BURLINGTON RESOURCES INC
Form 10-Q
August 03, 2005

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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 June 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 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 June 30, 2005	381,047,633

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PART I FINANCIAL INFORMATION

ITEM 1. Financial Statements

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF INCOME
(UNAUDITED)

	Second Quarter		Six Months	
	2005	2004	2005	2004
	(In Millions, Except per Share Amounts)			
Revenues	$1,686	$1,333	$3,262	$2,641
Costs and Other Expense Net				
Taxes Other than Income Taxes	82	62	156	121
Transportation Expense	120	107	237	217
Operating Costs	160	143	314	274
Depreciation, Depletion and Amortization	322	270	650	547
Exploration Costs	67	62	118	122
Administrative	49	51	100	99
Interest Expense	70	69	140	140
Loss on Disposal of Assets	1	2		10
Other Expense Net	10	27	3	24
Total Costs and Other Expense Net	881	793	1,718	1,554
Income Before Income Taxes	805	540	1,544	1,087
Income Tax Expense	268	161	536	354
Net Income	$ 537	$ 379	$1,008	$ 733
Basic Earnings per Common Share	$ 1.41	$ 0.96	$ 2.63	$ 1.86
Diluted Earnings per Common Share	$ 1.40	$ 0.96	$ 2.61	$ 1.85

See accompanying Notes to Consolidated Financial Statements.

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BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET
(UNAUDITED)

	June 30, 2005	December 31, 2004
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 2,385	$ 2,179
Accounts Receivable	1,071	994
Inventories	147	124
Other Current Assets	140	158
	3,743	3,455
Oil & Gas Properties (Successful Efforts Method)	18,732	17,943
Other Properties	1,610	1,544
	20,342	19,487
Accumulated Depreciation, Depletion and Amortization	9,060	8,454
Properties Net	11,282	11,033
Goodwill	1,035	1,054
Other Assets	211	202
Total Assets	$ 16,271	$ 15,744
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 1,126	$ 1,182
Taxes Payable	220	216
Accrued Interest	61	61
Dividends Payable	33	33
Deferred Income Taxes		48
Commodity Hedging Contracts and Other Derivatives	101	27
Other Current Liabilities	6	32
	1,547	1,599
Long-term Debt	3,886	3,887
Deferred Income Taxes	2,566	2,396

Other Liabilities and Deferred Credits	875	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	3,987	3,973
Retained Earnings	5,105	4,163
Deferred Compensation Restricted Stock	(22)	(14)
Accumulated Other Comprehensive Income	915	1,092
Cost of Treasury Stock (101,329,237 and 94,435,401 Shares for 2005 and 2004, respectively)	(2,593)	(2,208)
Stockholders Equity	7,397	7,011
Total Liabilities and Stockholders Equity	$16,271	$15,744

See accompanying Notes to Consolidated Financial Statements.

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

	Six Months 2005	Six Months 2004
	(In Millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,008	$ 733
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities		
Depreciation, Depletion and Amortization	650	547
Deferred Income Taxes	172	247
Exploration Costs	118	122
Loss on Disposal of Assets		10
Changes in Derivative Fair Values	1	(1)
Working Capital Changes		
Accounts Receivable	(84)	(200)
Inventories	(25)	(27)
Other Current Assets	(21)	(15)
Accounts Payable	(3)	52
Taxes Payable	19	60
Other Current Liabilities	(25)	3
Changes in Other Assets and Liabilities	(17)	13
Net Cash Provided By Operating Activities	1,793	1,544
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Properties	(1,133)	(881)
Proceeds from Sales and Other	24	(8)
Net Cash Used In Investing Activities	(1,109)	(889)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from Long-term Debt		41
Reduction in Long-term Debt	(1)	(1)
Dividends Paid	(66)	(59)
Common Stock Purchases	(441)	(194)
Common Stock Issuances	43	122
Net Cash Used In Financing Activities	(465)	(91)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(13)	(12)
Increase in Cash and Cash Equivalents	206	552

Cash and Cash Equivalents		
Beginning of Year	2,179	757
End of Period	$ 2,385	$1,309

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 382 million and 394 million for the second quarter of 2005 and 2004, respectively, and 384 million and 394 million for the first six 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 385 million and 397 million for the second quarter of 2005 and 2004, respectively, and 387 million and 397 million for the first six months of 2005 and 2004, respectively.

