MERCURY GENERAL CORP
Form 8-K
May 03, 2010

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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 3, 2010

MERCURY GENERAL CORPORATION

(Exact Name of Registrant as Specified in Charter)

California	001-12257	95-221-1612
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

4484 Wilshire Boulevard
Los Angeles, California 90010

(Address of Principal Executive Offices)

(323) 937-1060

(Registrant's telephone number, including area code)

Not applicable

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14.a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 1.01. Entry Into Material Definitive Agreement

On April 30, 2010, the Board of Directors of Mercury General Corporation (the “Company”) approved the form of Restricted Stock Agreement for grants of performance-based restricted stock awards under the Mercury General Corporation 2005 Equity Incentive Plan. The Restricted Stock Agreement is filed as Exhibit 10.1 hereto, and is incorporated herein by reference.

Item 2.02. Results of Operations and Financial Condition

The following information is furnished pursuant to Item 2.02, “Results of Operations and Financial Condition,” and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

On May 3, 2010, Mercury General Corporation issued a press release announcing its financial results for the first quarter ended March 31, 2010. A copy of the press release is attached hereto as Exhibit 99.1.

The information contained in this Current Report, including the exhibit, shall not be incorporated by reference into any filing of Mercury General Corporation, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

10.1 Form of Restricted Stock Agreement for grants of performance-based restricted stock awards under the Mercury General Corporation 2005 Equity Participation Plan.

99.1 Press Release, dated May 3, 2010, issued by Mercury General Corporation, furnished pursuant to Item 2.02 of Form 8-K.

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 hereunto duly authorized.

Date: May 3, 2010	MERCURY GENERAL CORPORATION
	By: /s/ Theodore Stalick
	Name: Theodore Stalick
	Its: Chief Financial Officer

Exhibit Index

Exhibit 10.1. Form of Restricted Stock Agreement for grants of performance-based restricted stock awards under the Mercury General Corporation 2005 Equity Participation Plan.

Exhibit 99.1. Press Release, dated May 3, 2010, issued by Mercury General Corporation.

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yle="font-size: 9pt;color: #000000; background: #ffffff; margin-top: 6pt; margin-left: 0; margin-right: 0; margin-bottom: 0; "> **Spacing** is the number of wells which conservation laws allow to be drilled on a given area of land.

Step-out drilling is drilling a well adjacent to a proven well but moving in the direction of an unproven area.

Swaps are contracts between two parties to exchange streams of variable and fixed prices on specified notional amounts. One party to the swap pays a fixed price while the other pays a variable price.

Sweet gas is natural gas free of significant amounts of hydrogen sulfide or carbon dioxide when produced.

Taxes other than income taxes include severance taxes, ad valorem taxes, franchise and payroll taxes.

Tight gas is natural gas produced from a formation with low permeability that will not give up its gas readily at high flow rates.

Transportation expense primarily includes costs to process, including payments made in-kind, and costs to transport crude oil, NGLs and natural gas to a major facility, market hub, sales point or plant.

Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.
Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover is the operations on a producing well to restore or increase production.
Writer refers to the seller of an option. The writer earns the premium on the option but bears the risk of fulfilling the obligations of the option.
Zone is a stratigraphic interval containing one or more reservoirs.

PART I

ITEMS ONE AND TWO

BUSINESS AND PROPERTIES

Burlington Resources Inc. (BR) is among the world s largest independent oil and gas companies and holds one of the industry s leading positions in North American natural gas reserves and production. BR conducts exploration, production and development operations in the U.S., Canada, the United Kingdom, the Netherlands, North Africa, China and South America. BR is a holding company and its principal subsidiaries include Burlington Resources Oil & Gas Company LP, The Louisiana Land and Exploration Company (LL&E), Burlington Resources Canada Ltd., Burlington Resources Canada (Hunter) Ltd. (formerly known as Canadian Hunter Exploration Ltd.) (Hunter), and their affiliated companies (collectively, the Company).

On December 12, 2005, BR and ConocoPhillips entered into a definitive agreement under which ConocoPhillips will acquire BR. Under the terms of the agreement, BR shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each BR share they own. The transaction is subject to approval by BR shareholders of record on February 24, 2006 and other customary terms and conditions. A special meeting of shareholders to vote on the proposed merger is March 30, 2006. Regulatory approvals have been granted and, upon approval by shareholders, the transaction is expected to close by March 31, 2006.

In December 2001, the Company consummated the acquisition of Hunter valued at approximately U.S. $2.1 billion, resulting in goodwill of approximately $793 million. The Hunter acquisition added a portfolio of properties, primarily located in the Western Canadian Sedimentary Basin, an area in which the Company already operated. The most significant of the assets is the Deep Basin, one of North America s largest natural gas fields.

The Company s reportable segments are the U.S., Canada and International. For financial information related to the Company s reportable segments, see Note 17 of Notes to Consolidated Financial Statements. The Company s worldwide major operating areas are discussed below.

North America

The Company s asset base is dominated by North American natural gas properties. Its extensive North American lease holdings extend from the U.S. Gulf Coast to Northeast British Columbia and Northern Alberta in Canada. The Company s North American operations include a mix of production, development and exploration assets.

Year Ended December 31, 2005	Worldwide	U.S.	U.S. s % of Worldwide	Canada	Canada s % of Worldwide
			($ In Millions)		
Oil and gas capital expenditures					
Development	$1,819	$ 795	44%	$ 897	49%
Exploration	467	189	40	246	53
Acquisitions proved	328	294	90	34	10
Total oil and gas capital expenditures	$2,614	$1,278	49%	$1,177	45%
Production					
Natural gas (MMCF per day)	1,905	950	50%	804	42%
NGLs (MBbls per day)	66.7	42.5	64	24.2	36

Crude oil (MBbls per day)	93.0	49.3	53%	6.0	6%
December 31, 2005					
Proved reserves (TCFE)	12.5	8.4	67%	3.0	24%

U.S.

San Juan Basin

The San Juan Basin, in northwest New Mexico and southwest Colorado, is one of the Company s major operating areas in terms of reserves and production. The San Juan Basin encompasses nearly 7,500 square miles, or approximately 4.8 million acres, with the major portion located in New Mexico s Rio Arriba and San Juan counties. The Company is a significant holder of productive leasehold and mineral acreage in this area with over 866,000 net acres under its control. The Company operates over 7,700 well completions in the San Juan Basin and holds interests in an additional 5,000 non-operated well completions.

In 2005, the Company invested $164 million in oil and gas capital, excluding acquisitions, drilled or participated in drilling 374 new wells and performed 134 workovers on existing wells. The Company s net production from the San Juan Basin averaged approximately 514 MMCF of natural gas per day, 31.3 MBbls of NGLs per day and 1.1 MBbls of crude oil per day during 2005.

Production from the San Juan Basin grew significantly during the 1990s, first as a result of Fruitland Coal drilling and then as a result of the development of tight gas formations. To mitigate Fruitland Coal production decline, the Company has an ongoing program that consists of drilling new wells, performing workovers on existing wells, adding compression, and installing artificial lift, where appropriate.

The Company continues to pursue development opportunities in the three conventional formations (Mesaverde, Pictured Cliffs and Dakota) in the San Juan Basin. The Mesaverde formation, which consists of the Lewis Shale, Cliffhouse, Menefee and Point Lookout sands, is the largest producing tight gas formation in the San Juan Basin. In 2005, the Company continued its ongoing infill drilling program in this formation. In 2005, the Company drilled or participated in drilling 226 conventional wells on 160-acre and 80-acre spacing. Net production from the tight gas producing formations averaged 327 MMCF of natural gas per day, 30.3 MBbls of NGLs per day and 1.1 MBbls of crude oil per day in 2005.

In the Fruitland Coal, the Company drilled or participated in drilling 148 wells on 320-acre and 160-acre spacing during 2005. In 2005, net production from the Fruitland Coal averaged 187 MMCF of natural gas per day and 1.0 MBbls of NGLs per day from over 2,100 completions.

On the Negro Canyon leasehold purchased in 2004, which is located in the heart of the Company s Fruitland Coal producing area, the Company drilled eight Fruitland Coal wells and one Dakota well in 2005 and expects to fully develop the remaining leases by the end of 2006. The Company owns a 100 percent working interest and an 87.5 percent net revenue interest in the 1,242 acre tract.

Wind River Basin

The Madden Field, located in the Wind River Basin, covers more than 70,000 acres in Wyoming s Fremont and Natrona counties. Net production averaged 127 MMCF of natural gas per day in 2005 from multiple horizons ranging in depth from 5,000 feet to over 25,000 feet, where the deep Madison formation occurs. Investments in the Wind River Basin during 2005 totaled $48 million for 65 newly drilled wells and workover projects. The Company owns an approximate 48 percent working interest in the Lost Cabin Gas Plant and net revenue interests varying from 22 to 40 percent in the producing reservoirs.

Williston Basin

The Williston Basin operations, located in western North Dakota and eastern Montana, were focused on activities on the Cedar Creek Anticline and in the Bakken Shale formation during 2005. Total Williston Basin production averaged 34.0 MBbls of crude oil per day and 11 MMCF of natural gas per day. During 2005, the Company invested $152 million on projects in the Williston Basin.

