BURLINGTON RESOURCES INC
Form 10-Q
November 02, 2005

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

FORM 10-Q

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

For the quarterly period ended September 30, 2005

OR

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

Commission File Number 1-9971

BURLINGTON RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	91-1413284 (I.R.S. Employer Identification Number)
717 Texas Ave., Suite 2100, Houston, Texas (Address of principal executive offices)	77002 (Zip Code)
Registrant's telephone number, including area code	(713) 624-9000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes þ No o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding
Common Stock, par value $.01 per share, as of September 30, 2005	378,037,355

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PART I - FINANCIAL INFORMATION

ITEM 1. Financial Statements

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF INCOME
(UNAUDITED)

	Third Quarter 2005	Third Quarter 2004	Nine Months 2005	Nine Months 2004
	(In Millions, Except per Share Amounts)			
Revenues	$ 1,953	$ 1,419	$ 5,215	$ 4,060
Costs and Other Income - Net				
Taxes Other than Income Taxes	94	67	250	188
Transportation Expense	127	112	364	329
Operating Costs	176	152	490	426
Depreciation, Depletion and Amortization	325	284	975	831
Exploration Costs	65	55	183	177
Administrative	76	54	176	153
Interest Expense	70	71	210	211
(Gain)/Loss on Disposal of Assets	(117)	-	(117)	10
Other Expense (Income) - Net	18	(5)	21	19
Total Costs and Other Income - Net	834	790	2,552	2,344
Income Before Income Taxes	1,119	629	2,663	1,716
Income Tax Expense	371	235	907	589
Net Income	$ 748	$ 394	$ 1,756	$ 1,127
Basic Earnings per Common Share	$ 1.98	$ 1.00	$ 4.60	$ 2.87
Diluted Earnings per Common Share	$ 1.96	$ 1.00	$ 4.56	$ 2.84

See accompanying Notes to Consolidated Financial Statements.

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BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET
(UNAUDITED)

	September 30, 2005	December 31, 2004
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 2,816	$ 2,179
Accounts Receivable	1,292	994
Inventories	159	124
Other Current Assets	309	158
	4,576	3,455
Oil & Gas Properties (Successful Efforts Method)	19,939	17,943
Other Properties	1,616	1,544
	21,555	19,487
Accumulated Depreciation, Depletion and Amortization	9,605	8,454
Properties - Net	11,950	11,033
Goodwill	1,093	1,054
Other Assets	239	202
Total Assets	$ 17,858	$ 15,744
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 1,274	$ 1,182
Taxes Payable	303	216
Accrued Interest	56	61
Dividends Payable	38	33
Deferred Income Taxes	-	48
Commodity Hedging Contracts and Other Derivatives	433	27
Other Current Liabilities	12	32
	2,116	1,599
Long-term Debt	3,893	3,887
Deferred Income Taxes	2,861	2,396
Other Liabilities and Deferred Credits	957	851
Commitments and Contingencies (Note 5)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $01 Per Share		
(Authorized 75,000,000 Shares; No Shares Issued)	-	-
Common Stock, Par Value $01 Per Share		
(Authorized 650,000,000 Shares; Issued 482,376,870 Shares)	5	5
Paid-in Capital	3,996	3,973
Retained Earnings	5,816	4,163

Deferred Compensation - Restricted Stock		(19)		(14)
Accumulated Other Comprehensive Income		1,057		1,092
Cost of Treasury Stock				
(104,339,515 and 94,435,401 Shares for 2005 and 2004, respectively)		(2,824)		(2,208)
Stockholders' Equity		8,031		7,011
Total Liabilities and Stockholders' Equity	$	17,858	$	15,744

See accompanying Notes to Consolidated Financial Statements.

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BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
(UNAUDITED)

	Nine Months 2005 (In Millions)	Nine Months 2004 (In Millions)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,756	$ 1,127
Adjustments to Reconcile Net Income to Net Cash		
Provided By Operating Activities		
Depreciation, Depletion and Amortization	975	831
Deferred Income Taxes	342	353
Exploration Costs	183	177
(Gain)/Loss on Disposal of Assets	(117)	10
Changes in Derivative Fair Values	(4)	(2)
Working Capital Changes		
Accounts Receivable	(282)	(258)
Inventories	(30)	(30)
Other Current Assets	(27)	(25)
Accounts Payable	69	168
Taxes Payable	106	127
Accrued Interest	(5)	2
Other Current Liabilities	(19)	7
Changes in Other Assets and Liabilities	16	(13)
Net Cash Provided By Operating Activities	2,963	2,474
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Properties	(1,833)	(1,200)
Proceeds from Sales and Other	149	(25)
Net Cash Used In Investing Activities	(1,684)	(1,225)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from Long-term Debt	-	41
Reduction in Long-term Debt	(1)	(2)
Dividends Paid	(98)	(89)
Common Stock Purchases	(691)	(342)
Common Stock Issuances	58	139
Net Cash Used In Financing Activities	(732)	(253)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	90	37

Increase in Cash and Cash Equivalents		637		1,033
Cash and Cash Equivalents				
Beginning of Year		2,179		757
End of Period	$	2,816	$	1,790

See accompanying Notes to Consolidated Financial Statements.

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BURLINGTON RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. BASIS OF PRESENTATION

The 2004 Annual Report on Form 10-K (“Form 10-K”) of Burlington Resources Inc. (the “Company”) includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Quarterly Report on Form 10-Q (“Quarterly Report”). The financial statements for the periods presented herein are unaudited and do not contain all information required by generally accepted accounting principles to be included in a full set of financial statements. In the opinion of management, all material adjustments necessary to present fairly the results of operations have been included. All such adjustments are of a normal, recurring nature. The results of operations for any interim period are not necessarily indicative of the results of operations for the entire year. The consolidated financial statements include certain reclassifications that were made to conform to current period presentation.

Basic earnings per common share (“EPS”) is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. The weighted average number of common shares outstanding for computing basic EPS was 378 million and 392 million for the third quarter of 2005 and 2004, respectively, and 382 million and 393 million for the first nine months of 2005 and 2004, respectively. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The weighted average number of common shares outstanding for computing diluted EPS, including dilutive stock options, was 381 million and 395 million for the third quarter of 2005 and 2004, respectively, and 385 million and 396 million for the first nine months of 2005 and 2004, respectively.

For the quarter ended September 30, 2005 and 2004, all shares attributable to outstanding options were dilutive. For the nine months ended September 30, 2005 and 2004, approximately 3 thousand and zero shares, respectively, attributable to the potential exercise of outstanding options were excluded from the calculation of diluted EPS because the effect was antidilutive. The Company has no convertible securities affecting EPS, therefore, no adjustments related to convertible securities were made to reported net income in the computation of EPS.

2. STOCK-BASED COMPENSATION

The Company uses the intrinsic value based method of accounting for stock-based compensation, as prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Under this method, the Company records no compensation expense for stock options granted when the exercise price for options granted is equal to the fair market value of the Company's Common Stock on the date of the grant.

The following table illustrates the effect on net income and EPS if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards (“SFAS”) No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, to stock-based employee compensation. The fair value of stock options included in the pro forma amounts is not necessarily indicative of future effects on net income and EPS.