For the quarter ended June 30, 2005 and 2004, all shares attributable to outstanding options were dilutive. For the six months ended June 30, 2005 and 2004, approximately 17 thousand and 20 thousand 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.

	Second Quarter		Six Months	
	2005	2004	2005	2004
	(In Millions, except per Share Amounts)			
Net income as reported	$ 537	$ 379	$1,008	$ 733
Less: Pro forma stock-based employee compensation cost, after tax	(1)	(3)	(2)	(6)
Net income pro forma	$ 536	$ 376	$1,006	$ 727
Basic EPS as reported	$1.41	$0.96	$ 2.63	$1.86
Basic EPS pro forma	1.40	0.95	2.62	1.85
Diluted EPS as reported	1.40	0.96	2.61	1.85
Diluted EPS pro forma	1.39	$0.95	$ 2.60	$1.83

3. COMPREHENSIVE INCOME (LOSS)

	Six Months			
	2005		2004	
	(In Millions)			
Accumulated other comprehensive income - beginning of period		$1,092		$ 655
Net income	$1,008		$ 733	
Other comprehensive income (loss) net of tax				
Hedging activities				
Current period changes in fair value of settled contracts	(10)		(3)	
Reclassification adjustments for settled contracts	(4)		9	
Changes in fair value of outstanding hedging positions	(69)		(16)	
Hedging activities	(83)		(10)	
Foreign currency translation				
Foreign currency translation adjustments	(94)		(160)	
Total other comprehensive loss	(177)	(177)	(170)	(170)
Comprehensive income	$ 831		$ 563	

Accumulated other comprehensive income end of period	$ 915	$ 485

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

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Amount Gas (MMBTU)	Notional Amount Oil (Barrels)	Average Underlying Prices	Fair Value Asset (Liability) (In Millions)
2005	Swap	Cash flow	4,341,630		$ 5.26	$ (11)
	Swap	Not designated	6,150,000		(0.11)	
	Purchased put	Cash flow	84,059,756		5.91	10
	Written call	Cash flow	84,059,756		7.56	(24)
	Purchased put	Cash flow		3,680,000	43.33	1
	Written call	Cash flow		3,680,000	55.82	(22)
	Swap	Fair value	590,400		2.64	2
	N/A	Fair value (obligation)	590,400		2.65	(2)
2006	Swap	Cash flow	5,412,500		7.95	(30)
	Purchased put	Cash flow	32,290,000		6.63	11
	Written call	Cash flow	32,290,000		8.54	(31)
	Purchased put	Cash flow		1,970,000	48.86	5
	Written call	Cash flow		1,970,000	62.34	(11)
2007	Swap	Cash flow	760,000		$ 3.06	(3)
						$ (105)

As of June 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	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 June 30, 2005, the Company expects to reclassify losses of $97 million ($61 million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At June 30, 2005, the Company had derivative assets of $2 million and derivative liabilities of $108 million of which $2 million and $7 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 June 30, 2005. Hedging activities related to cash settlements on commodities decreased revenues $5 million and $13 million in the second quarter of 2005 and 2004, respectively. Hedging activities related to cash settlements on commodities increased revenues $6 million in the first six months of 2005 and decreased revenues $14 million in the first six months of 2004. In addition, a non-cash loss of $212 thousand and a non-cash gain of $1 million were recorded in revenues associated with ineffectiveness of cash-flow and fair-value hedges during the second quarter of 2005 and 2004, respectively. Also, a non-cash loss of $3 million and a non-cash gain of $1 million were recorded in revenues associated with ineffectiveness of cash-flow and fair-value hedges during the first six months of 2005 and 2004, respectively. A non-cash loss of $1 million and a non-cash gain of $32 thousand were recorded in revenues associated with changes in the fair value of derivative instruments that do not qualify for hedge accounting during the second quarter of 2005 and 2004, respectively. Non-cash losses of $1 million and $7 thousand were recorded in revenues associated with changes in the fair value of derivative instruments that do not qualify for hedge accounting during the first six months of 2005 and 2004, respectively.