The Company continued its highly active waterflood development program with 160-acre infill drilling at both the Cedar Hills South and East Lookout Butte Units. A total of 43 production wells were drilled in the two units, along with the continued expansion of the injection and gathering infrastructure. In addition to the development drilling program on the Cedar Creek Anticline, drilling continued in the siltstone of the Bakken Shale formation where 34 wells were drilled in Richland County, Montana and two wells in McKenzie County, North Dakota. The Company currently controls over 98,000 net acres including areas in these two counties.

Anadarko Basin

The Anadarko Basin, located principally in western Oklahoma, encompasses over 30,000 square miles and contains some of the deepest producing formations in the world ranging in depth from 11,000 feet to over 21,000 feet. Net production for 2005 from the Anadarko Basin averaged 72 MMCF of natural gas per day and 2.0 MBbls of NGLs per day. During 2005, the Company invested $100 million in the Anadarko Basin. Operated activity focused on the Red Fork and Atoka formations in Roger Mills and Washita counties, Oklahoma, where the Company drilled 107 wells.

Permian Basin

Permian Basin operations, in west Texas, are focused on the Waddell Ranch Field. Total Permian Basin net production in 2005 averaged 12 MMCF of natural gas per day, 3.8 MBbls of crude oil per day and 2.6 MBbls of NGLs per day, with the Waddell Ranch Field contributing 8 MMCF of natural gas per day, 2.7 MBbls of crude oil per day and 2.5 MBbls of NGLs per day. During 2005, the Company invested

$7 million in the Permian Basin operations.

Fort Worth Basin

In the Fort Worth Basin of north central Texas, the Company continued to develop its Barnett Shale formation acreage in Denton and Wise counties, Texas. Additional acreage was also acquired during 2005 in mostly Johnson, Hood, Parker, and Palo Pinto counties, Texas. The Company now controls 102,000 net acres in the Fort Worth Basin. During 2005, the Company invested $137 million in this area, excluding acquisitions, and drilled 92 wells. Net production averaged 41 MMCF of natural gas per day, 4.4 MBbls of NGLs per day and 1.0 MBbls of crude oil per day in 2005.

Onshore Gulf Coast

The Onshore Gulf Coast includes operations in a number of drilling trends in east Texas, south Louisiana, the Onshore Gulf of Mexico and the Florida panhandle where the Company invested $344 million and drilled 70 wells. Net production in 2005 averaged 169 MMCF of natural gas per day, 9.0 MBbls of crude oil per day and 1.1 MBbls of NGLs per day.

In south Louisiana, the Company owns 660,000 net acres of fee lands with both surface and mineral rights. The Company spent $156 million of capital in south Louisiana during 2005 and drilled 43 wells. Net production in south Louisiana averaged 89 MMCF of natural gas per day, 6.6 MBbls of crude oil per day and 0.7 MBbls of NGLs per day in 2005.

In the Bossier trend, the Company controlled over 177,000 net acres at year end, and is expanding beyond its successful Savell Field development with other exploration and development activities along the trend. The Company spent $151 million of capital, drilled 18 wells, and had five operated rigs drilling at year end. In 2005, net production averaged 76 MMCF of natural gas per day in the Bossier.

Canada

Western Canadian Sedimentary Basin

In the Western Canadian Sedimentary Basin (Sedimentary Basin), the Company s portfolio of opportunities includes conventional exploration and development in Alberta, British Columbia and Saskatchewan. Canadian operations in 2005 were focused on expanding activity into large-scale, repeatable drilling programs in conventional and lower permeability reservoirs. Oil and gas capital investments in Canada were $1,143 million, excluding acquisitions, and 878 wells were drilled. Production in Canada was 804 MMCF of natural gas per day, 24.2 MBbls of NGLs per day and 6.0 MBbls of crude oil per day during 2005. The Company continued its resource assessment studies to identify future drilling opportunities across the Sedimentary Basin during 2005.

The Deep Basin area, in Alberta and British Columbia, consists of the Elmworth, Wapiti, Noel and Brassey Fields. In 2005, a $408 million oil and gas capital program was focused on exploration and development in the Deep Basin area. As a result, 254 wells were drilled and 241 MMCF of natural gas per day and 13.6 MBbls of NGLs per day were produced from this area.

In the Foothills area, which borders on the west side of the Deep Basin, $76 million of oil and gas capital spending was focused on exploration and development and production was 52 MMCF of natural gas per day. In 2005, 16 wells were drilled.

The O Chiese area, in central Alberta, yielded production of 150 MMCF of natural gas per day, 5.7 MBbls of NGLs per day and 2.4 MBbls of crude oil per day in 2005. The O Chiese area was the focus of a $205 million exploration and development program in 2005 that mostly targeted the Lower Cretaceous and Jurassic sands, the principal historical targets. In 2005, 144 wells were drilled.

In the Northern Plains, the Company continued exploration and development activities in the northern Alberta and British Columbia areas. Production in the Northern Plains during 2005 averaged 75 MMCF of natural gas per day and 2.2 MBbls of NGLs per day. A $79 million capital program targeted the Bluesky, Gething and Montney formations and 77 wells were drilled during 2005.

In the Kaybob area, production for the year averaged 122 MMCF of natural gas per day, 1.9 MBbls of NGLs per day and 0.9 MBbls of crude oil per day. The Company invested $249 million and drilled 131 wells in this area during 2005.

The Southern Plains area, which includes the Viking Kinsella property, produced approximately 156 MMCF of natural gas per day, 1.4 MBbls of crude oil per day and 0.8 MBbls of NGLs per day in 2005. In 2005, the Company invested $99 million and drilled 233 wells in the Southern Plains area.

International

The Company s International activities include a combination of exploration opportunities, large field developments, and production operations. Key focus areas are Northwest Europe, North Africa, China, and South America.

Year Ended December 31, 2005	Worldwide	International	% of Worldwide
		($ In Millions)	
Oil and gas capital expenditures			
Development	$1,819	$ 127	7%
Exploration	467	32	7
Acquisitions proved	328		
Total oil and gas capital expenditures	$2,614	$ 159	6%
Production			
Natural gas (MMCF per day)	1,905	151	8%
NGLs (MBbls per day)	66.7		
Crude oil (MBbls per day)	93.0	37.7	41%
December 31, 2005			
Proved reserves (TCFE)	12.5	1.1	9%

Northwest Europe

In the East Irish Sea, the Company has a 100 percent working interest in seven operated gas fields, including Millom and Dalton producing gas fields and the Rivers sour gas fields. Net production from the East Irish Sea averaged 68 MMCF of natural gas per day during 2005. The Company invested $23 million of capital in this area during the year. At the Rivers Fields, the Company continued the remedial work related to the onshore terminal and production is expected to resume during the first quarter of 2006. This facility is capable of reaching a peak sales rate of approximately 100 MMCF of natural gas per day.

During 2005, four wells were drilled in the East Irish Sea. One well in the Dalton Field found sub-commercial quantities of gas and was plugged and abandoned. Three other wells, on the Kelly, Darwen East and Asland North prospects failed to encounter gas in commercial quantities and were also plugged and abandoned.

The Company s Northwest European shelf investments also consist of non-operated production from its wholly-owned Netherlands affiliate in the Dutch sector of the North Sea. In 2005, the Netherlands affiliate CLAM was renamed Burlington Resources Nederland Petroleum B.V. (BRN). The BRN assets yielded an average production rate of 57 MMCF of natural gas per day during the year. BRN also owns an interest in an exploration license in Denmark. License 01/04 in the Danish sector comprises 11 blocks or partial blocks. The Company holds a 40 percent interest in the blocks. In 2005, a total of 2,077 kilometers of 2D seismic was acquired by DONG, the operator of the blocks.

North Africa

In North Africa, the Company continued progress in its development programs in both Algeria and Egypt and approved plans for future developments in both locations. The Company s capital investments in North Africa during 2005 totaled $49 million.

In Algeria, at the Menzel Lejmat North (MLN) Field on Block 405a, where the Company operates and has a 65 percent working interest, net production averaged 11.8 MBbls of crude oil per day. During 2005, the Company approved the MLN Expansion Project which is expected to increase field production and reserves through additional pressure maintenance. One development well was drilled in the area in 2005.

The Ourhoud Field, where the Company has a 3.7 percent working interest, produced at an average net rate of 4.8 MBbls of crude oil per day in 2005. Six development wells, two injection wells and one water-source well were drilled during 2005, and the waterflood development of this large crude oil field was continued.

Development of oil reserves in the southern MLSE area of Block 405a progressed with partners agreeing to form the EMK oil field unit where the Company currently has a minority interest in the unit. The partners have initiated engineering studies and drilling activities with the expectation of finalizing the development plan for the field in 2006. Capital spending in 2005 was $4 million and two wells were drilled.

In Egypt, where the Company has a 50 percent non-operated working interest in the Offshore North Sinai concession, development of the Tao Gas Field was approved by the Company during 2005. Detailed engineering studies are under way for the facilities and pipelines, and plans are being developed to commence drilling in 2006.

China

In the Far East, the Company continued its focus on selected basins in China. The Company entered its second full year of production at the Panyu Field in the South China Sea and continued to pursue the first phase of its development plan for its onshore gas development in the Sichuan Basin. The Company made capital investments of $53 million in China in 2005.