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	Third Quarter 2005	Third Quarter 2004	Nine Months 2005	Nine Months 2004
	(In Millions, except per Share Amounts)			
Net income as reported	$ 748	$ 394	$ 1,756	$ 1,127
Less: Pro forma stock-based employee compensation cost, after tax	(1)	(3)	(4)	(9)
Net income - pro forma	$ 747	$ 391	$ 1,752	$ 1,118
Basic EPS - as reported	$ 1.98	$ 1.00	$ 4.60	$ 2.87
Basic EPS - pro forma	1.98	1.00	4.59	2.84
Diluted EPS - as reported	1.96	1.00	4.56	2.84
Diluted EPS - pro forma	$ 1.96	$ 0.99	$ 4.55	$ 2.82

3. COMPREHENSIVE INCOME

	Nine Months 2005		Nine Months 2004	
	(In Millions)			
Accumulated other comprehensive income - beginning of period		$ 1,092		$ 655
Net income	$ 1,756		$ 1,127	
Other comprehensive income (loss) - net of tax				
Hedging activities				
Current period changes in fair value of settled contracts	(44)		(1)	
Reclassification adjustments for settled contracts	25		14	
Changes in fair value of outstanding hedging positions	(274)		(44)	
Hedging activities	(293)		(31)	
Foreign currency translation				
Foreign currency translation adjustments	258		134	
Total other comprehensive income (loss)	(35)	(35)	103	103
Comprehensive income	$ 1,721		$ 1,230	
Accumulated other comprehensive income - end of period		$ 1,057		$ 758

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4. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Company uses derivative instruments to manage risks associated with natural gas and crude oil price volatility as well as interest rates. Derivative instruments that meet the hedge criteria in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, are designated as either cash-flow hedges or fair-value hedges. Derivative instruments designated as cash-flow hedges are used by the Company to mitigate the risk of variability in cash flows from natural gas and crude oil sales due to changes in market prices. Fair-value hedges are used by the Company to hedge or offset the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment. Derivative instruments that do not meet the hedge criteria in SFAS No. 133 are not designated as hedges.

As of September 30, 2005, the Company had the following derivative instruments outstanding with average underlying prices that represent hedged prices of commodities at various market locations.

			Notional Amount		Average	Fair Value Asset (Liability)
Settlement Period	Derivative Instrument	Hedge Strategy	Gas (MMBTU)	Oil (Barrels)	Underlying Prices	(In Millions)
2005	Swap	Cash flow	2,524,647		$ 6.89	$ (9)
	Swap	Not designated	1,550,000		(0.11)	5
	Purchased put	Cash Flow	41,643,802		6.10	-
	Written call	Cash flow	41,643,802		7.86	(182)
	Purchased put	Cash flow		1,840,000	44.16	-
	Written call	Cash flow		1,840,000	56.63	(20)
	Swap	Fair value	303,800		7.15	1
	N/A	Fair value (obligation)	303,800		6.96	(1)
2006	Swap	Cash flow	5,844,500		7.76	(21)
	Swap	Fair value	295,000		11.47	-
	N/A	Fair value (obligation)	295,000		11.09	(1)
	Purchased put	Cash flow	60,796,657		7.72	20
	Written call	Cash flow	60,796,657		9.83	(202)
	Purchased put	Cash flow		3,795,000	51.81	7
	Written call	Cash flow		3,795,000	66.41	(30)
2007	Swap	Cash flow	1,013,000		$ 3.83	(5)
						$(438)

As of September 30, 2005, the Company had the following derivative instruments outstanding related to interest rate swaps.

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount (In Millions)	Average Underlying Rate	Average Floating Rate	Fair Value Liability (In Millions)
2005	Interest rate swap	Fair value	$ 50	5.6%	LIBOR+3.36%	$ -
2006	Interest rate swap	Fair value	$ 50	5.6%	LIBOR+3.36%	(1)
						$ (1)

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Based on commodity prices as of September 30, 2005, the Company expects to reclassify losses of $428 million ($265million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At September 30, 2005, the Company had derivative assets of $7 million and derivative liabilities of $446 million of which $7 million and $13 million are included in Other Current Assets and Other Liabilities and Deferred Credits, respectively, on the Consolidated Balance Sheet.

The derivative assets and liabilities related to commodities represent the difference between hedged prices and market prices on hedged volumes of the commodities as of September 30, 2005. Hedging activities related to cash settlements on commodities decreased revenues $48 million and $9 million in the third quarter of 2005 and 2004, respectively. Hedging activities related to cash settlements on commodities decreased revenues $41 million and $23 million in the first nine months of 2005 and 2004, respectively.

Gains and losses related to ineffectiveness and derivative instruments not designated as hedging instruments are included in revenues. Losses of $318 thousand and $3 million related to ineffectiveness of cash-flow and fair-value hedges were recorded during the third quarter and first nine months of 2005, respectively. Gains of $1 million and $2 million related to ineffectiveness of cash-flow and fair-value hedges were recorded during the third quarter and first nine months of 2004, respectively. Gains of $4 million and $3 million related to derivative instruments not designated as hedging instruments were recorded during the third quarter and first nine months of 2005, respectively, compared to de minimis amounts during the same periods of 2004.

5. COMMITMENTS AND CONTINGENCIES

The Company and numerous other oil and gas companies have been named as defendants in various lawsuits alleging violations of the civil False Claims Act. These lawsuits were consolidated during 1999 and 2000 for pre-trial proceedings by the United States Judicial Panel on Multidistrict Litigation in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming (“MDL-1293”). The plaintiffs contend that defendants underpaid royalties on natural gas and NGLs produced on federal and Indian lands through the use of below-market prices, improper deductions, improper measurement techniques and transactions with affiliated companies during the period of 1985 to the present. Plaintiffs allege that the royalties paid by defendants were lower than the royalties required to be paid under federal regulations and that the forms filed by defendants with the Minerals Management Service (“MMS”) reporting these royalty payments were false, thereby violating the civil False Claims Act. The United States has intervened in certain of the MDL-1293 cases as to some of the defendants, including the Company. The plaintiffs and the intervenor have not specified in their pleadings the amount of damages they seek from the Company. On June 10, 2005, in the case of Amoco v. Watson, the United States Court of Appeals for the District of Columbia issued an opinion in favor of the MMS regarding a producer's obligation to place coal seam gas in "marketable condition" at no cost to the government when calculating federal royalty payments. Since some of the intervenor's claims relate to the Company's coal seam production in the San Juan Basin and the deductions utilized by the Company in calculating royalty payments on such production, the Company is currently analyzing the potential impact of the Amoco ruling on the intervenor's claims and the Company's defenses in these proceedings.

Various administrative proceedings are also pending before the MMS of the United States Department of the Interior with respect to the valuation of natural gas produced by the Company on federal and Indian lands. In general, these proceedings stem from regular MMS audits of the Company’s royalty payments over various periods of time and involve the interpretation of the relevant federal regulations. Most of these proceedings involve production volumes and royalties that are the subject of Natural Gas Royalties Qui Tam Litigation.

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Based on the Company's present understanding of the various governmental and civil False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. The Company is also exploring the possibility of a settlement of these claims. Although there has been no formal demand for damages, the Company currently estimates, based on its communications with the intervenor, that the amount of underpaid royalties on onshore production claimed by the intervenor in these proceedings is approximately $76 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could be subject to double damages, civil monetary penalties and other sanctions, including a temporary suspension from bidding on and entering into future federal mineral leases and other federal contracts for a defined period of time. As an alternative to monetary penalties under the False Claims Act, the intervenor has informed the Company that it may seek the recovery of interest payments of approximately $95 million. The Company has established a reserve to provide for this potential liability based upon management's evaluation of this matter.

