per barrel increase in our realized average price of oil. A nine million barrel decrease in production caused oil revenues to decrease $345 million. Production lost from the 2005 property divestitures caused a decrease of four million barrels. We also suspended certain domestic oil production in 2005 and 2006 due to the effects of Hurricanes Katrina, Rita, Dennis and Ivan. Compared to the first nine months of 2005, there were one million additional barrels of suspended production in the first nine months of 2006 due to these hurricanes. In addition, production decreased due to certain international properties for which we are receiving fewer volumes after recovering our costs under applicable production sharing contracts. These decreases were partially offset by a one million barrel increase in production resulting from reaching partial payout of our carried interest in Azerbaijan.

Gas Revenues

Gas revenues decreased $275 million in the third quarter of 2006. Gas revenues decreased $320 million due to a $1.51 per Mcf decrease in our realized average price of gas. An increase in production of seven Bcf caused gas revenues to increase $45 million. The June 2006 Chief acquisition accounted for five Bcf of increased production. Also, as compared to the third quarter of 2005, we restored three Bcf of production during 2006 related to the previously mentioned hurricanes. These increases were offset by a decrease resulting from natural production declines partially offset by new drilling and development in our U.S. onshore and offshore properties.

Gas revenues decreased $188 million in the first nine months of 2006. A decrease in production of 24 Bcf caused gas revenues to decrease $151 million. Gas revenues decreased $37 million due to a $0.06 per Mcf decrease in our realized average price of gas. Production lost from the 2005 property divestitures caused a decrease of 34 Bcf. Compared to the first nine months of 2005, there was an additional 14 Bcf of suspended production in the first nine months of 2006 due to the previously mentioned hurricanes. These decreases were partially offset by the June 2006 Chief acquisition, which accounted for five Bcf of increased production, and additional production from new drilling and development in our U.S. onshore and offshore properties partially offset by natural production declines.

NGL Revenues

NGL revenues increased $14 million in the third quarter of 2006. A $2.75 per barrel increase in our realized average NGL price in the third quarter of 2006 increased NGL revenues $16 million. A slight decrease in production caused NGL revenues to decrease by $2 million.

NGL revenues increased $81 million in the first nine months of 2006. A $5.51 per barrel increase in our realized average NGL price in the first nine months of 2006 increased NGL revenues $96 million. A slight decrease in production caused NGL revenues to decrease by $15 million.

Marketing and Midstream Revenues

Marketing and midstream revenues increased $12 million in the third quarter of 2006. Revenues increased $98 million primarily due to higher gas sales volumes related to the June 2006 Chief acquisition and higher third-party gas volumes. This increase was partially offset by lower gas prices, which caused revenues to decrease $86 million.

Marketing and midstream revenues increased $66 million in the first nine months of 2006. Revenues increased $60 million primarily due to higher gas sales volumes related to the June 2006 Chief acquisition and higher third-party gas volumes. The remainder of the increase was primarily due to higher NGL prices.

Oil, Gas and NGL Production and Operating Expenses

The components of oil, gas and NGL production and operating expenses are set forth in the following tables.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Change [1]	2006	2005	Change [1]
Expenses ($ in millions)						
Lease operating expenses	$ 382	319	+20%	$ 1,093	1,005	+9%
Production taxes	92	81	+13%	261	234	+12%
Total production and operating expenses	$ 474	400	+19%	$ 1,354	1,239	+9%
Expenses Per Boe						
Lease operating expenses	$ 6.91	5.80	+19%	$ 6.87	5.82	+18%
Production taxes	1.66	1.48	+12%	1.64	1.36	+21%
Total production and operating expenses	$ 8.57	7.28	+18%	$ 8.51	7.18	+19%

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

Lease operating expenses increased $63 million in the third quarter of 2006. The increase in lease operating expense was largely caused by higher commodity prices. With the overall increase in oil, gas and NGL prices during 2005 and the first half of 2006, more well workovers and repairs and maintenance costs were performed to either maintain or improve production volumes. Such costs also increased due to inflationary pressure driven by higher commodity prices. Commodity price increases also caused such operating costs as ad valorem taxes, power and fuel costs to rise. Also, to a lesser extent, lease operating expenses increased $12 million due to the June 2006 Chief acquisition and the partial payout of our carried interest in Azerbaijan in the third quarter of 2006. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $9 million increase in costs. Partially offsetting these increases was a decrease of $4 million in lease operating expenses related to properties that were sold in 2005.