The Panyu development involves two offshore oil fields, Bootes and Ursa, located in Block 15/34 in the Pearl River Mouth Basin. The Company holds a 24.5 percent working interest in this asset. During 2005, the second phase of the development drilling program was initiated. Government sanctioning was also received and work commenced on a $5 million facilities upgrade to handle the additional fluid volumes expected. In addition, the plan of development was submitted to the government for the PY 11-6 discovery which will be produced from the Bootes platform. In 2005, average net production was 15.1 MBbls of crude oil per day.

Onshore, the Company holds a 100 percent working interest in a natural gas project in the Chuanzhong Block in the Sichuan Basin. The project represents an opportunity to apply the Company s expertise in the development of tight gas sand reservoirs. During 2005, the Company increased its net production from 4 MMCF of natural gas per day to 8 MMCF of natural gas per day. Average annual net production in 2005 was 6 MMCF of natural gas per day.

South America

The Company s efforts in South America during 2005 were concentrated on expanding near-term production potential and enhancing long-term exploration opportunities. Net production from South America averaged 5.9 MBbls of crude oil per day and 21 MMCF of natural gas per day. The Company invested $38 million of capital in South America during the year.

In Ecuador, the Company holds a 30 percent working interest in Block 7 and a 37.5 percent working interest in Block 21. Development of the Yuralpa Field in Block 21 continues where 11 wells were drilled during 2005. Net production from Block 21 averaged 3.3 MBbls of crude oil per day. In Block 7, six wells were successfully drilled during the year. Net production from Block 7 was 2.5 MBbls of crude oil per day. The Company s capital investments in 2005 totaled $26 million for projects in Ecuador.

In Argentina, the Company holds a 25.7 percent working interest in the Sierra Chata concession in the Neuquen Basin. Three development wells were drilled during 2005. Net production averaged 21 MMCF of natural gas per day in 2005 and capital investments in Argentina totaled $2 million.

In Peru, the Company holds a 45 percent working interest in Block 39 and operates Block 104 in the Marañon Basin with a 100 percent working interest. The Company participated in a discovery on Block 39 with the drilling of the Buena Vista #1 well which tested a gross 2.5 MBbls of crude oil per day from two zones. Additional drilling is expected to determine whether there are sufficient reserves in the area to allow commercial development to proceed. The Company also holds a 23.9 percent working interest in Blocks 57 and 90 located in the Ucayali Basin. The Company s capital investments in Peru totaled $9 million during 2005.

In Colombia, the Company holds an exploration contract for a 100 percent working interest in the Orquídea area of the Middle Magdalena Basin.

Productive Wells
Working interests in productive wells follow.

Year Ended December 31, 2005	**Gross**	**Net**
North America		
U.S.		
Natural gas	12,326	7,042
Crude oil	2,712	1,293
Canada		
Natural gas	6,308	4,897
Crude oil	1,078	547
International		
Natural gas	207	67
Crude oil	205	57
Worldwide		
Natural gas	18,841	12,006
Crude oil	3,995	1,897
Total Worldwide	22,836	13,903

Net Wells Drilled
The following table sets forth the Company s net productive and dry wells.

Year Ended December 31,	**2005**	**2004**	**2003**
North America			
U.S.			
Productive			
Exploratory	13.5	3.9	0.9
Development	393.2	331.3	399.0
Dry			
Exploratory	5.1	4.5	2.5
Development	11.7	4.0	5.3
Total U.S.	423.5	343.7	407.7
Canada			
Productive			
Exploratory	85.0	32.6	102.5
Development	506.5	395.4	384.4
Dry			
Exploratory	29.7	25.0	48.6
Development	51.7	27.2	57.6
Total Canada	672.9	480.2	593.1

International			
Productive			
Exploratory	0.5	2.0	0.7
Development	13.0	8.5	10.9
Dry			
Exploratory	5.0	3.1	1.8
Development	1.0		1.0
Total International	19.5	13.6	14.4
Worldwide			
Productive			
Exploratory	99.0	38.5	104.1
Development	912.7	735.2	794.3
Dry			
Exploratory	39.8	32.6	52.9
Development	64.4	31.2	63.9
Total Worldwide	1,115.9	837.5	1,015.2

As of December 31, 2005, 380 gross wells, representing approximately 281 net wells, were being drilled or awaiting completion with 67 percent and 31 percent of these wells located in Canada and the U.S., respectively.

Acreage
Working interests in developed and undeveloped acreage follow.

December 31, 2005	Gross	Net
North America		
U.S.		
Developed Acreage	4,658,680	2,661,973
Undeveloped Acreage	9,586,087	8,106,349
Canada		
Developed Acreage	3,670,010	2,463,999
Undeveloped Acreage	4,638,729	3,133,984
International		
Developed Acreage	719,389	235,092
Undeveloped Acreage	12,978,084	6,829,801
Worldwide		
Developed Acreage	9,048,079	5,361,064
Undeveloped Acreage	27,202,900	18,070,134
Total Worldwide	36,250,979	23,431,198

Capital Expenditures
The Company s capital expenditures follow.

Year Ended December 31,	2005	2004	2003
		(In Millions)	
North America			
U.S.			
Oil and Gas Activities	$1,278	$ 712	$ 540
Plants and Pipelines	3	3	5
Administrative and Other	14	24	23
Total U.S.	1,295	739	568
Canada			
Oil and Gas Activities	1,177	802	679
Plants and Pipelines	27	31	19
Administrative and Other	13	9	17
Total Canada	1,217	842	715
International			
Oil and Gas Activities	159	130	366
Plants and Pipelines	14	32	139
Administrative and Other	2	4	

Total International	175	166	505
Worldwide			
Oil and Gas Activities	2,614	1,644	1,585
Plants and Pipelines	44	66	163
Administrative and Other	29	37	40
Total Worldwide	$2,687	$1,747	$1,788

In 2005, worldwide capital expenditures related to oil and gas activities were $2,614 million and included 70 percent associated with development, 18 percent for exploration and 12 percent for proved property acquisitions. Exploration costs expensed under the successful efforts method of accounting are included in capital expenditures for oil and gas activities.

Oil and Gas Production and Prices

The Company s average daily production represents its net ownership and includes royalty interests and net profit interests owned by the Company. The Company s average daily production and average sales prices follow.

Year Ended December 31,	**2005**	**2004**	**2003**
North America			
U.S.			
Production			
Natural gas (MMCF per day)	950	908	865
NGLs (MBbls per day)	42.5	41.7	37.4
Crude oil (MBbls per day)	49.3	37.2	29.3
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 7.27	$ 5.54	$ 4.87
Natural gas, (gain) loss on hedging (per MCF)	0.26	(0.02)	0.10
Natural gas, excluding hedging (per MCF)	7.53	5.52	4.97
NGLs (per Bbl)	28.45	22.87	18.42
Crude oil, including hedging (per Bbl)	50.39	36.31	28.08
Crude oil, loss on hedging (per Bbl)	1.50	2.28	0.14
Crude oil, excluding hedging (per Bbl)	$51.89	$38.59	$28.22
Canada			
Production			
Natural gas (MMCF per day)	804	819	867
NGLs (MBbls per day)	24.2	23.6	27.4
Crude oil (MBbls per day)	6.0	5.5	5.1
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 7.54	$ 5.85	$ 5.12
Natural gas, loss on hedging (per MCF)	0.23	0.05	0.10
Natural gas, excluding hedging (per MCF)	7.77	5.90	5.22
NGLs (per Bbl)	40.68	29.79	23.08
Crude oil (per Bbl)	$52.20	$37.70	$31.11
International			
Production			
Natural gas (MMCF per day)	151	187	167
Crude oil (MBbls per day)	37.7	42.5	12.1
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 5.16	$ 3.64	$ 3.07
Natural gas, loss on hedging (per MCF)	0.07		
Natural gas, excluding hedging (per MCF)	5.23	3.64	3.07
Crude oil (per Bbl)	$51.10	$35.94	$23.49
Worldwide			
Production			

Natural gas (MMCF per day)	1,905	1,914	1,899
NGLs (MBbls per day)	66.7	65.3	64.8
Crude oil (MBbls per day)	93.0	85.2	46.5
Average Sales Price			
Natural gas, including hedging (per MCF)	$ 7.22	$ 5.49	$ 4.83
Natural gas, loss on hedging (per MCF)	0.23	0.01	0.09
Natural gas, excluding hedging (per MCF)	7.45	5.50	4.92
NGLs (per Bbl)	32.88	25.38	20.40
Crude oil, including hedging (per Bbl)	50.77	36.25	27.22
Crude oil, loss on hedging (per Bbl)	0.80	0.99	0.09
Crude oil, excluding hedging (per Bbl)	$51.57	$37.24	$27.31

Production Unit Costs

The Company s production unit costs follow. Production costs include production taxes and well operating costs.