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.

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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.

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. Appeals have been filed by all parties and are currently pending before the Supreme Court in The Hague. 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. Based on the information known to date, the Company believes that Unocal suffered no damages

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in excess of the costs of production and that the Company will incur no liability in this matter other than the costs of litigation. The Company has not established a reserve for this matter since it currently does not believe that an unfavorable outcome is probable.

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 $57 million in principal, plus $417 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, and the parties are proceeding with pre-trial discovery. The trial of this matter is scheduled to commence in October 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, 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.

At June 30, 2005, the Company s Consolidated Balance Sheet included reserves for legal proceedings of $91 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 June 30, 2005 and December 31, 2004 was approximately $4,547 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.

	Second Quarter							
	2005				2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Revenues	$869	$594	$223	$1,686	$640	$507	$186	$1,333
Depreciation, depletion and amortization	110	162	44	316	84	128	51	263
Income before income taxes	539	287	115	941	376	246	72	694
Capital expenditures	$252	$178	$ 44	$ 474	$157	$107	$ 44	$ 308

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	Six Months							
	2005				2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Revenues	$1,616	$1,158	$488	$3,262	$1,254	$1,013	$374	$2,641
Depreciation, depletion and amortization	216	320	101	637	165	258	111	534
Income before income taxes	989	551	263	1,803	732	477	154	1,363
Capital expenditures	$ 412	$ 601	$ 68	$1,081	$ 336	$ 458	$ 77	$ 871

	June 30, 2005				December 31, 2004			
	U.S.	Canada	Intl	Total	U.S.	Canada	Intl	Total
	(In Millions)							
Properties-net	$4,170	$5,651	$1,380	$11,201	$3,984	$5,541	$1,417	$10,942
Goodwill	$	$1,035	$	$ 1,035	$	$1,054	$	$ 1,054

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

	Second Quarter		Six Months	
	2005	2004	2005	2004
	(In Millions)			
Income before income taxes for reportable segments	$941	$694	$1,803	$1,363
Corporate expenses	56	58	116	112
Interest expense	70	69	140	140
Other expense net	10	27	3	24
Consolidated income before income taxes	$805	$540	$1,544	$1,087

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

	Second Quarter		Six Months	
	2005	2004	2005	2004
	(In Millions)			
Total capital expenditures for reportable segments	$474	$308	$1,081	$871
Corporate properties net	2	7	4	12
Consolidated properties net	$476	$315	$1,085	$883

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

	June 30, 2005	December 31, 2004
	(In Millions)	
Properties net for reportable segments	$11,201	$10,942
Corporate properties net	81	91
Consolidated properties net	$11,282	$11,033

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8. ASSET RETIREMENT OBLIGATIONS

The Company s asset retirement obligations of $473 million at June 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 six months of 2005.

	(In Millions)
Carrying amount of asset retirement obligations as of December 31, 2004	$468
Liabilities settled during the period	(5)
Current period accretion expense	15
Changes in foreign exchange rates during the period	(5)
Carrying amount of asset retirement obligations as of June 30, 2005	$473

9. 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 six 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	(19)
Balance-June 30, 2005	$1,035

10. INCOME TAXES

The Company s effective income tax rate increased to 35 percent for the six months ended June 30, 2005 from 34 percent for the year ended December 31, 2004. The six months ended June 30, 2005 and the year ended December 31, 2004 included tax benefits of $9 million or 1 percent and $68 million or 3 percent, respectively, related to reductions in the Company s Canadian tax rates. The 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 to the U.S. during 2005 under the one-time provisions of the American Jobs Creation Act of 2004.