Lease operating expenses increased $88 million in the first nine months of 2006. As discussed in the previous paragraph, the increase in lease operating expense for the first nine months of 2006 was largely caused by higher commodity prices. Changes in the Canadian-to-U.S. dollar exchange rate resulted in a $30 million increase in costs. Also, lease operating expenses increased $12 million due the June 2006 Chief acquisition and the partial payout of our carried interest in Azerbaijan in the third quarter of 2006. Partially offsetting these increases was a decrease of $80 million in lease operating expenses related to properties that were sold in 2005.

The increases described above were also the primary factors causing lease operating expenses per Boe to increase during the third quarter and first nine months of 2006. Although we divested properties that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar compared to the Canadian dollar had a greater effect on our per unit costs than the property divestitures.

Production taxes increased $11 million in the third quarter of 2006. The majority of our production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. During the third quarter of 2006, domestic oil, gas and NGL revenues decreased 4%, causing a slight decrease to production taxes. This was more than offset by the new Chinese “Special Petroleum Gain” tax based on higher oil prices. In the third quarter of 2006, we recorded $12 million from this new tax.

Production taxes increased $27 million in the first nine months of 2006. As discussed above, the majority of our production taxes are assessed on our onshore domestic properties. Therefore, the 3% increase in domestic oil, gas and NGL revenues in the first nine months of 2006 caused a slight increase to production taxes. Also, we recorded $21 million during the first nine months of 2006 related to the Chinese “Special Petroleum Gain” tax.

Marketing and Midstream Operating Costs and Expenses

Marketing and midstream operating costs and expenses increased $9 million in the third quarter of 2006. Expenses increased $86 million primarily due to increased gas volumes from the June 2006 Chief acquisition and higher third-party gas volumes. This was partially offset by a $77 million decrease resulting primarily from lower gas purchase prices.

Marketing and midstream operating costs and expenses increased $9 million in the first nine months of 2006. Expenses increased $40 million primarily due to increased gas volumes from the June 2006 Chief acquisition and higher third-party gas volumes. This was partially offset by a $31 million decrease resulting primarily from lower gas purchase prices.

Depreciation, Depletion and Amortization Expenses (“DD&A”)

DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment plus future development costs in those reserves (the “depletable base”). Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

Oil and gas property DD&A increased $111 million in the third quarter of 2006. DD&A increased $108 million due to an increase in the combined U.S., Canadian and international DD&A rate from $8.96 per Boe in the third quarter of 2005 to $10.91 per Boe in the third quarter of 2006. In addition, a 1% increase in the combined oil, gas and NGL production in the third quarter of 2006 caused oil and gas property DD&A to increase by $3 million. Contributing to the DD&A rate increase in 2006 were downward reserve revisions due to price. At September 30, 2006, the natural gas index prices most relevant to our production dropped to levels considerably less than related average prices for 2006. As a result, our September 30, 2006 reserves were reduced due to the loss in future net cash flow caused by the requirement to use the low September 30, 2006 prices. Subsequent to September 30, 2006, these gas prices have returned to higher levels that existed for much of the first nine months. If prices remain at these higher levels at December 31, 2006, the reserve revisions should be reversed, thereby benefiting the fourth quarter DD&A rate.

Other factors causing the rate increase include the June 2006 Chief acquisition, changes in the Canadian-to-U.S. dollar exchange rate and inflationary pressure on both the costs incurred in the prior twelve months as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. The DD&A rate also increased as a result of unproved costs which, in the third quarter of 2005, were not being amortized but were subsequently transferred to the depletable base as a result of drilling activities.

Oil and gas property DD&A increased $139 million in the first nine months of 2006. DD&A increased $260 million due to an increase in the combined U.S., Canadian and international DD&A rate from $8.85 per Boe in the first nine months of 2005 to $10.48 per Boe in the first nine months of 2006. This increase was partially offset by a 8% decrease in the combined oil, gas and NGL production in the first nine months of 2006 which caused oil and gas property DD&A to decrease by $121 million. The factors discussed above which contributed to the DD&A rate increase for the third quarter of 2006 were also the primary factors causing the rate increase for the first nine months of 2006.

General and Administrative Expenses ("G&A")

Devon's net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two components. One is the amount of G&A capitalized pursuant to the full cost method of accounting related to exploration and development activities. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Gross G&A	$ 196	140	544	420
Capitalized G&A	(66)	(44)	(185)	(135)
Reimbursed G&A	(26)	(26)	(75)	(79)
Net G&A	$ 104	70	284	206

Gross G&A increased $56 million in the third quarter of 2006 compared to the same period of 2005. Higher employee compensation and benefits costs caused gross G&A to increase $39 million. Of this increase, $8 million represented stock option expense recognized pursuant to our adoption of Statement of Financial Accounting Standard No. 123(R), *Share Based Payment*, in the first quarter of 2006, and $7 million represented an increase in restricted stock expense due to our grants subsequent to the third quarter of 2005. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $3 million increase in costs.