The Company has also been named as a defendant in the lawsuit styled UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al, No. 98-854, filed in 1995 in the District Court in The Hague, the Netherlands and currently pending in the Supreme Court in The Hague. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.8 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeals in The Hague issued an interim judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. After receiving additional evidence from the parties, the Court of Appeals subsequently issued a ruling in favor of defendants. In an interim judgment issued on December 18, 2003, the Court of Appeals found that defendants should not have assumed that they were extracting oil from the Q-1 Block, that Unocal was not entitled to compensation for any production occurring prior to 1992 and that damages, if any, would be limited to the proceeds Unocal would have received for oil extracted from the Q-1 Block, less the costs Unocal would have incurred to produce the oil from an existing well in the L16a Block. The Court of Appeals ordered that further evidence be presented to a court appointed expert to determine whether any damages had been suffered by Unocal. Based on the information known to date, the Company believes that Unocal suffered no damages in excess of the costs of production. On October 14, 2005, the Supreme Court in The Hague issued a ruling denying all appeals and affirming the ruling by the Court of Appeals. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. The Company has not established a reserve for this matter since it currently does not believe that an unfavorable outcome is probable.

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The Company and its former affiliate, El Paso Natural Gas Company, have also been named as defendants in two class action lawsuits styled Bank of America, et al. v. El Paso Natural Gas Company, et al., Case No. CJ-97-68, and Deane W. Moore, et al. v. Burlington Northern, Inc., et. al., Case No. CJ-97-132, each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. Plaintiffs contend that defendants underpaid royalties from 1982 to the present on natural gas produced from specified wells in Oklahoma through the use of below-market prices, improper deductions and transactions with affiliated companies and in other instances failed to pay or delayed in the payment of royalties on certain gas sold from these wells. The plaintiffs seek an accounting and damages for alleged royalty underpayments, plus interest from the time such amounts were allegedly due. Plaintiffs additionally seek the recovery of punitive damages. The plaintiffs have not specified in their pleadings the amount of damages they seek from the Company. However, through pre-trial discovery, plaintiffs have provided defendants with alternative theories of recovery claiming monetary damages of up to $42 million in principal, plus $311 million in interest, and unspecified punitive damages and attorney’s fees. The Company believes it has substantial defenses to these claims and is vigorously asserting such defenses. The Company and El Paso Natural Gas Company have asserted contractual claims for indemnity against each other. The court has certified the plaintiff classes of royalty and overriding royalty interest owners. The trial of this matter commenced on October 10, 2005. The Company has established a reserve to provide for this potential liability based upon management’s evaluation of this matter.

The Company received notice on October 19, 2004 from the United States Department of Justice that it may be one of many potentially responsible parties under the Comprehensive Environmental Response, Compensation and Liability Act, as amended, with respect to the remediation of a site known as the Castex Systems, Inc. Oil Field Waste Disposal Site in Jefferson Davis Parish near Jennings, Louisiana. According to the Department of Justice, the remediation of the site has been completed under the supervision of the United States Environmental Protection Agency for a total cost of approximately $3 million. The Company has been informed that it may have contributed up to two and one-half percent (2.5%) of the liquid oil field waste and twelve percent (12%) of the solid oil field waste identified at the site. The Company is currently investigating this matter to determine if it is liable for any portion of the remediation costs.

In addition to the foregoing, the Company and its subsidiaries are named defendants in numerous other lawsuits and named parties in numerous governmental and other proceedings arising in the ordinary course of business, including: claims for personal injury and property damage, claims challenging oil and gas royalty, ad valorem and severance tax payments, claims related to joint interest billings under oil and gas operating agreements, claims alleging mismeasurement of volumes and wrongful analysis of heating content of natural gas and other claims in the nature of contract, regulatory or employment disputes. None of the governmental proceedings involve foreign governments.

While the ultimate outcome and impact on the Company cannot be predicted with certainty and could prove to be greater than management’s current assessments, management believes that the resolution of these legal proceedings and environmental matters through settlement or adverse judgment will not have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

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At September 30, 2005, the Company's Consolidated Balance Sheet included reserves for legal proceedings of $118 million and environmental matters of $20 million. The accrual of reserves for legal and environmental matters is included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional loss, the amount of which is not currently estimable, in excess of the amounts currently accrued with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings and environmental matters will exceed current accruals by an amount that would have a material adverse effect on the consolidated financial position or results of operations of the Company, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

6. LONG-TERM DEBT

The fair value of the Company's long-term debt at September 30, 2005 and December 31, 2004 was approximately $4,467 million and $4,528 million, respectively, based on quoted market prices.

7. SEGMENT AND GEOGRAPHIC INFORMATION

The Company's reportable segments are U.S., Canada and International ("Intl"). The Company is engaged principally in the exploration for and the development, production and marketing of natural gas, crude oil, and NGLs. The accounting policies for the segments are the same as those disclosed in Note 1 of Notes to Consolidated Financial Statements included in the Company's 2004 Form 10-K.

The following tables present information about the Company's reportable segments.

	Third Quarter							
	2005				2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Revenues	$ 1,028	$ 688	$ 237	$ 1,953	$ 687	$ 510	$ 222	$ 1,419
Depreciation, depletion and amortization	108	166	45	319	92	134	52	278
Income before income taxes	801	366	122	1,289	407	233	114	754
Capital expenditures	$ 472	$ 207	$ 51	$ 730	$ 169	$ 135	$ 55	$ 359

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	Nine Months							
	2005				2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Revenues	$ 2,644	$ 1,846	$ 725	$ 5,215	$ 1,941	$ 1,523	$ 596	$ 4,060
Depreciation, depletion and amortization	324	486	146	956	257	392	163	812
Income before income taxes	1,790	917	386	3,093	1,139	710	268	2,117
Capital expenditures	$ 884	$ 808	$ 119	$ 1,811	$ 505	$ 593	$ 132	$ 1,230

	September 30, 2005				December 31, 2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Properties-net	$ 4,520	$ 5,982	$ 1,371	$ 11,873	$ 3,984	$ 5,541	$ 1,417	$ 10,942
Goodwill	$ -	$ 1,093	$ -	$ 1,093	$ -	$ 1,054	$ -	$ 1,054

The following is a reconciliation of income before income taxes for reportable segments to consolidated income before income taxes.

	Third Quarter		Nine Months	
	2005	2004	2005	2004
	(In Millions)			
Income before income taxes for reportable segments	$ 1,289	$ 754	$ 3,093	$ 2,117
Corporate expenses	82	59	199	171
Interest expense	70	71	210	211
Other expense (income) - net	18	(5)	21	19
Consolidated income before income taxes	$ 1,119	$ 629	$ 2,663	$ 1,716

The following is a reconciliation of capital expenditures for reportable segments to consolidated capital expenditures.

	Third Quarter		Nine Months	
	2005	2004	2005	2004
	(In Millions)			
Total capital expenditures for reportable segments	$ 730	$ 359	$ 1,811	$ 1,230
Corporate capital expenditures	1	2	5	14
Total capital expenditures	$ 731	$ 361	$ 1,816	$ 1,244

The following is a reconciliation of segment net properties to consolidated amounts.

	September 30, 2005	December 31, 2004
	(In Millions)	
Properties - net for reportable segments	$ 11,873	$ 10,942

Corporate properties - net		77		91
Consolidated properties - net	$	11,950	$	11,033

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8. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations of $490 million at September 30, 2005 are included on the Consolidated Balance Sheet in Other Liabilities and Deferred Credits. Accretion expense is included in Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Income.

The following table reflects the changes in the Company's asset retirement obligations during the first nine months of 2005.

		(In Millions)
Carrying amount of asset retirement obligations as of December 31, 2004	$	468
Liabilities settled during the period		(11)
Current period accretion expense		22
Changes in foreign exchange rates during the period		11
Carrying amount of asset retirement obligations as of September 30, 2005	$	490

9. OIL AND GAS PROPERTIES

During the quarter ended June 30, 2005, the Company adopted the requirements of the Financial Accounting Standards Board ("FASB") Staff Position No. FAS 19-1, *Accounting for Suspended Well Costs* ("FSP 19-1"). Upon the adoption of FSP 19-1, the Company evaluated all existing capitalized well costs under the provisions of FSP 19-1 and determined there was no impact to the Company's consolidated financial statements. The following table reflects the net changes in capitalized exploratory well costs for the nine-month period ended September 30, 2005.