Year Ended December 31,	2005	2004	2003
		(Per MCFE)	
North America			
U.S.			
Average Production Costs	$0.98	$0.80	$0.68
Average Production Taxes	0.55	0.42	0.34
DD&A Rates	0.76	0.68	0.62
Canada			
Average Production Costs	0.60	0.55	0.44
Average Production Taxes	0.05	0.04	0.03
DD&A Rates	1.73	1.41	1.19
International			
Average Production Costs	0.83	0.60	0.53
Average Production Taxes	0.11	0.09	0.01
DD&A Rates	1.45	1.32	1.14
Worldwide			
Average Production Costs	0.83	0.68	0.57
Average Production Taxes	0.32	0.23	0.18
DD&A Rates	$1.18	$1.04	$0.91

Reserves

The following table sets forth estimates by the Company s petroleum engineers of proved natural gas, NGLs and crude oil reserves at December 31, 2005. These reserves have been prepared in accordance with the Securities and Exchange Commission s Regulations. These reserves have been reduced for royalty interests owned by others.

December 31, 2005	Proved Developed	Proved Undeveloped	Total Proved Reserves
North America			
U.S.			
Natural gas (BCF)	3,752	1,523	5,275
NGLs (MMBbls)	221.4	109.4	330.8
Crude oil (MMBbls)	172.0	13.8	185.8
Total U.S. (BCFE)	6,113	2,262	8,375
Canada			
Natural gas (BCF)	1,956	583	2,539
NGLs (MMBbls)	45.1	12.6	57.7
Crude oil (MMBbls)	13.3	2.9	16.2
Total Canada (BCFE)	2,306	676	2,982
International			

Natural gas (BCF)	398	296	694
Crude oil (MMBbls)	42.5	29.7	72.2
Total International (BCFE)	653	474	1,127
Worldwide			
Natural gas (BCF)	6,106	2,402	8,508
NGLs (MMBbls)	266.5	122.0	388.5
Crude oil (MMBbls)	227.8	46.4	274.2
Total Worldwide (BCFE)	9,072	3,412	12,484

Miller and Lents, Ltd. and Sproule Associates Limited, independent oil and gas consultants, have reviewed the estimates of proved reserves of natural gas, crude oil and NGLs that the Company attributed to its net interests in oil and gas properties as of December 31, 2005. Miller and Lents, Ltd. reviewed the reserve estimates for the Company s U.S. and International interests and Sproule Associates Limited reviewed the Company s interests in Canada. Based on their review of more than 80 percent of the Company s reserve estimates, it is their judgment that the estimates are reasonable in the aggregate. For more information, see independent oil and gas consultants letters on pages 68-72.

For further information on reserves, including information on future net cash flows and the standardized measure of discounted future net cash flows, see Supplementary Financial Information Supplemental Oil and Gas Disclosures.

Other Matters

Regulation of Oil and Gas Production, Sales and Transportation The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments throughout the world. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which the Company operates also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

The Company operates various gathering systems. The United States Department of Transportation and certain governmental agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities by prescribing standards. However, based on current standards concerning transportation and storage activities and any proposed or contemplated standards, the Company believes that the impact of such standards is not material to the Company s operations, capital expenditures or financial position. Compliance with such standards has been incorporated by the Company in its operations over many years and no material capital expenditures are allocated to such compliance.

All of the Company s sales of its domestic natural gas are currently deregulated, although governmental agencies may elect in the future to regulate certain sales.

Environmental Regulation Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect the Company s domestic exploration, development and production operations and the costs of those operations. In addition, the Company s international operations are subject to environmental regulations administered by foreign governments, including political subdivisions thereof, or by international organizations. These domestic and international laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance under the Oil Pollution Act of 1990 and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from the Company s operations and may require the suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to the Company and its operations include, among others, the following United States federal laws and regulations:

Clean Air Act, and its amendments, which governs air emissions;

Clean Water Act, which governs discharges to waters of the United States;

Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as Superfund);

Resource Conservation and Recovery Act, which governs the management of solid waste;

Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;

Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;

Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and

U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

In addition, many states and foreign countries where the Company operates have similar environmental laws and regulations covering the same types of matters. In Canada, environmental compliance is governed by various statutes, regulations and codes promulgated at different levels of government including the federal Fisheries Act and Canadian Environmental Protection Act; and provincially, the Environmental Protection and Enhancement Act, the Oil and Gas Conservation Act and the Pipeline Act in the province of Alberta; and the Waste Management Act, the Environmental Assessment Act and the Environment Management Act in the province of British Columbia. The Kyoto Protocol to the United Nations Framework Convention on Climate Change (Kyoto Protocol) became effective February 16, 2005, and requires Annex I countries, including Canada and the United Kingdom, to reduce their emissions of carbon dioxide and other greenhouse gases. As a result of the ratification of the Kyoto Protocol and the adoption of legislation or other regulatory initiatives designed to implement its objectives by the national and regional governments, reductions in greenhouse gases from crude oil and natural gas producers may be required which could result in, among other things, increased operating and capital expenditures for those producers. Until such legislation or other regulatory initiatives are finalized, the impact of the Kyoto Protocol and any such legislation adopted as a result of its ratification remains uncertain.

The Company routinely obtains permits for its facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of the Company s facilities or operations.

The ultimate financial impact of these environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on the Company s operations in the United States and in most countries in which it operates. In addition, any non-compliance with such laws could subject the Company to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of the Company s ongoing operations and not an extraordinary cost of compliance with government regulations.

The Company is committed to the protection of the environment throughout its operations and believes that it is in substantial compliance with applicable environmental laws and regulations. The Company believes that environmental stewardship is an important part of its daily business and will continue to make expenditures on a regular basis relating to environmental compliance. The Company maintains insurance coverage for spills, pollution and certain other environmental risks, although it is not fully insured against all such risks. The insurance coverage maintained by the Company provides for the reimbursement to the Company of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of the Company s operations, but such insurance does not fully insure pollution and similar environmental risks. The Company does not anticipate that it will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on the consolidated financial position or results of operations of the Company. However, since environmental costs and liabilities are inherent in the Company s operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Filings of Reserve Estimates With Other Agencies During 2005, the Company filed estimates of its oil and gas reserves for the year 2004 with the Department of Energy. These estimates differ by 5 percent or less from the reserve data presented. For information concerning proved natural gas, NGLs and crude oil reserves, see Supplementary Financial Information Supplemental Oil and Gas Disclosures.

Employees

The Company had 2,416 and 2,214 employees at December 31, 2005 and 2004, respectively. At December 31, 2005, the Company had no union employees.

Web Site Access to Reports

The Company s Web site address is **www.br-inc.com**. The Company makes available, free of charge on or through its Web site, its annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission. Such reports, which include the Company s annual and quarterly financial statements, are also filed in Canada on the System for Electronic Document Analysis and Retrieval (SEDAR) and are also available to the Company s stockholders, including those residing in Ontario, Canada, from the Company upon request at no charge.

ITEM ONE A

RISK FACTORS

Business Uncertainties and Contractual Restrictions While Merger is Pending Uncertainty about the effect of the merger on employees, suppliers, partners, regulators and customers may have an adverse effect on BR. These uncertainties may impair BR s ability to attract, retain and motivate key personnel until the merger is consummated, and could cause suppliers, customers and others that deal with BR to defer purchases or other decisions concerning BR, or seek to change existing business relationships with BR. Employee retention may be particularly challenging while the merger is pending, as employees may experience uncertainty about their future roles with ConocoPhillips. In addition, the merger agreement restricts BR from making certain acquisitions and taking other specified actions without ConocoPhillips approval. These restrictions could prevent BR from pursuing attractive business opportunities that may arise prior to the completion of the merger.

Failure to Complete Merger Could Negatively Impact Stock Price, Future Business and Financial Results Although BR has agreed that its board of directors will, subject to fiduciary exceptions, recommend that its stockholders approve and adopt the merger agreement, there is no assurance that the merger agreement and the merger will be approved, and there is no assurance that the other conditions to the completion of the merger will be satisfied. If the merger is not completed, BR will be subject to several risks, including the following:

BR may be required to pay ConocoPhillips a termination fee of $1 billion in the aggregate if the merger agreement is terminated under certain circumstances and BR enters into or completes an alternative transaction;

The current market price of BR common stock may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a negative perception by the stock market of BR generally and a resulting decline in the market price of BR common stock;

Certain costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by BR whether or not the merger is completed;

There may be substantial disruption to the business of BR and a distraction of its management and employees from day-to-day operations, because matters related to the merger (including integration planning) may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to BR;

BR s business could be adversely affected if it is unable to retain key employees or attract qualified replacements; and

BR would continue to face the risks that it currently faces as an independent company.

Changes in Commodity Prices Could Have a Significant Adverse Effect on Financial Results, Impact the Company s Determination of Proved Reserves and Result in the Company Recognizing an Impairment Changes in natural gas, NGLs and crude oil prices (including basis differentials) from those assumed in preparing projections and forward-looking statements could cause the Company s actual financial results to differ materially from projected financial results and could also impact the Company s determination of proved reserves and the standardized measure of discounted future net cash flows relative to natural gas, NGLs and crude oil reserves. In addition, periods of sharply lower commodity prices could affect the Company s production levels, could cause it to curtail capital spending projects and delay or defer exploration, exploitation or development projects, could render productive wells non-commercial earlier than in a higher price environment and could result in the Company recognizing for Generally Accepted Accounting Principles purposes an impairment of unamortized capital costs.