Gross G&A increased $124 million from the first nine months of 2006 compared to the same period of 2005. Higher employee compensation and benefits costs caused gross G&A to increase $86 million. Of this increase, $23 million represented stock option expense recognized pursuant to our adoption of Statement of Financial Accounting Standard No. 123(R), *Share Based Payment*, in the first quarter of 2006, and $16 million represented an increase in restricted stock expense due to our grants subsequent to the third quarter of 2005. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $10 million increase in costs.

The factors discussed above were also the primary factors causing the $22 million and $50 million increase in capitalized G&A in the third quarter and first nine months of 2006, respectively.

Interest Expense

The following schedule includes the components of interest expense for the third quarter and first nine months of 2006 and 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Interest based on debt outstanding	$ 126	126	359	391
Amortization of discounts/premiums	3	1	7	2
Facility and agency fees	1	1	2	2
Amortization of capitalized loan costs	—	—	1	6
Capitalized interest	(21)	(16)	(57)	(53)
Loss on extinguishment of debt	—	51	—	76
Other	3	1	3	4
Total interest expense	$ 112	164	315	428

Interest decreased $52 million from the third quarter of 2005 to the third quarter of 2006. The primary cause of the decrease was the $51 million premium incurred in the third quarter of 2005 for the early redemption of the $400 million 6.75% notes due March 15, 2011.

Interest decreased $113 million from the first nine months of 2005 to the same period for 2006. Interest decreased $32 million due to the net effects of 2005 and 2006 debt repayments partially offset by commercial paper borrowings during the third quarter of 2006. Interest also decreased $76 million due to the $51 million premium incurred for the early redemption of the $400 million 6.75% notes due March 15, 2011 and the $25 million loss on the early redemption of the zero coupon convertible senior debentures in 2005. In conjunction with the early redemption of the zero coupon debentures, we also expensed $5 million in remaining unamortized issuance costs in 2005.

Changes in Fair Value of Derivative Financial Instruments

The following schedule includes the components of the change in fair value of derivative financial instruments for the third quarter and first nine months of 2006 and 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In millions)			
Change in fair value of the option embedded in debentures exchangeable into shares of Chevron Corporation common stock	$ 22	90	83	119
Non-qualifying commodity hedges	—	45	—	45
Ineffectiveness of commodity hedges	—	1	—	6
Other	—	(2)	(2)	(2)
Total	$ 22	134	81	168

The fair value of the option embedded in debentures exchangeable into shares of Chevron Corporation common stock is driven primarily by the price of Chevron Corporation's common stock. As a result, increases or decreases in the price of such common stock generally will cause the fair value of this embedded option to increase or decrease in a like manner.

In the third quarter of 2005, we recognized a $45 million loss on certain oil derivative financial instruments that no longer qualified for hedge accounting because the hedged production exceeded actual and projected production under these contracts. The lower than expected production was caused primarily by hurricanes that affected offshore production in the Gulf of Mexico.

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)			
Unsuccessful exploratory reductions:				
Nigeria	$ —	—	85	85
Brazil	—	—	16	16
Ceiling test reductions:				
Egypt	31	18	31	18
Russia	20	10	20	10
Total	$ 51	28	152	129

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 is no tax benefit related to this impairment. The two wells were unrelated to our Polvo development project in Brazil.

We have committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, we determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, we recognized an $85 million impairment of our investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There is no tax benefit related to this impairment.

The full cost method of accounting for oil and gas properties subjects companies to quarterly calculations of a “ceiling,” or limitation on the amount of properties that can be capitalized on the balance sheet. The ceiling limitation is imposed separately for each country in which Devon has oil and gas properties.

As a result of unsuccessful exploratory activities in Egypt during 2005 and 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 $31 million reduction of the book value of its oil and gas properties in Egypt, offset by a $13 million deferred income tax benefit.

Also, as a result of a decline in projected future net cash flows, Devon’s Russian properties exceeded the ceiling by $10 million. 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.

Other Income, net

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

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions)			
Interest and dividend income	$ 22	22	78	73
Net (loss) gain on sales of non-oil and gas property and equipment	—	(5)	5	145
Gain (loss) on derivative financial instruments	—	7	—	(48)
Other	5	3	2	9
Other income, net	$ 27	27	85	179

The net gain on sales of non-oil and gas property and equipment in the first nine months of 2005 related to the sale of certain midstream assets in January 2005.