		(In Millions)
Balance at January 1, 2005	$	23
Additions		48
Reclassifications to proved properties		(25)
Charged to expense		(5)
Balance at September 30, 2005	$	41
Capitalized less than one year since completion of drilling	$	41

At September 30, 2005, the Company had no deferred costs related to wells that have been completed for more than one year.

10. PROPERTY ACQUISITIONS AND DIVESTITURES

In August and September of 2005, the Company acquired certain oil and gas properties located in the Fort Worth Basin in Texas for approximately $140 million. During the first nine months of 2005, the Company also made acquisitions for other oil and gas properties totaling approximately $97 million in the aggregate.

In August and September of 2005, the Company sold 8,350,000 units of beneficial interest in the Permian Basin Royalty Trust ("Units") held by the Company, generating proceeds, after underwriting fees, of approximately $123 million. The Company recorded a pretax gain of $117 million on this sale. Net proceeds generated from the sale of Units were used for the acquisitions of oil and gas properties.

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11. GOODWILL

All of the Company’s goodwill is assigned to the Canadian reporting unit which consists of all of the Company’s Canadian subsidiaries. The following table reflects the changes in the carrying amount of goodwill during the first nine months of 2005 as it relates to the Canadian reporting unit.

		(In Millions)
Balance-December 31, 2004	$	1,054
Changes in foreign exchange rates during the period		39
Balance-September 30, 2005	$	1,093

12. INCOME TAXES

The Company’s effective income tax rate for the nine months ended September 30, 2005 is unchanged from the 34 percent rate for the year ended December 31, 2004. The nine months ended September 30, 2005 and the year ended December 31, 2004 included income tax benefits of $19 million or 1 percent and $68 million or 3 percent, respectively, related to reductions in the Company’s Canadian tax rates. The income tax benefits for the year ended December 31, 2004 were partially offset by an income tax expense of $26 million or 1 percent related to the planned repatriation of $500 million of eligible foreign earnings from Canada to the U.S. during 2005 under the one-time provisions of the American Jobs Creation Act of 2004. On October 27, 2005, the Company repatriated the $500 million of eligible foreign earnings from Canada to the U.S.

At September 30, 2005, $176 million of deferred income tax is classified as current and is included in Other Current Assets on the Consolidated Balance Sheet.

13. RETIREMENT BENEFITS

The Company's U.S. pension plans are non-contributory defined benefit plans covering all eligible U.S. employees. The benefits are based on years of credited service and final average compensation. Effective January 1, 2003, the Company amended its U.S. pension plan to provide cash balance benefits to new employees. U.S. employees hired before January 1, 2003, were given the choice to remain in the prior plan or accrue future benefits under the cash balance formula. Contributions to the tax qualified plans are limited to amounts that are currently deductible for tax purposes. Contributions are intended to provide not only for benefits attributed to service-to-date but also for those expected to be earned in the future. Burlington Resources Canada (Hunter) Ltd. also provides a pension plan and postretirement benefits to a closed group of employees and retirees.

The Company provides postretirement medical, dental and life insurance benefits for a closed group of retirees and their dependents. The Company also provides limited retiree life insurance benefits to employees who retire under the pension plan. The postretirement benefit plans are unfunded, therefore, the Company funds claims on a cash basis.

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The Company’s net periodic benefit cost for its plans is comprised of the following components.

	Third Quarter			
	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In Millions)			
Benefit cost for the plans includes the following components				
Service cost	$ 3	$ 2	$ -	$ -
Interest cost	4	3	1	-
Expected return on plan asset	(4)	(3)	-	-
Recognized net actuarial loss	2	2	-	-
Net benefit cost	$ 5	$ 4	$ 1	$ -

	Nine Months			
	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In Millions)			
Benefit cost for the plans includes the following components				
Service cost	$ 9	$ 8	$ -	$ -
Interest cost	10	9	2	2
Expected return on plan asset	(10)	(9)	-	-
Recognized net actuarial loss	4	4	-	-
Net benefit cost	$ 13	$ 12	$ 2	$ 2

During the third quarter of 2005, the Company contributed $15 million to its pension plans. The Company expects to contribute a total of $46 million to its pension plans during 2005, of which $24 million remains unfunded as of September 30, 2005. The assumptions used in the valuation of the Company’s retirement plans and the target investment allocations have not changed since December 31, 2004.

14. RECENT ACCOUNTING PRONOUNCEMENTS

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company’s fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS No. 154 to have a material impact on the Company’s consolidated financial position, results of operations or cash flows.

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In December 2004, the FASB issued SFAS No. 123 (revised 2004) or SFAS No. 123(R), *Share-Based Payment.* This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. In April 2005, the Securities and Exchange Commission issued a rule that amends the date for compliance with SFAS No. 123(R). As a result, the Company will adopt this statement on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective application method, the Company will apply the standard to new awards and to awards modified, repurchased, or cancelled after the required effective date. Additionally, compensation cost for the unvested portion of awards outstanding as of the required effective date will be recognized as compensation expense as the requisite service is rendered after the required effective date. The adoption of this statement is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

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

Outlook

The Company strives to achieve both production growth and sector-leading financial returns when compared to other independent oil and gas exploration and production companies. This requires the continuous development of natural gas and crude oil reserves to fuel growth, while maintaining a rigorous focus on cost structure and capital efficiency.

The Company has a goal to achieve between three and eight percent average annual production growth. Production growth in 2005 is expected to be driven by steady production growth in North America.

Some of the Company's oil and gas facilities in south Louisiana and adjacent areas sustained minor damages as a result of Hurricanes Katrina and Rita. During the quarter, storm-related production curtailments temporarily peaked at 180 MMCFE per day but the curtailments had declined to approximately 30 MMCFE per day by late-October. Full restoration of the Company's shut-in production will depend on the pace of the industry's restoration of its services and facilities.

Future International production volumes will be impacted by the timing of the resumption of operations at the Rivers Field natural gas processing plant in the United Kingdom ("Rivers Field Plant"). The Company continues to conduct repairs and audit the design of certain components of the Rivers Field Plant. These activities are intended to address various construction and operational issues that occurred during commissioning and start-up of the plant.

The Company's current estimate for full year 2005 production volumes is expected to average between 2,840 and 2,890 MMCFE per day. This estimate does not include any production volumes from the Rivers Field Plant. The Company expects fourth quarter production volumes to average between 2,830 and 2,950 MMCFE per day.

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Below are estimated and actual costs and expenses for full year 2005 and 2004, respectively.

		2005		2004
		(Per Mcfe)		
Transportation expense	$	0.46 to $0.50	$	0.44
Operating costs		0.62 to 0.66		0.57
Depreciation, depletion and amortization (“DD&A”)		1.20 to 1.30		1.10
Administrative	$	0.19 to $0.22	$	0.21
		(In Millions)		
Exploration costs	$	265 to $ 285	$	258
Interest expense	$	270 to $ 290	$	282

In 2005, the Company’s operating costs are expected to increase about 9 to 16 percent over 2004 on a per unit-of-production basis as a result of higher industry service costs. DD&A expense is expected to increase about 9 to 18 percent in 2005 compared to 2004, primarily as a result of asset additions with higher unit-of-production rates and unfavorable exchange rate impacts. Transportation expense is expected to increase 5 to 14 percent over 2004 on a unit-of-production basis due primarily to International operations. The Company expects administrative expenses to range from a decrease of 10 percent to an increase of 5 percent from 2004 on a per unit-of-production basis. This range is primarily related to stock-based compensation, excluding stock options, and is expected to vary based on the performance of the Company’s stock price. Exploration costs are expected to increase in 2005 compared to 2004 as a result of increased exploration activity. These costs are primarily dependent upon the size of the Company’s drilling program, timing, and the success it has in finding commercial hydrocarbons, which cannot be precisely forecasted. Therefore, it is difficult to accurately estimate these costs.