Projections relating to the price received by the Company for natural gas and NGLs also rely on assumptions regarding the availability and pricing of transportation to the Company s key markets. In particular, the Company has contractual arrangements for the transportation of natural gas from the San Juan Basin eastward to Eastern and Midwestern markets or to market hubs in Texas, Oklahoma and Louisiana. The natural gas price received by the Company could be adversely affected by any constraints in pipeline capacity to serve these markets. These and other commodity price risks that could cause actual results to differ from projections and forward-looking statements are further described in Part II, Qualitative and Quantitative Disclosure About Market Risk-Commodity Risk.

Risks and Uncertainties Normally Associated with the Exploration for and Development and Production of Natural Gas Could Significantly Impact the Company s Operations and Financial Results The Company s business is subject to all of the risks and uncertainties normally associated with the exploration for and development and production of natural gas, NGLs and crude oil, including uncertainties as to the presence, size and recoverability of hydrocarbons. The exploration for natural gas and crude oil is a high-risk business in which significant numbers of dry holes, completion and production difficulties and high associated costs can be incurred in the process of seeking commercial discoveries and placing them on production.

The process of estimating quantities of proved reserves is inherently uncertain and requires making subjective engineering, geological, geophysical and economic assumptions. In this regard, changes in the economic conditions (including commodity prices) or operating conditions (including, without limitation, exploration, development and production costs and expenses and drilling and production results from exploration and development activity) could cause the Company s estimated proved reserves or production to differ from those included in any such forward-looking statements or projections. Reserves which require the use of improved recovery techniques for production are included in proved reserves if supported by a suitable analogy, a successful pilot project or the operation of an installed program. There are many risks inherent in developing and implementing improved recovery techniques which can cause a pilot project to be unsuccessful.

In addition, the Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment as well as to dismantle and abandon plants at the end of oil and gas production operations. Estimating the costs of these obligations requires management to make estimates and judgments regarding timing, existence of a liability as well as what constitutes adequate restoration. Increases in the estimated costs of decommissioning and abandoning a proved property or production facilities above previously forecasted levels could cause the Company s estimated proved reserves to decrease from those included in forward-looking statements.

Projecting future natural gas, NGLs and crude oil production is imprecise. Producing oil and gas reservoirs eventually have declining production rates. Projections of production rates rely on certain assumptions regarding historical production patterns in the area or formation tests for a particular producing horizon. Actual production rates could differ materially from such projections. Production rates depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate. In addition, Organization of Petroleum Exporting Countries in which the Company has producing properties, such as Algeria, could subject the Company to periods of curtailed production due to governmental mandated cutbacks when world oil market demand is weak.

Another major factor affecting the Company s production is its ability to replace depleting reservoirs with new reserves through acquisition, exploration or development programs. Exploration success is extremely difficult to predict with certainty, particularly over the short term where the timing and extent of successful results vary widely. Over the long term, the ability to replace reserves depends not only on the Company s ability to locate crude oil, NGLs and natural gas reserves, but on the cost of finding and developing such reserves. Moreover, development of any particular exploration or development project may not be justified because of the commodity price environment at the time or because of the Company s finding and development costs for such project. No assurances can be given as to the level or timing of success that the Company will be able to achieve in acquiring or finding and developing additional reserves.

Projections relating to the Company s production and financial results rely on certain assumptions about the Company s continued success in its acquisition and asset rationalization programs and in its cost management efforts.

The Company s drilling operations are subject to various hazards common to the oil and gas industry, including weather conditions, explosions, fires, and blowouts, which could result in damage to or destruction of oil and gas wells or formations, production facilities and other property and injury to people. They are also subject to the additional hazards of marine operations, such as capsizing, collision and damage or loss from severe weather conditions.

Concentration Risk for Natural Gas Transportation Because the Company transports a significant amount of its natural gas production through a limited number of pipeline systems, mechanical failure or regulatory action at certain points on these pipeline systems could result in a substantial interruption of the transportation of the Company s natural gas production for a limited period of time pending the Company securing alternate transportation arrangements.

Assumptions Used in Valuing Goodwill Are Inherently Unpredictable and Uncertain and Revisions to Estimates Could Lead to an Impairment in Future Periods The Company accounts for goodwill in accordance with Statement of Financial Accounting Standards No. 142, *Goodwill and other Intangible Assets*, and is required to make an annual impairment assessment in lieu of periodic amortization. The impairment assessment requires the Company to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. Although the Company bases its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar or depressed natural gas, NGLs and crude oil prices could lead to an impairment of goodwill in future periods.

Numerous Factors Affecting the Timing and Outcome of Projects Could Have a Significant Adverse Impact on the Company s Development Plan A significant portion of the Company s development plans involve large projects in Canada, Algeria, the East Irish Sea, China, Ecuador, Wyoming, North Dakota and other areas. A variety of factors affect the timing and outcome of such projects including, without limitation, approval by the other parties owning working interests in the project, receipt of necessary permits and approvals by applicable governmental agencies, access to surface locations and facilities, opposition by non-government organizations and local indigenous communities, the availability, costs and performance of the necessary drilling equipment and infrastructure, drilling risks, operating hazards, unexpected cost increases and technical difficulties in constructing, modifying and operating equipment, plants and facilities, manufacturing and delivery schedules for critical equipment and arrangements for the gathering and transportation of the produced hydrocarbons.

The Company s International Operations Are Subject to Risks Which May Adversely Affect the Company s Operations The Company s operations outside of the U.S. are subject to risks inherent in foreign operations, including, without limitation, the loss of revenue, property and equipment from hazards such as expropriation, nationalization, war, insurrection, acts of terrorism and other political risks, increases in taxes and governmental royalties, renegotiation or abrogation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations, world economic cycles, restrictions or quotas on production and commodity sales, limited market access and other uncertainties arising out of foreign government sovereignty over the Company s international operations. Laws and policies of the U.S. affecting foreign trade and taxation may also adversely affect the Company s international operations.

The Company s ability to market natural gas, NGLs and crude oil discovered or produced in its foreign operations, and the price the Company could obtain for such production, depends on many factors beyond the Company s control, including ready markets for natural gas, NGLs and crude oil, the proximity and capacity of pipelines and other transportation facilities, fluctuating demand for crude oil and natural gas, the availability and cost of competing fuels, and the effects of foreign governmental regulation of oil and gas production and sales. Pipeline and processing facilities do not exist in certain areas of exploration and, therefore, any actual sales of the Company s production could be delayed for extended periods of time until such facilities are constructed.

Competition in the Crude Oil and Natural Gas Industry is Intense; the Company Competes with Companies with Substantially Larger Financial and Other Resources The Company actively competes for property acquisitions, exploration leases and sales of natural gas, NGLs and crude oil, frequently against companies with substantially larger financial and other resources. In its marketing activities, the Company competes with numerous companies for gas purchasing and processing contracts and for natural gas and NGLs at several stages in the distribution chain. Competitive factors in the Company s business include price, contract terms, quality of service, pipeline access, transportation discounts and distribution efficiencies.

Foreign, National, State and Local Laws and Regulations Could Negatively Impact the Company s Operations or Financial Results The Company s operations are affected by foreign, national, state and local laws and regulations. Compliance with these regulations is often difficult and costly and non-compliance could subject the Company to material administrative, civil or criminal penalties, or other liabilities. Restrictions on production, price or gathering rate controls, changes in taxes, royalties and other amounts payable to governments or governmental agencies and other changes in or litigation arising under laws and regulations, or interpretations thereof, could have a significant effect on the Company s operations or financial results. The Company s operations in some geographic areas may be negatively impacted by legal proceedings, the actions of national, state and local governments, and the actions of non-governmental organizations that delay, restrict or prevent the Company s access to surface locations for natural gas and crude oil exploration and production activities. The Company s operations also may be negatively impacted by laws, regulations and legal proceedings pertaining to the valuation and measurement of natural gas, crude oil and NGLs and payment of royalties from such sales. Existing litigation involving the valuation and measurement of natural gas, crude oil and NGLs and payment of royalties from such sales is described in Note 14 of the Notes to Consolidated Financial Statements. Other legal and regulatory risks that could cause actual results to differ from projections and other forward-looking statements are described in Part I, Other Matters.

Political and Security Risk Could Have a Significant Adverse Effect on the Company s Operations or Financial Results Domestic and international political and security risks, including changes in government, seizure of property, civil unrest, armed hostilities and acts of terrorism, could have a significant effect on the Company s operations or financial results. Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as the military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and other geopolitical hostilities could adversely affect production or the market prices in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in crude oil and natural gas prices, or the possibility that the infrastructure on which the Company or operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

Various Regulations Relating to the Protection of the Environment May Significantly Affect the Company s Exploration, Development and Production, Including the Cost of Operations, and Could Result in Substantial Liabilities for Noncompliance or Suspension of Operations in Affected Areas The Company s operations are subject to various foreign, national, state and local laws and regulations covering the discharge of material into, and protection of, the environment. Such regulations and liability for remedial actions under environmental regulations affect the costs of planning, designing, operating and abandoning facilities. The Company expends considerable resources, both financial and managerial, to comply with environmental regulations and permitting requirements. Although the Company believes that its operations and facilities are in substantial compliance with applicable environmental laws and regulations, risks of substantial costs and liabilities are inherent in crude oil and natural gas operations. Moreover, it is possible that other developments, such as increasingly strict environmental laws, regulations and enforcement, and claims for damage to property or persons resulting from the Company s current or discontinued operations, could result in substantial costs and liabilities in the future.