At June 30, 2005, $21 million of deferred income tax is classified as current and is included in Other Current Assets on the Consolidated Balance Sheet.

11. 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.

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

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

	Six Months			
	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In Millions)			
Benefit cost for the plans includes the following components				
Service cost	$ 6	$ 6	$	$
Interest cost	6	6	1	2
Expected return on plan asset	(6)	(6)		
Recognized net actuarial loss	2	2		
Net benefit cost	$ 8	$ 8	$1	$2

During the second quarter of 2005, the Company contributed $2 million to its pension plans. The Company expects to contribute a total of $12 million to its pension plans during 2005, of which $5 million remain unfunded as of June 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.

12. 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 six-month period ended June 30, 2005.

	(In Millions)
Balance at January 1, 2005	$ 23
Additions	42
Reclassifications to proved properties	(25)
Charged to expense	(5)
Balance at June 30, 2005	$ 35
Capitalized less than one year since completion of drilling	$ 35

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

13. 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 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.

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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. The Company continues to conduct repairs and audit the design of certain components of the Rivers Field natural gas processing plant in the United Kingdom (Rivers Field Plant). These activities are intended to address various construction and operational issues that occurred during commissioning and start-up of the plant. Future International production volumes will be impacted by the timing of the resumption of plant operations. The Company s current estimate for full year 2005 production volumes is expected to average between 2,820 and 2,985 MMCFE per day, which is virtually unchanged from estimates previously disclosed. This estimate does not include any production volumes from the Rivers Field Plant. The Company expects third quarter production volumes to average between 2,800 and 3,000 MMCFE per day.

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	0.60 to 0.64	0.57
Depreciation, depletion and amortization (DD&A)	1.20 to 1.30	1.10
Administrative	$ 0.17 to $0.20	$0.21
	(In Millions)	
Exploration costs	$ 310 to $335	$258
Interest expense	$ 270 to $290	$282

In 2005, the Company s operating costs are expected to increase about 5 to 12 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 decrease 5 to 19 percent from 2004 on a per unit-of-production basis as a result of expected lower stock-based compensation expense. 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 and the success it has in finding commercial hydrocarbons, which cannot be precisely forecasted. Therefore, it is difficult to 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 $72 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 $36 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. The Company s Board of Directors (Board) approved an increase in the Company s capital expenditures for 2005 to $2.4 billion, excluding acquisitions. Additionally, the Company recently closed transactions related to acquisitions of approximately $130 million. For more information on the Company s 2005 capital program, see the capital expenditures discussion on page 19 of this report.

Financial Condition and Liquidity

The Company s total debt to total capital (total capital is defined as total debt and stockholders equity) ratio at June 30, 2005 and December 31, 2004 was 34 percent and 36 percent, respectively. The improvement in this ratio was primarily attributable to the Company s strong 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 June 30, 2005, the Company had $2,385 million of cash and cash equivalents on hand, of which $1,686 million was located in Canada, $551 million in the U.S. and $148 million in International. The Company plans to repatriate $500 million of eligible foreign earnings to the U.S. during 2005 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 June 30, 2005, no debt securities had been redeemed, exchanged or repurchased under this authorization.

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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 held by the Company. On August 2, 2005, the Company entered into an Underwriting Agreement to sell 8,250,000 units for $15.45 per unit.

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. The Credit Facility expires in July 2009 unless extended. 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 June 30, 2005, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

Net cash provided by operating activities during the first six months of 2005 was $1,793 million, representing an increase of $249 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 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 $580 million. Crude oil and NGLs production volumes increased resulting in higher revenues of $68 million. Lower natural gas production volumes resulted in reduced revenues of $33 million. Working capital needs increased $12 million during the first six months of 2005 compared to the first six months of 2004.