Commodity prices are impacted by many factors that are outside of the Company's control. Historically, commodity prices have been volatile and the Company expects them to remain that way in the future. Commodity prices are affected by supply, market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, the Company cannot accurately predict future natural gas, NGLs and crude oil prices, and therefore, it cannot determine what impact increases or decreases in production volumes will have on future revenues or net operating cash flows. However, based on the estimated range of average daily natural gas production in 2005, the Company estimates that a $0.10 per MCF change in natural gas prices would have an impact on full year 2005 natural gas revenues of approximately $69 to $70 million. Also, based on the estimated range of average daily crude oil production in 2005, the Company estimates that a $1.00 per barrel change in crude oil prices would have an impact on full year 2005 crude oil revenues of approximately $33 to $34 million.

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to the Company's long-term success. In July 2005, the Company’s Board of Directors (“Board”) approved an increase in the Company’s capital expenditures for 2005 to $2.4 billion, excluding acquisitions. During the first nine months of 2005, acquisition transactions totaled approximately $237 million. For more information on the Company’s 2005 capital program, see the capital expenditures discussion on page 21 of this report.

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Financial Condition and Liquidity

The Company’s total debt to total capital (total capital is defined as total debt and stockholders’ equity) ratio at September 30, 2005 and December 31, 2004 was 33 percent and 36 percent, respectively. The improvement in this ratio was primarily attributable to higher net income partially offset by the repurchase of Common Stock. Based on the current price environment, the Company believes that it will generate sufficient cash from operating activities to fund its 2005 capital expenditures, excluding any potential major acquisition(s). At September 30, 2005, the Company had $2,816 million of cash and cash equivalents on hand, of which $2,040 million was located in Canada, $513 million in the U.S. and $263 million in International. On October 27, 2005, the Company repatriated $500 million of eligible foreign earnings from Canada to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004.

Burlington Resources Capital Trust I, Burlington Resources Capital Trust II (collectively, “the Trusts”), BR and Burlington Resources Finance Company (“BRFC”) have a shelf registration statement of $1.5 billion on file with the Securities and Exchange Commission (“SEC”). Pursuant to the registration statement, BR may issue debt securities, shares of common stock or preferred stock. In addition, BRFC may issue debt securities and the Trusts may issue trust preferred securities. Net proceeds, terms and pricing of offerings of securities issued under the shelf registration statement will be determined at the time of the offerings. BRFC and the Trusts are wholly owned finance subsidiaries of BR and have no independent assets or operations other than transferring funds to BR’s subsidiaries. Any debt issued by BRFC is fully and unconditionally guaranteed by BR. Any trust preferred securities issued by the Trusts are also fully and unconditionally guaranteed by BR. In December 2001, the Company’s Board authorized the Company to redeem, exchange or repurchase up to an aggregate of $990 million principal amount of debt securities. As of September 30, 2005, no debt securities had been redeemed, exchanged or repurchased under this authorization.

On April 14, 2005, the Company filed as co-registrant with the Permian Basin Royalty Trust (“Royalty Trust”) a registration statement on Form S-3 with the SEC registering the sale from time to time, in one or more offerings, up to 27,577,741 units of beneficial interest in the Royalty Trust (“Units”) held by the Company. In August and September of 2005, the Company sold 8,350,000 Units, generated proceeds, after underwriting fees, of approximately $123 million. Net proceeds generated from the sale of Units were used for the acquisitions of oil and gas properties.

The Company has a $1.5 billion revolving credit facility (“Credit Facility”) that includes (i) a US$500 million Canadian sub-facility and (ii) a US$750 million sub-limit for the issuance of letters of credit, including up to US$250 million in letters of credit under the Canadian subfacility. On August 17, 2005, the Company amended the Credit Facility to extend the expiration date from July 2009 to August 2010. Under the covenants of the Credit Facility, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements). The Credit Facility is available to repay debt due within one year, therefore commercial paper, credit facility notes and fixed-rate debt due within one year are generally classified as long-term debt. At September 30, 2005, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

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Net cash provided by operating activities during the first nine months of 2005 was $2,963 million, representing an increase of $489 million over the same period in 2004. Commodity prices, production volumes and costs and expenses are key drivers of net operating cash flow generation for the Company. Net cash provided by operating activities increased primarily due to higher net income resulting from higher commodity prices and higher crude oil and NGLs production volumes. These increases were partially offset by lower natural gas production volumes, higher costs and expenses, excluding non-cash expenses, and higher working capital needs. Commodity prices increased over the comparable period last year, resulting in higher revenues of $1,086 million. Crude oil and NGLs production volumes increased resulting in higher revenues of $98 million. Lower natural gas production volumes resulted in reduced revenues of $41 million. Working capital needs increased $179 million during the first nine months of 2005 compared to the first nine months of 2004.

Costs and expenses referred to in this discussion include operating costs, taxes other than income taxes, transportation expense, and administrative expense. These costs and expenses in the first nine months of 2005 increased $184 million over the first nine months of 2004. Taxes other than income taxes and operating costs represented the largest increase in these costs. Taxes other than income taxes include severance and ad valorem taxes, and severance taxes are directly correlated to crude oil and natural gas revenues. Severance and ad valorem taxes accounted for 32 percent of the increase in costs and expenses compared to the first nine months of 2004. Operating costs include well operating expenses, which are expenses incurred to operate the Company’s wells and equipment on producing leases. Well operating expenses accounted for 24 percent of the increase in costs and expenses compared to the first nine months of 2004. Transportation expense and administrative expense represented increases of 19 percent and 13 percent, respectively, in costs and expenses during the period compared to 2004.

Although the Company believes that 2005 production volumes will exceed 2004 levels, it is unable to predict future commodity prices, and as a result cannot provide any assurance about future levels of net cash provided by operating activities. Net cash provided by operating activities during the first nine months of 2005 is not necessarily indicative of future cash flows from operating activities.

In December 2000, the Company’s Board authorized the repurchase of up to $1 billion of the Company’s Common Stock. Through April 30, 2003, the Company had repurchased $816 million of its Common Stock under the program authorized in December 2000. In April 2003, the Company’s Board voted to restore the authorization level to $1 billion effective May 1, 2003. Through December 7, 2004, the Company had repurchased $712 million of its Common Stock under the program authorized in April 2003. In December 2004, the Company’s Board voted to restore the authorization level to $1 billion.

During the first nine months of 2005, the Company repurchased approximately 13 million shares of its Common Stock for approximately $693 million and, as of September 30, 2005, had the authority to repurchase an additional $259 million of its Common Stock under the current authorization. On October 26, 2005, the Company announced that its Board voted to restore the current authorization level to $1 billion.

The Company and its subsidiaries are named defendants in numerous lawsuits and named parties in numerous governmental and other proceedings arising in the ordinary course of business. While the outcome of these lawsuits and other proceedings cannot be predicted with certainty, management believes these matters will not have a material adverse effect on the consolidated financial position of the Company, although results of operations and cash flows could be significantly impacted in the reporting periods in which such matters are resolved.