While the Company maintains insurance coverage for spills, pollutions and certain other environmental risks, it is not fully insured against all such risks. Because regulatory requirements frequently change and may become more stringent, and environmental costs and liabilities are inherent in the Company s operations, there can be no assurance that material costs and liabilities will not be incurred in the future or that the Company s insurance will be sufficient to cover any such costs or liabilities. Such costs may result in increased costs of operations and acquisitions and decrease production.

ITEM ONE B

UNRESOLVED STAFF COMMENTS

None

ITEM THREE

LEGAL PROCEEDINGS

See Note 14 of Notes to Consolidated Financial Statements.

ITEM FOUR

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Burlington Resources Inc. s security holders during the fourth quarter of 2005.

EXECUTIVE OFFICERS OF THE REGISTRANT

Bobby S. Shackouls, 55 Chairman of the Board, President and Chief Executive Officer, Burlington Resources Inc., July 1997 to present.

Randy L. Limbacher, 47 Office of the Chairman, Burlington Resources Inc., January 2004 to present. Executive Vice President and Chief Operating Officer, Burlington Resources Inc., December 2002 to present. Senior Vice President, Production, Burlington Resources Inc., April 2001 to December 2002. President and Chief Executive Officer, BROG GP Inc., general partner of Burlington Resources Oil & Gas Company LP, December 2000 to July 2001.

Steven J. Shapiro, 53 Office of the Chairman, Burlington Resources Inc., January 2004 to present. Executive Vice President, Finance and Corporate Development, Burlington Resources Inc., April 2005 to present. Executive Vice President and Chief Financial Officer, Burlington Resources Inc., December 2002 to April 2005. Senior Vice President and Chief Financial Officer, Burlington Resources Inc., October 2000 to December 2002.

Mark E. Ellis, 49 Senior Vice President, North American Production, Burlington Resources Inc., September 2004 to present. President, Burlington Resources Canada Ltd., October 2000 to September 2004.

L. David Hanower, 46 Senior Vice President, Law and Administration, Burlington Resources Inc., July 1998 to present.

Joseph P. McCoy, 54 Senior Vice President and Chief Financial Officer, Burlington Resources Inc., April 2005 to present. Vice President and Controller, Burlington Resources Inc., May 2001 to April 2005. Vice President and Controller, Vastar Resources, Inc., May 1994 to March 2001.

John A. Williams, 61 Senior Vice President, Exploration, Burlington Resources Inc., April 2001 to present. Senior Vice President, Exploration, BROG GP Inc., general partner of Burlington Resources Oil & Gas Company LP, December 2000 to present.

PART II

ITEM FIVE

MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company s common stock, par value $.01 per share (Common Stock), is traded on the New York Stock Exchange under the symbol BR. Effective at the close of business on January 31, 2005, the Company discontinued the listing of its Common Stock on the Toronto Stock Exchange. At December 31, 2005, the number of record holders of Common Stock was 10,522. Information on Common Stock prices and quarterly dividends is shown on page 79 under the subheading Quarterly Financial Data Unaudited. See also Equity Compensation Plan Information under Part III, Item 12 of this report.

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)			
October 1, 2005 October 31, 2005	1,143	$71.03	1,143	$984,533
November 1, 2005 November 30, 2005	1,584	70.47	1,584	872,904
December 1, 2005 December 31, 2005	220	74.26	220	$856,596
Total	2,947	$70.97	2,947	

(1) In December 2000, the Company announced that the 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 the 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. Through October 25, 2005, the Company had the authority to purchase $193 million of its Common Stock under the program authorized in December 2004. On October 26, 2005, the Company announced that the Board voted to restore the authorization level to $1 billion. Through December 31, 2005, the Company had the authority to purchase $857 million of its Common Stock under the current authorization.

ITEM SIX

SELECTED FINANCIAL DATA

The selected financial data for the Company set forth below should be read in conjunction with the consolidated financial statements and accompanying notes thereto.

Year Ended December 31,	2005	2004	2003	2002	2001
	(In Millions, Except per Share Amounts)				
INCOME STATEMENT DATA					
Revenues	$ 7,587	$ 5,618	$ 4,311	$ 2,968	$ 3,419
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	4,048	2,304	1,570	569	907
Cumulative Effect of Change in Accounting Principle Net(2)			(59)		3
Net Income(1)	2,710	1,527	1,201	454	561
Basic Earnings per Common Share(1)(2)	7.13	3.90	3.02	1.13	1.35
Diluted Earnings per Common Share(1)(2)	7.07	3.86	3.00	1.13	1.35
Cash Dividends Declared per Common Share	$ 0.37	$ 0.32	$ 0.29	$ 0.28	$ 0.28
December 31,					
BALANCE SHEET DATA					
Total Assets	$19,225	$15,744	$12,995	$10,645	$10,582
Long-term Debt	3,893	3,887	3,873	3,853	4,337
Stockholders Equity	$ 8,935	$ 7,011	$ 5,521	$ 3,832	$ 3,525
Common Shares Outstanding	375	388	395	403	402

(1) Year 2005 includes an after tax gain of $149 million ($240 million pretax) or $0.39 per share related to the sale of 16,950,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company. Year 2005 also includes a non-cash after tax charge of $34 million ($50 million pretax) or $0.09 per share primarily related to the impairment of properties in onshore China.

Year 2005 and 2004 include income tax benefits of $51 million or $0.13 per share and $23 million or $0.06 per share, respectively, related to the reduction of the Canadian federal statutory income tax rate. Year 2004 also includes an income tax benefit of $45 million or $0.11 per share related to the reduction of the Alberta provincial income tax rate. In 2004, the Company recorded a U.S. income tax expense of $26 million or $0.07 per share related to the planned repatriation in 2005 of $500 million of eligible foreign earnings to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004. Year 2004 also includes a non-cash after tax charge of $59 million ($90 million pretax) or $0.15 per share related to the impairment of undeveloped properties in Canada.

Year 2003 includes an income tax benefit of $203 million or $0.51 per share related to the reduction of the Canadian federal income tax rate and $11 million or $0.02 per share related to the reduction of the Alberta provincial income tax rate. Year 2003 also includes a non-cash after tax charge of $38 million ($63 million pretax) or $0.09 per share related to the impairment of oil and gas properties in Canada.

(2) Year 2003 includes a cumulative effect of change in accounting principle (Cumulative Effect) after tax loss of $59 million ($95 million pretax) or $0.15 per share related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, *Asset Retirement Obligations.* Year 2001 includes a Cumulative Effect after tax gain of $3 million ($4 million pretax) or $0.01 per share related to the adoption of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended.

ITEMS SEVEN AND SEVEN A

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview

The Company is one of the largest independent exploration and production companies in North America. The Company explores for, develops and produces natural gas, NGLs and crude oil, from its properties primarily located in the onshore U.S. and western Canada, complemented by international operations. The Company s North American activities are concentrated in areas with known hydrocarbon resources, which are conducive to large, multi-well, repeatable drilling programs and the Company s technical skills. Internationally, the Company is focused on achieving operational efficiencies, while advancing potential growth opportunities in existing positions.

Basin Excellence^{SM} is the Company s concept of concentrating its operations and expertise in core areas where it believes it holds significant competitive advantages. These areas are typically in high potential geologic basins with large natural gas and crude oil resources that support multiple-year development programs. These are also areas where the Company holds significant land or mineral interest positions, has teams with years of relevant geologic, geophysical, engineering and operational experience, has access to production, processing and gathering infrastructure and has long-term relationships with partners, suppliers and land and mineral interest owners. The Company believes that it has attained or will ultimately attain this stature in several areas throughout the world that currently represent the majority of its core assets. These assets traditionally yield high returns on investment, and, therefore, the Company has concentrated its activities in these areas and exited other areas that did not meet these standards.

The Company has adopted a disciplined capital allocation process, with the objective of achieving annual volumetric growth (in the range of three to eight percent as a long-term annual average) coupled with strong financial returns.

In managing its business, the Company must deal with numerous risks and uncertainties. These risks and uncertainties can be broadly categorized as: subsurface, which includes the presence, size and recoverability of hydrocarbons; regulatory, which includes access and permitting necessary to conduct its operations; operational, which includes logistical, timing and infrastructure issues, especially internationally, which are often beyond the Company s control; and commercial, which includes commodity price volatility, local price differentials in various areas of its operations, and attention to operating margins and the availability of markets for its production, especially natural gas. Each of these factors is challenging and highly variable.