Costs and expenses referred to in this discussion include operating costs, taxes other than income taxes, transportation expenses, and administrative expenses. These costs and expenses in the first six months of 2005 increased $96 million over the first six months of 2004. Operating costs and taxes other than income taxes represented the largest increase in these costs. 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 34 percent of the increase in costs and expenses compared to the first six months of 2004. 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 34 percent of the increase in costs and expenses compared to the first six months of 2004. Transportation expenses represented a 21 percent increase 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 six 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 again voted to restore the authorization level to $1 billion.

During the first six months of 2005, the Company repurchased approximately 9 million shares of its Common Stock for approximately $444 million and, as of June 30, 2005, had authority to repurchase an additional $508 million of its Common Stock under the current authorization.

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.

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

	Six Months 2005	Six Months 2004	Increase (Decrease)	% Increase (Decrease)
	($ In Millions)			
Oil and gas				
Development	$ 839	$604	$235	39%
Exploration	200	137	63	46
Acquisitions	21	84	(63)	(75)
Total oil and gas	1,060	825	235	28
Plants and pipelines	14	39	(25)	(64)
Administrative and other	11	19	(8)	(42)
Total capital expenditures	$1,085	$883	$202	23%

The Company s total capital expenditures during the first six months of 2005 increased 23 percent compared to the first six months of 2004. The Company utilizes a disciplined approach to capital spending. Excluding acquisitions, the Company s capital spending related to internal development and exploration increased 40 percent compared to the first six 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 to increase its capital expenditures in 2005, excluding proved property acquisitions, to approximately $2.4 billion, representing a 20 percent increase over previously announced expectations. 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.

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Dividends

On July 27, 2005, the Company s Board declared a quarterly common stock cash dividend of $0.10 per share, which represents an 18 percent increase over the previous quarterly dividend of $0.085 per share. The record and payment dates for the quarterly dividend are September 9, 2005 and October 11, 2005, respectively.

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 Second Quarter of 2005 Compared to Second Quarter of 2004

The Company reported net income of $537 million or $1.40 diluted earnings per common share in the second quarter of 2005 compared to net income of $379 million or $0.96 diluted earnings per common share in the second quarter of 2004.

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

Revenue Variances

	Second Quarter 2005	Second Quarter 2004	Increase	% Increase
	($ In Millions)			
Revenues				
Natural gas	$1,090	$ 932	$158	17%
NGLs	179	128	51	40
Crude oil	405	265	140	53
Processing and other	12	8	4	50
Total revenues	$1,686	$1,333	$353	26%

Price and Volume Variances

	Second Quarter 2005	Second Quarter 2004	Increase	% Increase	Increase (In Millions)
Price variance					
Natural gas sales prices (per MCF)	$ 6.28	$ 5.40	$ 0.88	16%	$ 153
NGLs sales prices (per Bbl)	29.62	23.81	5.81	24	35
Crude oil sales prices (per Bbl)	$46.71	$34.62	$12.09	35%	105
Total price variance					$ 293

	Second Quarter 2005	Second Quarter 2004	Increase	% Increase	Increase (In Millions)
Volume variance					
Natural gas sales volumes (MMCF per day)	1,909	1,899	10	1%	$ 5
NGLs sales volumes (MBbls per day)	66.6	59.0	7.6	13	17
Crude oil sales volumes (MBbls per day)	95.1	84.2	10.9	13%	34
Total volume variance					$ 56

Revenues

The Company s consolidated revenues increased $353 million in the second quarter of 2005 compared to the second quarter of 2004. Higher revenues were due primarily to higher commodity prices and sales volumes, resulting in increased revenues of $293 million and $56 million, respectively. 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 $293 million to the increase in revenues in the second quarter of 2005 compared to the second quarter of 2004. Average natural gas prices, including a $0.03 realized loss per MCF related to hedging activities, increased $0.88 per MCF during the second quarter of 2005 resulting in increased revenues of $153 million.