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The Company has certain other commitments and uncertainties related to its normal operations. Management believes that there are no other commitments or uncertainties that will have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

Capital Expenditures

	Nine Months 2005	Nine Months 2004	Increase (Decrease)	% Increase (Decrease)
	($ In Millions)			
Oil and gas				
Development	$ 1,242	$ 883	$ 359	41%
Exploration	297	194	103	53
Acquisitions	237	85	152	179
Total oil and gas	1,776	1,162	614	53
Plants and pipelines	25	58	(33)	(57)
Administrative and other	15	24	(9)	(38)
Total capital expenditures	$ 1,816	$ 1,244	$ 572	46%

The Company's total capital expenditures during the first nine months of 2005 increased 46 percent compared to the first nine months of 2004. The Company utilizes a disciplined approach to capital spending. Property acquisitions during the first nine months of 2005 total approximately $237 million compared to $85 million during the first nine months of 2004. In August and September of 2005, the Company acquired certain oil and gas properties located in the Fort Worth Basin in Texas for approximately $140 million. During the first nine months of 2005, the Company also made acquisitions for other oil and gas properties totaling approximately $97 million in the aggregate. Excluding acquisitions, the Company's capital spending related to internal development and exploration increased 43 percent compared to the first nine months of 2004. In order to fund additional exploration and development drilling, increase lease purchases in North America and meet rising industry service costs, the Company expects its capital expenditures in 2005, excluding property acquisitions, to approximate $2.4 billion, representing a 20 percent increase over expectations announced in late 2004. This capital spending includes the costs associated with the initiation of projects in Egypt and Algeria, and represents an increase of 44 percent over 2004. Capital expenditures in 2005 are expected to be primarily for internal development and exploration of oil and gas properties and are expected to be funded from internally generated cash flows.

Dividends

On October 26, 2005, the Company's Board declared a quarterly common stock cash dividend of $0.10 per share. The record and payment dates for the quarterly dividend are December 9, 2005 and January 10, 2006, respectively.

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Recent Accounting Pronouncements

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company's fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but management does not currently expect SFAS No. 154 to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123 (revised 2004) or SFAS No. 123(R), *Share-Based Payment.* This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. In April 2005, the SEC issued a rule that amends the date for compliance with SFAS No. 123(R). As a result, the Company will adopt this statement on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective application method, the Company will apply the standard to new awards and to awards modified, repurchased, or cancelled after the required effective date. Additionally, compensation cost for the unvested portion of awards outstanding as of the required effective date will be recognized as compensation expense as the requisite service is rendered after the required effective date. The adoption of this statement is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Results of Operations -Third Quarter of 2005 Compared to Third Quarter of 2004

The Company reported net income of $748 million or $1.96 diluted earnings per common share in the third quarter of 2005 compared to net income of $394 million or $1.00 diluted earnings per common share in the third quarter of 2004. Net income in the third quarter of 2005 includes a pretax gain of $117 million ($73 million after tax or $0.19 per diluted share) related to the sale of 8,350,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company.

Below is a discussion of revenues, price, and volume variances.

Revenue Variances

	Third Quarter			%
	2005	2004	Increase	Increase
	($ In Millions)			
Revenues				
Natural gas	$ 1,249	$ 927	$ 322	35%
NGLs	211	161	50	31
Crude oil	478	322	156	48
Processing and other	15	9	6	67
Total revenues	$ 1,953	$ 1,419	$ 534	38%

Price and Volume Variances

	Third Quarter 2005	Third Quarter 2004	Increase	% Increase	Increase (In Millions)
Price variance					
Natural gas sales prices (per MCF)	$ 7.19	$ 5.29	$ 1.90	36%	$ 330
NGLs sales prices (per Bbl)	34.69	26.26	8.43	32	51
Crude oil sales prices (per Bbl)	$ 55.86	$ 41.06	$ 14.80	36%	126
Total price variance					$ 507

	Third Quarter 2005	Third Quarter 2004	Increase (Decrease)	% Increase (Decrease)	Increase (Decrease) (In Millions)
Volume variance					
Natural gas sales volumes (MMCF per day)	1,888	1,906	(18)	(1)%	$ (8)
NGLs sales volumes (MBbls per day)	66.1	66.5	(0.4)	(1)	(1)
Crude oil sales volumes (MBbls per day)	93.0	85.1	7.9	9%	30
Total volume variance					$ 21

Revenues

The Company's consolidated revenues increased $534 million in the third quarter of 2005 compared to the third quarter of 2004. Higher revenues were due primarily to higher commodity prices and higher crude oil sales volumes, resulting in increased revenues of $507 million and $30 million, respectively. Higher revenues related to higher commodity prices and higher crude oil sales volumes were partially offset by lower natural gas and NGLs sales volumes, resulting in reduced revenues of $9 million. Revenue variances related to commodity prices and sales volumes are described below.

Price Variances

Commodity prices are one of the key drivers of earnings and net operating cash flow generation. Higher commodity prices contributed $507 million to increased revenues in the third quarter of 2005 compared to the third quarter of 2004. Average natural gas prices, including a $0.19 realized loss per MCF related to hedging activities, increased $1.90 per MCF during the third quarter of 2005 resulting in increased revenues of $330 million. Average crude oil prices, including a $1.79 realized loss per barrel related to hedging activities, increased $14.80 per barrel in the third quarter of 2005, resulting in increased revenues of $126 million. Average NGLs prices increased $8.43 per barrel in the third quarter of 2005, resulting in higher revenues of $51 million.

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Volume Variances

Sales volumes are another key driver that impact the Company's earnings and net operating cash flow generation. Higher average crude oil sales volumes, which increased 7.9 MBbls in the third quarter of 2005, resulted in increased revenues of $30 million compared to the third quarter of 2004. Crude oil sales volumes increased primarily due to higher production of 10.4 MBbls per day in the Cedar Creek Anticline and 4.4 MBbls per day in the Bakken Shale partially offset by lower production of 5.3 MBbls per day in China. Average natural gas sales volumes decreased 18 MMCF per day in the third quarter of 2005, resulting in lower revenues of $8 million. Average natural gas sales volumes decreased primarily due to lower production of 46 MMCF per day in the San Juan Basin, 31 MMCF per day in south Louisiana, 19 MMCF per day at Millom and Dalton in the East Irish Sea, and 17 MMCF per day from the Dutch sector of the North Sea. These decreases were partially offset by higher production volumes of 83 MMCF per day at Savell (Bossier) Field and 9 MMCF per day in the Fort Worth Basin. Average NGLs sales volumes decreased 0.4 MBbls per day in the third quarter of 2005, resulting in lower revenues of $1 million compared to the same quarter last year. NGLs sales volumes decreased primarily due to lower production of 1.1 MBbls per day in south Louisiana partially offset by higher production of 0.6 MBbls per day in the Fort Worth Basin.

Below is a discussion of total costs and other income - net.

Total Costs and Other Income - Net

	Third Quarter 2005	Third Quarter 2004	Increase (Decrease)	% Increase (Decrease)
	($ In Millions)			
Costs and other income - net				
Taxes other than income taxes	$ 94	$ 67	$ 27	40%
Transportation expense	127	112	15	13
Operating costs	176	152	24	16
Depreciation, depletion and amortization	325	284	41	14
Exploration costs	65	55	10	18
Administrative	76	54	22	41
Interest expense	70	71	(1)	(1)
Gain on disposal of assets	(117)	-	117	-
Other expense (income) - net	18	(5)	23	460
Total costs and other income - net	$ 834	$ 790	$ 44	6%

Total costs and other income - net increased $44 million in the third quarter of 2005 compared to the third quarter of 2004. The increase in total costs and other income - net was primarily due to the items discussed below. Changes in foreign currencies versus the U.S. dollar could impact costs and expenses in future periods. However, the Company cannot predict what impact the exchange rates will have on future costs and expenses.

DD&A expense increased $41 million primarily due to asset additions with higher unit-of-production rates and higher foreign exchange rates. Taxes other than income taxes increased $27 million primarily due to higher severance taxes resulting from higher crude oil and natural gas revenues.