To address subsurface risks, the Company utilizes many of the latest technological tools available to assess and mitigate these risks. These tools include, but are not limited to, modern geophysical data and interpretation software, petrophysical information, physical core data, production histories, paleontology data and satellite imagery. In spite of these technologies, the multitude of unknown variables that exist below the surface of the earth make it difficult to consistently and accurately predict drilling results. In recent years, the Company has put considerable emphasis on creating an asset portfolio that improves the reliability of those predictions; however, these types of operations tend to exploit or develop smaller quantities of hydrocarbon reserves and, as a result, the Company must develop more of these opportunities in order to sustain its production growth goals. Similarly, the Company has reduced its focus on areas where there is far less analytical data available and drilling outcomes are less predictable, such as wildcat exploration operations in sparsely explored areas. The Company is constantly assessing its drilling opportunities to achieve balance in its drilling program for risk and financial returns. In order to make this possible, the Company attempts to maintain a large inventory of drillable projects from which its technical and management teams can select a drilling program in any given period.

On regulatory and operational matters, the Company actively manages its exploration and production activities. The Company values sound stewardship and strong relationships with all stakeholders in conducting its business. The Company attempts to stay abreast of emerging issues to effectively anticipate

and manage potential impacts on the Company s operations.
Managing the commercial risks is an ongoing priority at the Company. Considerable analysis of historical price trends, supply statistics, demand projections and infrastructure constraints form the basis of the Company s outlook for the commodity prices it may receive for its future production. Because much of this data is dynamic, the Company s view and the market s view of future commodity pricing can change rapidly. Based on the Company s ongoing assessment of the underlying data and the markets, the Company will from time to time use various financial tools to hedge the price it will receive for a particular commodity in the future. Margin enhancement is another important element of the Company s business, including focus on operating costs, administrative expenses and marketing activities, such as securing transportation to alternative market hubs to protect against weak producing-area prices. The Company may also enter into transportation agreements that allow the Company to sell a portion of its production in alternative markets when local prices are weak.
All of the risks and uncertainties described above create opportunities in the exploration and production business to the extent they drive the relative valuations of three distinct asset classes in the business. The first asset class is the commodities themselves natural gas, NGLs and crude oil. The prices for this asset class are generally established by the purchasers of these commodities, but closely track the prices that are set through the public trading of futures contracts for those same commodities. The second asset class consists of the physical oil and gas properties that may contain proved, probable and possible reserves, as well as exploratory potential. The value of physical assets is usually established in a private market created by a willing seller and a willing

buyer of a given property or group of properties. The third asset class consists of the equities of the publicly traded exploration and production companies that are valued in the public market place daily. Because these three asset classes are not always valued consistently with one another, opportunities may exist from time to time to take advantage of these various valuation differences. These valuation differences are key to the Company s capital allocation philosophy.

There are three types of investment alternatives that constantly compete for available capital at the Company. These include drilling opportunities, acquisition opportunities and financial alternatives such as share repurchases, dividends and debt repayment. Depending on circumstances and the relative valuations of the asset classes described above, the Company allocates capital among its investment alternatives through an allocation approach that is rate-of-return based. Its goal is to ensure that capital is being invested in the highest return opportunities available at any given time.

Much of what has been described above is conducted and handled routinely. The ability of the Company s management and staff to take into account all relevant factors, which fluctuate constantly, will be a key determinant in the Company s future performance.

Outlook

On December 12, 2005, BR and ConocoPhillips entered into a definitive agreement under which ConocoPhillips will acquire BR. Under the terms of the agreement, BR shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each BR share they own. The transaction is subject to approval by BR shareholders of record on February 24, 2006 and other customary terms and conditions. A special meeting of shareholders to vote on the proposed merger is March 30, 2006. Regulatory approvals have been granted and, upon approval by shareholders, the transaction is expected to close by March 31, 2006.

The merger agreement (Agreement) provides that until the effective time of the merger, BR will conduct its business in the ordinary course in all material respects, in substantially the same manner as conducted prior to the date of the Agreement, subject to certain conditions and restrictions as set forth in the Agreement. In addition, BR has agreed not to, except with prior written consent of ConocoPhillips, incur or commit to any capital expenditures, other than in the ordinary course of business or as contemplated by the 2006 capital budget. BR has agreed to pay ConocoPhillips a $1 billion termination fee in cash if BR terminates the Agreement prior to the approval by BR s shareholders of the Agreement, if BR s board of directors has determined that it has received a superior proposal and BR has complied with its obligation with respect to non-solicitation of other acquisition proposals and conditions.

In the ordinary course of business, the Company s business model strives to achieve both production growth and sector-leading financial returns when compared to other independent oil and gas exploration and production companies. This model 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.

Key to achieving the Company s financial goals is its disciplined capital investment approach. The Company deploys the net operating cash flows it generates among its core capital programs, as well as for acquisitions and other financial uses, such as share repurchases and dividend payments. Although commodity prices are volatile, the Company generally does not favor increasing or decreasing its capital program in response to commodity prices. Instead, the Company seeks to exercise a disciplined approach in order to keep its cost structure as low as possible.

The Company expects to continue focusing on exploring for and producing North American natural gas as its primary business. The Company expects its North America business to represent approximately 88 percent of its total production in 2006. While the Company s management recognizes that the North American natural gas business has many characteristics of a mature, slow-growth business, it believes that finding or acquiring and producing North American natural gas will continue to be a profitable, high-return business for the Company due to certain unique advantages that position it to be successful. First, the Company has long-lived asset positions in gas resource-prone basins and focuses heavily on maintaining a competitive cost structure. Secondly, the Company executes a consistent capital program by employing a capital allocation approach that favors discipline and balance.

The Company s International business segment is less mature, but has undergone a significant growth phase after several years of developing major projects. The International segment is expected to represent approximately 12 percent of the Company s total production in 2006.

Reserve Replacement

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to the Company s long-term success. Given the inherent decline of hydrocarbon reserves resulting from the production of those reserves, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined below, as an indicator of the Company s ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. The reserve replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries, and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table on pages 76-77 in the Supplementary Financial Information section of this report. Accordingly, the Company does not use unproved reserve quantities or proved reserve additions attributable to investments accounted for using the equity method in calculating its reserve replacement ratio. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

It is also important for an exploration and production company to demonstrate a long-term trend of adding reserves at a reasonable cost. Given that the cost of adding reserves is ultimately included in depreciation, depletion and amortization (DD&A) expense, management believes that the ability to add reserves in its core asset areas at a lower cost than its competition should contribute to a sustainable competitive advantage. The Company, in fact, has a goal to achieve 10 to 15 percent lower replacement costs than its competition in North America. Management therefore uses a per unit reserve replacement costs metric, as defined below, as an indicator of the Company s ability to replenish annual production volumes and grow reserves on a cost-effective basis. Analysts and investors use the measure widely and often cite the measure on a single year basis. In 2005, the Company s reserve replacement costs were $1.68 per MCFE including acquisitions or $1.61 per MCFE excluding acquisitions. The increase in costs in 2005 compared to 2004 was primarily due to industry service cost inflation. The Company typically cites reserve replacement costs in the context of a multi-year trend, in recognition of its limitations as a single year measure, but also to demonstrate consistency and stability, which are essential to the Company s business model. For the three-year period ended December 31, 2005, the Company s average reserve replacement costs were $1.40 per MCFE including acquisitions and $1.39 per MCFE excluding acquisitions. As used herein, reserve replacement costs represent total oil and gas capital costs, including acquisitions, incurred in order to add reserves. Reserve replacement costs per unit are calculated by dividing total oil and gas capital costs, including acquisitions, by the sum of reserve revisions, extensions, discoveries and other additions and acquisitions. The costs used to calculate reserve replacement costs include the costs of development, exploration, and property acquisition activities as presented in the Supplemental Oil and Gas Disclosures table on page 73 of this report.

Set forth below are the Company s reserve replacement ratio and reserve replacement costs per unit, along with the Company s capital expenditures.

Reserve Replacement

Year Ended December 31,	**2005**	**2004**	**2003**
		($ per MCFE)	
Reserve replacement costs, including acquisitions	$ 1.68	$ 1.27	$ 1.19
Reserve replacement costs, excluding acquisitions	$ 1.61	$ 1.27	$ 1.23
		(% of Production)	
Reserve replacement ratio, including acquisitions	149%	125%	142%
Reserve replacement ratio, excluding acquisitions	136%	119%	118%

Capital Expenditures

Year Ended December 31,	**2005**	**2004**	**2003**
		(In Millions)	

Total capital expenditures	$2,687	$1,747	$1,788
Less: acquisitions	328	85	228
Capital expenditures, excluding acquisitions	**$2,359**	**$1,662**	**$1,560**

The Company s focus on Basin Excellence[SM] in established, long-lived core assets results in the majority of its reserve additions coming from development drilling, including extensions from both infill and step-out drilling. Resource assessment studies in targeted areas also result in the addition of proved undeveloped reserves at infill and immediately adjacent locations in existing producing fields. Reserves added include both proved developed and proved undeveloped components for all periods presented. Over the past two years, the ratio of proved undeveloped reserves to total proved reserves has been about 27 percent. Proved developed reserves will generally begin producing within the year they are added. Proved undeveloped reserves generally require a major future expenditure and it is anticipated that approximately 80 percent of these reserves will begin producing within five years from the date in which the reserves are recorded. Due to the Company s extensive inventory of potential capital projects, reserve additions are expected to continue in the future, particularly in the Company s core operating areas, although there are no assurances as to the timing and magnitude of these additions.