Average crude

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oil prices, including a $0.23 realized loss per barrel related to hedging activities, increased $12.09 per barrel in the second quarter of 2005, resulting in increased revenues of $105 million. Average NGLs prices increased $5.81 per barrel in the second quarter of 2005, resulting in higher revenues of $35 million.

Volume Variances

Sales volumes are another key driver that impact the Company s earnings and net operating cash flow generation. Higher sales volumes in the second quarter of 2005 resulted in increased revenues of $56 million compared to the second quarter of 2004. Average crude oil sales volumes increased 10.9 MBbls per day in the second quarter of 2005, resulting in increased revenues of $34 million. Crude oil sales volumes increased primarily due to higher production of 8.4 MBbls per day in the Cedar Creek Anticline, 4.3 MBbls per day in the Bakken Shale and 3.0 MBbls per day in Algeria partially offset by lower production of 4.2 MBbls per day in Ecuador. Average NGLs sales volumes increased 7.6 MBbls per day in the second quarter of 2005, resulting in higher revenues of $17 million compared to the same quarter last year. NGLs sales volumes increased primarily due to higher production of 5.2 MBbls per day in Canada. Average natural gas sales volumes increased 10 MMCF per day in the second quarter of 2005, resulting in higher revenues of $5 million. Average natural gas sales volumes increased due to higher production of 70 MMCF per day at Savell (Bossier) Field and 9 MMCF per day at Madden Field. These increases were partially offset by lower production volumes of 34 MMCF per day in the San Juan Basin, 16 MMCF per day at Millom and Dalton in the East Irish Sea, 13 MMCF per day from CLAM in the Dutch sector of the North Sea and 4 MMCF per day in Canada.

Below is a discussion of total costs and other expense net.

Total Costs and Other Expense Net

	Second Quarter		Increase	% Increase
	2005	2004	(Decrease)	(Decrease)
	($ In Millions)			
Costs and other expense net				
Taxes other than income taxes	$ 82	$ 62	$ 20	32%
Transportation expense	120	107	13	12
Operating costs	160	143	17	12
Depreciation, depletion and amortization	322	270	52	19
Exploration costs	67	62	5	8
Administrative	49	51	(2)	(4)
Interest expense	70	69	1	1
Loss on disposal of assets	1	2	(1)	(50)
Other expense net	10	27	(17)	(63)
Total costs and other expense net	$881	$793	$ 88	11%

Total costs and other expense net increased $88 million in the second quarter of 2005 compared to the second quarter of 2004. The increase in total costs and other expense - 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 costs and expenses in the future.

DD&A expense increased $52 million primarily due to asset additions with higher unit-of-production rates and higher foreign exchange rates. Taxes other than income taxes increased $20 million primarily due to higher severance taxes resulting from higher crude oil and natural gas revenues.

In general, operating costs are higher due to industry service cost pressures. Operating costs increased $17 million primarily due to higher well operating expenses related to well activity levels, foreign currency rates, maintenance and repairs and fuel and electricity expenses. Transportation expense increased $13 million primarily due to operations in International.

Exploration costs increased $5 million due to higher geological and geophysical (G&G) costs of $4 million and higher amortization of undeveloped lease costs and other expenses of $3 million partially offset by lower dry hole costs of $2 million. Exploration costs fluctuate from period to period primarily due to the amount the Company expends on its exploration capital program and its success rate; however, the success rate is difficult to predict. The current period exploration costs are not necessarily indicative of future costs.

The increases in costs and expenses described above were partially offset by lower other expense net of $17 million. Other expense net decreased primarily due to higher interest income and lower legal cost accruals partially offset by higher foreign currency exchange losses.

Income Tax Expense

Income tax expense increased $107 million in the second quarter of 2005 compared to the second quarter of 2004. The increase in income tax expense was primarily due to higher pretax income of $265 million. During the second quarter of 2005, the Company recorded a higher income tax expense of $11 million related to taxes on foreign income in excess of U.S. rates compared to the second quarter of 2004.