The loss on derivative financial instruments in the first nine months of 2005 related to hedges that no longer qualified for hedge accounting and were settled prior to the end of their original term. These commodity hedges related to 5,000 barrels per day of U.S. oil production and 3,000 barrels per day of Canadian oil production from properties sold as part of our property divestiture program.

Income Taxes

During interim periods, income tax expense is based on the estimated effective income tax rate that is expected for the entire fiscal year. The estimated effective tax rate was 31% in the third quarter of 2006 and 35% in the third quarter of 2005. The estimated effective tax rate was 29% in the first nine months of 2006 and 36% in the first nine months of 2005.

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. Excluding the effects of the statutory tax rate changes, the effect of the Brazil net operating loss carryforward and the effects of the oil and gas property impairments with no related tax benefits which were previously discussed, the effective rates were 33% for the third quarter of 2006 and 35% for the first nine months of 2006.

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, 2006	2005
	(In millions)	
Cash provided by (used in):		
Operating activities	$ 4,882	3,652
Investing activities	(5,554)	(597)
Financing activities	238	(3,145)
Effect of exchange rate changes	24	33
Net decrease in cash and cash equivalents	$ (410)	(57)
Cash and cash equivalents at end of period	$ 1,196	1,095
Short-term investments at end of period	$ 124	791

Cash Flows from Operating Activities

Net cash provided by operating activities ("operating cash flow") continued to be a primary source of capital and liquidity in the first nine months of 2006. The increase in operating cash flow in the first nine months of 2006 was primarily caused by the increase in net earnings as discussed in the "Results of Operations" section of this report. In addition, the 2006 operating cash flow includes $467 million of proceeds received in the third quarter as a full settlement of the amount due from our primary insurers related to hurricane business interruption claims.

Cash Flows from Investing Activities

Capital Expenditures. Cash used for capital expenditures in the first nine months of 2006 was $6.1 billion. This total includes $5.8 billion for the acquisition, drilling or development of oil and gas properties, including $2.0 billion related to the acquisition of the Chief properties. These 2006 amounts compare to cash used for capital expenditures of $2.9 billion in the first nine months of 2005 which included $2.8 billion for the acquisition, drilling or development of oil and gas properties. The higher capital expenditures in 2006 result primarily from inflationary pressure driven by higher commodity prices and additional drilling for our U.S. onshore, U.S. offshore and Canada operations.

Proceeds from the Sale of Property and Equipment. We generated sale proceeds of $36 million and $2.2 billion in the first nine months of 2006 and 2005, respectively. The decrease in proceeds in 2006 was largely due to our 2005 divesture program in which we sold non-core oil and gas properties as well as non-core midstream assets.

Cash Flows from Financing Activities

Debt Borrowings and Repayments. During the first nine months of 2006, we issued net commercial paper borrowings of $1.4 billion to fund a portion of the Chief acquisition price and the repayment of $180 million of debt acquired in the Chief acquisition. Also, during the first nine months of 2006, we retired the $500 million 2.75% notes and the $178 million ($200 million Canadian) 6.55% debt on their scheduled maturity dates.

During the first nine months of 2005, we paid $1.0 billion to redeem the zero coupon convertible debentures, the $400 million 6.75% notes due in March 2011 before their scheduled maturity, the $125 million 7.625% notes and the $143 million ($175 million Canadian) 7.25% senior notes upon their maturities in July 2005.

Stock Repurchases. During the first nine months of 2006, we repurchased 4.2 million shares at a cost of $253 million. This compares to the repurchase of 44.6 million shares for $2.1 billion in the first nine months of 2005.

Issuance of Common Stock. We received proceeds of $53 million and $117 million from shares issued from the exercise of stock options in the first nine months of 2006 and 2005, respectively.

Dividends. Devon's common stock dividends were $148 million and $103 million in the first nine months of 2006 and 2005, respectively. We also paid $7 million of preferred stock dividends in 2006 and 2005. The increase in common stock dividends from 2005 to 2006 was primarily related to a 50% increase in the quarterly dividend rate which was partially offset by a decrease in the number of shares outstanding. Effective with the first quarter 2006 dividend payment, Devon increased its quarterly dividend rate from $0.075 per share to $0.1125 per share. The decrease in shares outstanding was primarily related to share repurchases partially offset by shares issued for stock option exercises.

Liquidity

At September 30, 2006, our unrestricted cash and cash equivalents and short-term investments totaled $1.3 billion. During the first nine months of 2006 and 2005, such balances decreased $966 million and increased $233 million, respectively. The decrease in 2006 was primarily driven by the use of cash on hand to fund a portion of the Chief acquisition price and repay scheduled debt maturities.