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In general, operating costs are higher due to industry service cost pressures. Operating costs increased $24 million primarily due to higher well operating expenses related to well activity levels, foreign currency rates, maintenance and repairs, fuel, and electricity expenses. Administrative expense increased $22 million primarily due to stock-based compensation, excluding stock options, related to a higher stock price for the Company. Transportation expense increased $15 million primarily in the U.S. and International operations.

Exploration costs increased $10 million primarily due to higher dry hole costs. Exploration costs fluctuate from period to period primarily due to the amount the Company expends on its exploration capital program, timing, and its success rate. The current period exploration costs are not necessarily indicative of future costs.

Gain on disposal of assets increased $117 million due to the sale of 8,350,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company. Other expense - net increased primarily due to higher legal cost accruals partially offset by higher interest income. The Company recorded legal cost accruals of $29 million and $200 thousand during the third quarter of 2005 and 2004, respectively. The Company recorded interest income of $16 million and $6 million during the third quarter of 2005 and 2004, respectively.

Income Tax Expense

Income tax expense increased $136 million in the third quarter of 2005 compared to the third quarter of 2004. The increase in income tax expense was primarily due to higher pretax income of $490 million. During the third quarter of 2005 and 2004, the Company recorded income tax benefits of $40 million and income tax expense of $12 million, respectively, related to return as filed adjustments. The Company recorded income tax benefits of $10 million related to the Canadian rate reductions in the third quarter of 2005 compared to none in the third quarter of 2004. The Company also recorded income tax expense of $28 million and $4 million in the third quarter of 2005 and 2004, respectively, related to taxes on foreign income in excess of U.S. rates.

Results of Operations - Nine Months of 2005 Compared to Nine Months of 2004

The Company reported net income of $1,756 million or $4.56 diluted earnings per common share in the first nine months of 2005 compared to net income of $1,127 million or $2.84 diluted earnings per common share in the first nine months of 2004. Net income in the first nine months of 2005 includes a pretax gain of $117 million ($73 million after tax or $0.19 per diluted share) related to the sale of 8,350,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company.

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Below is a discussion of revenues, price, and volume variances.

Revenue Variances

	Nine Months 2005	Nine Months 2004	Increase	% Increase
		($ In Millions)		
Revenues				
Natural gas	$ 3,346	$ 2,803	$ 543	19%
NGLs	565	423	142	34
Crude oil	1,267	809	458	57
Processing and other	37	25	12	48
Total revenues	$ 5,215	$ 4,060	$ 1,155	28%

Price and Volume Variances

	Nine Months 2005	Nine Months 2004	Increase	% Increase	Increase (In Millions)
Price variance					
Natural gas sales prices (per MCF)	$ 6.46	$ 5.33	$ 1.13	21%	$ 584
NGLs sales prices (per Bbl)	30.90	24.06	6.84	28	125
Crude oil sales prices (per Bbl)	$ 50.08	$ 35.17	$ 14.91	42%	377
Total price variance					$ 1,086

	Nine Months 2005	Nine Months 2004	Increase (Decrease)	% Increase (Decrease)	Increase (Decrease) (In Millions)
Volume variance					
Natural gas sales volumes (MMCF per day)	1,898	1,919	(21)	(1)%	$ (41)
NGLs sales volumes (MBbls per day)	67.0	64.2	2.8	4	17
Crude oil sales volumes (MBbls per day)	92.7	83.9	8.8	10%	81
Total volume variance					$ 57

Revenues

The Company's consolidated revenues increased $1,155 million in the first nine months of 2005 compared to the first nine months of 2004. Higher revenues were due primarily to higher commodity prices and higher crude oil and NGLs sales volumes, resulting in increased revenues of $1,086 million and $98 million, respectively. Higher revenues related to higher commodity prices and higher crude oil and NGLs sales volumes were partially offset by lower natural gas sales volumes, resulting in reduced revenues of $41 million. Revenue variances related to commodity prices and sales volumes are described below.

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Price Variances

Commodity prices are one of the key drivers of earnings and net operating cash flow generation. Higher commodity prices contributed $1,086 million to increased revenues in the first nine months of 2005 compared to the first nine months of 2004. Average natural gas prices, including a $0.05 realized loss per MCF related to hedging activities, increased $1.13 per MCF during the first nine months of 2005 resulting in increased revenues of $584 million. Average crude oil prices, including a $0.75 realized loss per barrel related to hedging activities, increased $14.91 per barrel in the first nine months of 2005, resulting in increased revenues of $377 million. Average NGLs prices increased $6.84 per barrel in the first nine months of 2005, resulting in higher revenues of $125 million.

Volume Variances

Sales volumes are another key driver that impact the Company's earnings and net operating cash flow generation. Higher crude oil and NGLs sales volumes in the first nine months of 2005 resulted in increased revenues of $98 million compared to the first nine months of 2004. Average crude oil sales volumes increased 8.8 MBbls per day in the first nine months of 2005, resulting in increased revenues of $81 million. Crude oil sales volumes increased primarily due to higher production of 9.3 MBbls per day in the Cedar Creek Anticline and 3.9 MBbls per day in the Bakken Shale partially offset by lower production of 2.5 MBbls per day in China and 1.8 MBbls per day in Ecuador. Average NGLs sales volumes increased 2.8 MBbls per day in the first nine months of 2005, resulting in higher revenues of $17 million compared to the same period last year. NGLs sales volumes increased primarily due to higher production of 1.1 MBbls per day in Canada and 1.0 MBbls per day at the Waddell Ranch Field. Average natural gas sales volumes decreased 21 MMCF per day in the first nine months of 2005, resulting in lower revenues of $41 million. Average natural gas sales volumes decreased primarily due to lower production of 33 MMCF per day in the San Juan Basin, 22 MMCF per day at Millom and Dalton in the East Irish Sea, 16 MMCF per day in the Dutch sector of the North Sea, 13 MMCF per day in Canada and 11 MMCF per day in south Louisiana. These decreases were partially offset by higher production volumes of 61 MMCF per day from the drilling programs at Savell (Bossier) Field and 11 MMCF per day at Madden Field.

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Below is a discussion of total costs and other income - net.

Total Costs and Other Income - Net

	Nine Months 2005	Nine Months 2004	Increase (Decrease)	% Increase (Decrease)
	($ In Millions)			
Costs and other income - net				
Taxes other than income taxes	$ 250	$ 188	$ 62	33%
Transportation expense	364	329	35	11
Operating costs	490	426	64	15
Depreciation, depletion and amortization	975	831	144	17
Exploration costs	183	177	6	3
Administrative	176	153	23	15
Interest expense	210	211	(1)	-
(Gain)/loss on disposal of assets	(117)	10	127	1,270
Other expense - net	21	19	2	11
Total costs and other income - net	$ 2,552	$ 2,344	$ 208	9%

Total costs and other income - net increased $208 million in the first nine months of 2005 compared to the first nine months of 2004. The increase in total costs and other income - net was primarily due to the items discussed below. Changes in foreign currencies versus the U.S. dollar could impact costs and expenses in future periods. However, the Company cannot predict what impact the exchange rates will have on future costs and expenses.

DD&A expense increased $144 million primarily due to asset additions with higher unit-of-production rates and higher foreign exchange rates. In general, operating costs are higher due to industry service cost pressures. Operating costs increased $64 million primarily due to higher well operating expenses related to workovers, well activity levels, foreign currency rates, maintenance and repairs, fuel, and electricity expenses.

Taxes other than income taxes increased $62 million primarily due to higher severance taxes resulting from higher crude oil and natural gas revenues. Administrative expense increased $23 million primarily due to stock-based compensation, excluding stock options, related to a higher stock price for the Company. Transportation expense increased $35 million primarily in the U.S. and International operations.