Results of Operations First Six Months of 2005 Compared to First Six Months of 2004

The Company reported net income of $1,008 million or $2.61 diluted earnings per common share in the first six months of 2005 compared to net income of $733 million or $1.85 diluted earnings per common share in the first six months of 2004.

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

Revenue Variances

	Six Months			%
	2005	2004	Increase	Increase
	($ In Millions)			
Revenues				
Natural gas	$2,097	$1,876	$221	12%
NGLs	354	262	92	35
Crude oil	789	487	302	62
Processing and other	22	16	6	38
Total revenues	$3,262	$2,641	$621	24%

Price and Volume Variances

	Six Months			%	Increase (In Millions)
	2005	2004	Increase	Increase	
Price variance					
Natural gas sales prices (per MCF)	$ 6.09	$ 5.35	$ 0.74	14%	$ 254
NGLs sales prices (per Bbl)	29.01	22.89	6.12	27	75
Crude oil sales prices (per Bbl)	$47.13	$32.12	$15.01	47%	251
Total price variance					$ 580

	Six Months		Increase	% Increase	Increase (Decrease) (In Millions)
	2005	2004	(Decrease)	(Decrease)	
Volume variance					
Natural gas sales volumes (MMCF per day)	1,903	1,926	(23)	(1)%	$ (33)
NGLs sales volumes (MBbls per day)	67.5	63.0	4.5	7	17
Crude oil sales volumes (MBbls per day)	92.5	83.3	9.2	11%	51
Total volume variance					$ 35

Revenues

The Company s consolidated revenues increased $621 million in the first six months of 2005 compared to the first six 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 $580 million and $68 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 $33 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 $580 million to the increase in revenues in the first six months of 2005 compared to the first six months of 2004. Average natural gas prices, including a $0.02 realized gain per MCF related to hedging activities, increased $0.74 per MCF during the first six months of 2005 resulting in increased revenues of $254 million. Average crude oil prices, including a $0.22 realized loss per barrel related to hedging activities, increased $15.01 per barrel in the first six months of 2005, resulting in increased revenues of $251 million. Average NGLs prices increased $6.12 per barrel in the first six months of 2005, resulting in higher revenues of $75 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 six months of 2005 resulted in increased revenues of $68 million compared to the first six months of 2004. Average crude oil sales volumes increased 9.2 MBbls per day in the first six months of 2005, resulting in increased revenues of $51 million. Crude oil sales volumes increased primarily due to higher production of 8.1 MBbls per day in the Cedar Creek Anticline and 3.7 MBbls per day in the Bakken Shale partially offset by lower production of 2.8 MBbls per day in Ecuador. Average NGLs sales volumes increased 4.5 MBbls per day in the first six 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 2.0 MBbls per day in Canada and 1.2 MBbls per day at the Waddell Ranch Field. Average natural gas sales volumes decreased 23 MMCF per day in the first six months of 2005, resulting in lower revenues of $34 million. Average natural gas sales volumes decreased primarily due to lower production of 28 MMCF per day in the San Juan Basin, 23 MMCF per day at Millom and Dalton in the East Irish Sea, 20 MMCF per day in Canada and 15 MMCF per day at CLAM in the Dutch sector of the North Sea. These decreases were partially offset by higher production volumes of 51 MMCF per day from the drilling programs at Savell (Bossier) Field and 16 MMCF per day at Madden Field.

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Below is a discussion of total costs and other expense net.

Total Costs and Other Expense Net

	Six Months 2005	Six Months 2004	Increase (Decrease)	% Increase (Decrease)
	($ In Millions)			
Costs and other expense net				
Taxes other than income taxes	$ 156	$ 121	$ 35	29%
Transportation expense	237	217	20	9
Operating costs	314	274	40	15
Depreciation, depletion and amortization	650	547	103	19
Exploration costs	118	122	(4)	(3)
Administrative	100	99	1	1
Interest expense	140	140		
Loss on disposal of assets		10	(10)	(100)
Other expense net	3	24	(21)	(88)
Total costs and other expense net	$1,718	$1,554	$164	11%

Total costs and other expense net increased $164 million in the first six months of 2005 compared to the first six months of 2004. The increase in total costs and other expense 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 costs and expenses in the future.