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain a revolving line 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 the issuance of equity securities and long-term debt. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures and other contractual commitments.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. We expect operating cash flow to continue to be our primary source of liquidity.

Credit Lines

Another source of liquidity is our $2.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility also includes the right to increase the aggregate commitment further to $3.0 billion should we deem any additional increase necessary.

The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million.

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, we have the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders.

Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. We may also elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $2.3 million that is payable quarterly in arrears.

As of September 30, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of September 30, 2006, net of $295 million of outstanding letters of credit and $1.4 billion of outstanding commercial paper, was approximately $766 million.

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 of no more than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. Per the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. As of September 30, 2006, Devon's ratio as calculated pursuant to this covenant was 26.5%.

Our access to funds from the Senior Credit Facility is not restricted under any "material adverse effect" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While our Senior Credit Facility includes covenants that require Devon to report a condition or event having a material adverse effect on Devon, the obligation of the banks to fund the Senior Credit Facility is not conditioned on the absence of a material adverse effect.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $2.0 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days. As of September 30, 2006, we had approximately $1.4 billion of outstanding commercial paper which was issued to fund a portion of the Chief acquisition which closed on June 29, 2006.

Common Stock Repurchase Program

On August 3, 2005, we announced that our board of directors had authorized the repurchase of up to 50 million shares of our common stock. As of November 3, 2006, we had repurchased 6.5 million shares under this program for $387 million, or $59.80 per share. As a result of the Chief acquisition, this repurchase program has been suspended and will be reevaluated at a later date.

Contractual Obligations

During 2006, we entered into two significant contracts to procure drilling rigs to be used in the deepwater Gulf of Mexico. Our total commitment under the terms of these four-year contracts is approximately $1.1 billion. One rig is scheduled for delivery in mid-2007, and the other rig is scheduled for delivery in mid-2008.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109." Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This Interpretation is effective for fiscal years beginning after December 15, 2006. We are currently assessing the effect, if any, the adoption of Interpretation No. 48 will have on our financial statements and related disclosures.

In September 2006, the FASB issued 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. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the effect, if any, the adoption of Statement No. 157 will have on our financial statements and related disclosures.

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 recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. This requirement is effective for fiscal years ending after December 15, 2006 for employers with publicly-traded securities. Statement No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer's fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This requirement is effective for fiscal years ending after December 15, 2008. We do not expect Statement No. 158 will have a material effect on our results of operations, financial condition, liquidity or compliance with debt covenants.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements in Current Year Financial Statements." SAB 108 provides guidance for quantifying and assessing the materiality of misstatements of financial statements, including uncorrected misstatements that were not material to prior years' financial statements. SAB 108 is effective for fiscal years ending after November 15, 2006. We do not expect SAB 108 will have a material effect on our financial statements and related disclosures.

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 2005 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 Exchange Act of 1934) were effective as of September 30, 2006 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 2006 that has materially affected, or is reasonably likely to materially affect, Devon's internal control over financial reporting.

Part II. Other Information

Item 1. *Legal Proceedings*

There have been no material changes to the information included in Item 3. "Legal Proceedings" in our 2005 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 2005 Annual Report on Form 10-K.

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

The following table sets forth information with respect to repurchases by Devon of its shares of common stock during the third quarter of 2006.

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	—	$—	—	43,533,001
August	—	$—	—	43,533,001
September	—	$—	—	43,533,001
Total	—	$—	—	

(1) On August 3, 2005, Devon announced that its board of directors had authorized the repurchase of up to 50 million shares of its common stock. This stock repurchase program has been suspended and will be reevaluated at a later date.

Item 3. *Defaults Upon Senior Securities*

None

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

None

Item 5. *Other Information*

None

Item 6. *Exhibits*

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

Exhibit Number	Description
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Brian J. Jennings, Chief Financial 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 Brian J. Jennings, Chief Financial 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 2, 2006

/s/ Danny J. Heatly

Danny J. Heatly
Vice President – Accounting and Chief Accounting Officer

INDEX TO EXHIBITS

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Exhibit 31.1

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, J. Larry Nichols, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2006

/s/ J. Larry Nichols
J. Larry Nichols
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Brian J. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 1, 2006

/s/ Brian J. Jennings
Brian J. Jennings
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation (“Devon”) on Form 10-Q for the period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, J. Larry Nichols, Chief Executive Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ J. Larry Nichols

J. Larry Nichols
Chief Executive Officer
November 1, 2006

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation ("Devon") on Form 10-Q for the period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian J. Jennings, Chief Financial Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ Brian J. Jennings

Brian J. Jennings
Chief Financial Officer
November 1, 2006