Exploration costs increased due to higher geological and geophysical costs, delay rentals and other expenses of $12 million, higher amortization of undeveloped lease costs of $8 million partially offset by lower dry hole costs of $5 million and lower drilling rig expenses of $9 million. Exploration costs fluctuate from period to period primarily due to the amount the Company expends on its exploration capital program, timing, and its success rate. The current period exploration costs are not necessarily indicative of future costs.

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Gain on disposal of assets of $117 million in 2005 is due to the sale of 8,350,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company. Other expense - net increased primarily due to higher legal cost accruals and higher environmental cost accruals partially offset by higher interest income. The Company recorded legal cost accruals of $39 million and $17 million during the first nine months of 2005 and 2004, respectively. The Company recorded environmental cost accruals of $7 million during the first nine months of 2005 compared to none in the first nine months of 2004. The Company recorded interest income of $42 million and $14 million during the first nine months of 2005 and 2004, respectively.

Income Tax Expense

Income tax expense increased $318 million in the first nine months of 2005 compared to the first nine months of 2004. The increase in income tax expense was primarily due to higher pretax income of $947 million. During the first nine months of 2005 and 2004, the Company recorded income tax benefits of $68 million and $53 million, respectively, related to cross-border financing. During the first nine months of 2005 and 2004, the Company recorded income tax benefits of $40 million and income tax expense of $12 million, respectively, related to return as filed adjustments. The Company recorded income tax benefits of $19 million and $27 million related to the Canadian rate reductions in the first nine months of 2005 and 2004, respectively. The Company also recorded income tax expense of $80 million and $36 million in the first nine months of 2005 and 2004, respectively, related to taxes on foreign income in excess of U.S. rates.

ITEM 3. Quantitative and Qualitative Disclosures about Commodity Risk

Substantially all of the Company's crude oil and natural gas production is sold on the spot market or under short-term contracts at market sensitive prices. Spot market prices for domestic crude oil and natural gas are subject to volatile trading patterns in the commodity futures market, including among others, the New York Mercantile Exchange (“NYMEX”). Quality differentials, worldwide political developments and the actions of the Organization of Petroleum Exporting Countries also affect crude oil prices.

There is also a difference between the NYMEX futures contract price for a particular month and the actual cash price received for that month in a North America producing basin or at a North America market hub, which is referred to as the "basis differential." Basis differentials can vary widely depending on various factors, including but not limited to, local supply and demand.

The Company utilizes over-the-counter price and basis swaps as well as options to hedge its production in order to decrease its price risk exposure. The gains and losses realized as a result of these price and basis derivative transactions are substantially offset when the hedged commodity is delivered. Under certain circumstances, the Company also uses price swaps to convert natural gas sold under fixed-price contracts to market sensitive prices.

The Company recognizes all derivatives as either assets or liabilities on the balance sheet and measures those instruments at fair value. The requisite accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

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The Company uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of natural gas and crude oil may have on the fair value of the Company's derivative instruments. For example, at September 30, 2005, the potential increase in fair value of derivative instruments assuming a 10 percent adverse movement (an increase in the underlying commodity prices) would result in an $160 million decrease in the net unrealized gain.

For purposes of calculating the hypothetical change in fair value, the relevant variables include the type of commodity, the commodity futures prices, the volatility of commodity prices and the basis and quality differentials. The hypothetical change in fair value is calculated by multiplying the difference between the hypothetical price (adjusted for any basis or quality differentials) and the contractual price by the contractual volumes.

Based on commodity prices as of September 30, 2005, the Company expects to reclassify losses of $428 million ($265 million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At September 30, 2005, the Company had derivative assets of $7 million and derivative liabilities of $446 million, of which $7 million and $13 million are included in Other Current Assets and Other Liabilities and Deferred Credits, respectively, on the Consolidated Balance Sheet.

ITEM 4. Controls and Procedures

Under the supervision and with the participation of certain members of the Company's management, including the Chief Executive Officer and Chief Financial Officer, the Company completed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) to the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer believe that the disclosure controls and procedures were effective as of the end of the period covered by this report with respect to timely communicating to them and other members of management responsible for preparing periodic reports all material information required to be disclosed in this report as it relates to the Company and its consolidated subsidiaries.

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The Company's management does not expect that its disclosure controls and procedures or its internal control over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some person or by collusion of two or more people. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Accordingly, the Company's disclosure controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our disclosure control system are met and, as set forth above, the Company's management has concluded, based on their evaluation as of the end of the period, that our disclosure controls and procedures were sufficiently effective to provide reasonable assurance that the objectives of our disclosure control system were met.

There was no change in the Company's internal control over financial reporting during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Forward-looking Statements

This Quarterly Report contains projections and other forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These projections and statements reflect the Company’s current views with respect to future events and financial performance. No assurances can be given, however, that these events will occur or that these projections will be achieved and actual results could differ materially from those projected as a result of certain factors. A discussion of these factors is included in the Company’s 2004 Annual Report on Form 10-K.

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PART II - OTHER INFORMATION

ITEM 1. Legal Proceedings

See Note 5 of Notes to Consolidated Financial Statements.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities (1)

Period	(a) Total Number of Shares Purchased		(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs		(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
	(In Thousands, Except per Share Amounts)					
July 1, 2005 - July 31, 2005	1,400	$	60.16	1,400	$	423,890
August 1, 2005 - August 31, 2005	1,351		66.77	1,351		333,688
September 1, 2005 - September 30, 2005	972		76.94	972	$	258,898
Total	3,723	$	66.94	3,723		

(1) In December 2000, the Company announced that its Board of Directors ("Board") authorized the repurchase of up to $1 billion of the Company's Common Stock. Through April 30, 2003, the Company had repurchased $816 million of its Common Stock under the program authorized in December 2000. In April 2003, the Company announced that its Board voted to restore the authorization level to $1 billion effective May 1, 2003. Through December 7, 2004, the Company had repurchased $712 million of its Common Stock under the program authorized in April 2003. In December 2004, the Company announced that the Board voted to restore the authorization level to $1 billion. Through September 30, 2005, the Company had the authority to purchase $259 million of its Common Stock under the current authorization. On October 26, 2005, the Company announced that its Board voted to restore the authorization level to $1 billion.

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ITEM 6. Exhibits

The following exhibits are filed as part of this report.

Exhibit	Nature of Exhibit
4.1*	The Company and its subsidiaries either have filed with the Securities and Exchange Commission or upon request will furnish a copy of any instrument with respect to long-term debt of the Company
10.1*	First Amendment, effective August 17, 2005, to the $1.5 billion Credit Agreement, dated July 29, 2004, between Burlington Resources Inc., Burlington Resources Canada Ltd., and Burlington Resources Canada (Hunter) Ltd., as Borrowers, and JPMorgan Chase Bank, as administrative agent (Exhibit 10.1 to Form 8-K filed August 22, 2005)
31.1	Rule 13a-14(a)/15d-14(a) Certification executed by Bobby S. Shackouls, Chairman of the Board, President and Chief Executive Officer of the Company
31.2	Rule 13a-14(a)/15d-14(a) Certification executed by Joseph P. McCoy, Senior Vice President and Chief Financial Officer of the Company
32.1	Section 1350 Certification
32.2	Section 1350 Certification

* Exhibit incorporated by reference.

Items 3, 4 and 5 of Part II are not applicable and have been omitted.

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SIGNATURES

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

BURLINGTON RESOURCES INC.
(Registrant)

By	/S/ JOSEPH P. McCOY Joseph P. McCoy Senior Vice President and Chief Financial Officer
By	/S/ DANE E. WHITEHEAD Dane E. Whitehead Vice President, Controller and Chief Accounting Officer

Date: November 2, 2005

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