DD&A expense increased $103 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 $40 million primarily due to higher well operating expenses related to workovers, expenses related to timing of International oil sales, well activity levels, foreign currency rates, maintenance and repairs and fuel and electricity expenses.

Taxes other than income taxes increased $35 million primarily due to higher severance taxes resulting from higher crude oil and natural gas revenues. Transportation expense increased $20 million primarily due to operations in International.

The increases in costs and expenses described above were partially offset by lower other expense net of $21 million and lower exploration costs of $4 million. Other expense net decreased primarily due to higher interest income and lower legal cost accruals partially offset by higher foreign currency exchange losses. Exploration costs decreased due to lower dry hole costs of $16 million and lower drilling rig expenses of $5 million partially offset by higher G&G, delay rentals and other expenses of $12 million and higher amortization of undeveloped lease costs of $5 million. Exploration costs fluctuate from period to period primarily due to the amount the Company expends on its exploration capital program and its success rate; however, the success rate is difficult to predict. The current period exploration costs are not necessarily indicative of future costs.

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Income Tax Expense

Income tax expense increased $182 million in the first six months of 2005 compared to the first six months of 2004. The increase in income tax expense was primarily due to higher pretax income of $457 million. During the first six months of 2005, the Company recorded a higher income tax expense of $24 million related to taxes on foreign income in excess of U.S. rates compared to the first six months of 2004.

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.

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 June 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 $87 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 June 30, 2005, the Company expects to reclassify losses of $97 million ($61 million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At June 30, 2005, the Company had derivative assets of $2 million and derivative liabilities of $108 million, of which $2 million and $7 million are included in Other Current Assets and Other Liabilities and Deferred Credits, respectively, on the Consolidated Balance Sheet.

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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.

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)			
April 1, 2005 April 30, 2005	1,365	$50.19	1,365	$ 697,324
May 1, 2005 May 31, 2005	2,100	48.89	2,100	594,636
June 1, 2005 June 30, 2005	1,600	54.07	1,600	$ 508,118
Total	5,065	$50.88	5,065	

(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 again voted to restore the authorization level to $1 billion.

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ITEM 4. Submission of Matters to a Vote of Securities Holders

The Company s annual meeting of stockholders was held on April 27, 2005. The following were nominated and elected to serve as Directors of Burlington Resources Inc. for a term of one year or until their successors shall have been duly elected and qualified:

Nominee	For	Withheld
B. T. Alexander	343,894,979	4,990,474
R. V. Anderson	343,804,892	5,080,561
L. I. Grant	345,899,987	2,985,466
R. J. Harding	343,771,058	5,114,395
J. T. LaMacchia	344,228,186	4,657,267
R. L. Limbacher	340,142,664	8,742,789
J. F. McDonald	283,928,690	64,956,763
K. W. Orce	224,027,019	124,858,434
D. M. Roberts	340,144,116	8,741,337
J. A. Runde	345,673,616	3,211,837
J. F. Schwarz	345,818,520	3,066,933
W. Scott, Jr.	330,795,391	18,090,062
B. S. Shackouls	339,961,581	8,923,872
S. J. Shapiro	331,337,034	17,548,419
W. E. Wade, Jr.	345,700,615	3,184,838

In addition, at the annual meeting the Company s stockholders also ratified the appointment of PricewaterhouseCoopers LLP as independent auditor of the Company for the year ending December 31, 2005 with 338,859,449 votes for, 7,951,280 votes against and 2,074,724 votes abstaining. There were no broker non-votes with respect to any matters submitted to a vote of stockholders.

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	Amendment No. 4, effective July 28, 2005, to Burlington Resources Inc. 1997 Stock Option Incentive Plan
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 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: August 3, 2005

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Exhibit Index

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