In 2006, the Company expects to spend approximately $3.1 billion of capital, plus approved acquisitions. This level of spending represents a 33 percent increase over 2005 capital. The Company currently believes that this level of spending is needed to achieve its objective of three to eight percent average annual production growth. Approximately 88 percent of the Company s 2006 capital program is allocated to its North American programs in Canada and the U.S. This capital level in North America represents an increase of approximately 26 percent from prior year.

Below is a discussion of the Company s production levels and expected production growth.

Production

Year Ended December 31,	**2005**	**2004**	**2003**
		(MMCFE per day)	
U.S.	1,501	1,381	1,265
Canada	985	994	1,062
International	377	442	240
Total production	**2,863**	**2,817**	**2,567**

The Company has a goal to achieve between three and eight percent average annual production growth. In 2005, production volumes were 2,863 MMCFE per day, representing a 2 percent increase over 2004. In 2006, the Company expects production volumes to average between 2,940 and 3,100 MMCFE per day. The Company expects production growth in the U.S. during 2006 to be driven by increased production from Bossier, Cedar Creek, and Barnett Shale drilling programs. Production from the Rivers Fields commenced in October 2004; however, in November 2004, problems were encountered related to the acid plant. Production is expected to resume during the first quarter of 2006. The Company expects production from its international operations to range from a decline of 8 percent to an increase of 7 percent compared to production levels in 2005. In 2006, the Company expects production in Canada to decline from 1 to 4 percent compared to production levels in 2005.

While these activities are subject to the risks and delays inherent to this business as discussed above, the Company believes that these sources of production growth in the U.S. are currently available and therefore continues to focus on identifying sources of production growth for the future.

Financial Returns

In addition to the Company s production growth goal, it is committed to generating sector-leading returns on capital employed when compared to other independent oil and gas exploration and production companies. While commodity prices play a significant role in the Company s financial returns, the Company focuses on controllable elements such as certain operating costs. In the first quarter of 2006, the Company expects its operating costs to increase 7 to 13 percent and administrative expense to decrease 17 to 33 percent compared to the full year of 2005 on a per unit-of-production basis. The Company expects its operating costs to increase primarily due to industry service cost pressures. The Company expects administrative expense, which includes expenses related to compensation plans that are correlated to the Company stock, to decrease in the first quarter of 2006 compared to the full year of 2005. The Company expects DD&A expense to increase 11 to 19 percent on a unit-of-production basis in the first quarter of 2006 compared to the full year of 2005, primarily as a result of higher rates related to Canadian and International properties and unfavorable exchange rate impacts. Other costs could also increase as a result of unfavorable exchange rate impacts. Although subject to the upward cost pressures generally experienced by the industry, the Company believes it can differentiate its performance from that of its peers as a result of several initiatives underway to maintain its diligence on costs, specifically in the areas of purchasing, continuous process improvement, and knowledge transfer. The Company will continue to focus on capital efficiency and cost control.

Below are estimated and actual costs and expenses for the first quarter of 2006 and the full year of 2005, respectively.

	First Quarter 2006	Full Year 2005
	($ per MCFE)	
Transportation expense	$ 0.46 to $0.50	$ 0.47
Operating costs	0.72 to 0.76	0.67
DD&A	1.40 to 1.50	1.26
Administrative	$ 0.16 to $0.20	$ 0.24
	(In Millions)	
Exploration costs	$ 60 to $ 80	$ 293
Interest expense	$ 68 to $ 72	$ 281

Transportation expense in 2006 compared to 2005 is expected to range from a decrease of 2 percent to an increase of 6 percent, on a unit-of-production basis. The expected increase in transportation expense primarily results from the anticipated increase in production volumes in the U.S. Exploration costs are primarily dependent upon the size of the Company s drilling program and the success it has in finding commercial hydrocarbons. The Company cannot accurately forecast its exploration success rate but it expects exploration costs to exceed the costs incurred in 2005 primarily due to higher anticipated exploration capital spending.

Income Tax Expense

The ratio of current income tax expense to total income tax expense is expected to increase from historical ratios in the Canadian, International and U.S. jurisdictions as a result of the reversal of book tax differences, initiation of production in foreign locations and the exhaustion of Alternative Minimum Tax credit carryforwards.

Commodity Prices

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 numerous factors, including but not limited to, 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 average daily natural gas production in 2005, the Company estimates that a $0.10 per MCF change in natural gas prices would impact annual natural gas revenues approximately $70 million. Also, based on average daily crude oil production in 2005, the Company estimates that a $1.00 per barrel change in crude oil prices would impact annual crude oil revenues approximately $34 million.

Potential Acquisitions

While it is difficult to predict future plans with respect to acquisitions, the Company actively seeks acquisition opportunities that build upon the Company s existing core asset basins and conform to its Basin Excellence^{SM} concept. Although the Company does not plan major acquisitions, they play a large role in this industry s consolidation and must be considered. Generally, acquisitions for the Company fall into one of two categories: bolt-on transactions and other acquisitions. Bolt-on transactions are usually relatively small and involve acquiring properties and assets in areas where the Company already controls a core position. Other acquisitions tend to be transactions that involve the Company acquiring a core position in an area where it either has no position or a relatively small position. In either case, the purpose of acquiring assets is to assist the Company in adding to its existing inventory of future growth opportunities. Depending on the commodity price environment at any given time, the property acquisition market can be extremely competitive. Because of its focus on sector-leading financial returns, the Company takes a disciplined approach to property acquisitions, making it difficult to predict the number and frequency of future transactions. In accordance with the terms of the Agreement between BR and ConocoPhillips, individual acquisitions by the Company in excess of $50 million are subject to approval by ConocoPhillips.

Financial Condition and Liquidity

The Company s total debt to total capital (total capital is defined as total debt and stockholders equity) ratio at December 31, 2005 and December 31, 2004 was 30 percent and 36 percent, respectively. The 17 percent improvement in this ratio was attributable to the Company s strong net income and the strength of the Canadian currency 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 2006 capital expenditures, excluding any potential major acquisition(s). At December 31, 2005, the Company had $3,528 million of cash and cash equivalents on hand, of which $1,948 million was located in Canada, $1,285 million in the U.S. and $295 million in International. On October 27, 2005, the Company repatriated $500 million of eligible foreign earnings 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 $1,500 million 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 2001, the Company s Board of Directors authorized the Company to redeem, exchange or repurchase up to an aggregate of $990 million principal amount of debt securities.

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, of up to 27,577,741 units of beneficial interest in the Royalty Trust (Units) held by the Company. During the second half of 2005, the Company sold

16,950,000 Units, generating proceeds, after underwriting fees, of approximately $252 million. Net proceeds generated from the sale of Units were used primarily for the acquisitions of oil and gas properties. At December 31, 2005, $64 million of the net proceeds generated from the sale of Units were on deposit with a third-party intermediary to be used to purchase oil and gas properties during 2006.

The Company has a $1.5 billion revolving credit facility (Credit Facility) that includes (i) a US$500 million Canadian subfacility 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 December 31, 2005, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

The Company s access to funds from its Credit Facility is not restricted under any material adverse condition clauses. These clauses typically remove the obligation of the lenders to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower s financial condition, operations or properties considered as a whole, the borrower s ability to make timely debt payments, or the enforceability of material items of the credit agreement. While the Company s Credit Facility includes a covenant that requires the Company to report litigation or a proceeding that the Company has determined is likely to have a material adverse effect on the consolidated financial condition of the Company, the obligation of the lenders to fund the Credit Facility is not conditioned on the absence of such litigation or proceeding.

Net cash provided by operating activities in 2005 increased $1,100 million and $1,997 million over 2004 and 2003, respectively, primarily due to higher commodity prices and higher production volumes partially offset by higher costs and expenses, excluding non-cash expenses. Key drivers of net operating cash flows are commodity prices, production volumes and costs and expenses. Average natural gas prices increased 32 percent and 49 percent over 2004 and 2003, respectively. Crude oil prices increased 40 percent and 87 percent over 2004 and 2003, respectively, while NGLs prices increased 30 percent and 61 percent over the same period. Crude oil volumes increased 9 percent and 100 percent over 2004 and 2003, respectively. NGLs volumes increased 2 percent and 3 percent over 2004 and 2003, respectively. Natural gas volumes in 2005 were essentially the same as 2004 and 2003. Although the Company believes that 2006 production volumes will exceed 2005 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 in 2005 is not necessarily indicative of future cash flows from operating activities. See page 22 for a discussion of commodity prices.

The increase in net cash provided by operating activities resulting from higher commodity prices and higher production volumes was partially offset by higher costs and expenses. In 2005, costs and expenses that affect net operating cash provided by operating activities primarily include operating costs, taxes other than income taxes, transportation expenses, and administrative expenses. These costs and expenses increased $289 million and $570 million over 2004 and 2003, respectively. 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 24 percent and 30 percent of the increase in costs and expenses over 2004 and 2003, respectively. Taxes other than income taxes include severance taxes, which are directly correlated to crude oil and natural gas revenues. Severance taxes accounted for 25 percent and 24 percent of the increase in costs and expenses over 2004 and 2003, respectively. For revenue, price, volume and costs and expense variances, see tables and explanations on pages 29-34.

Generally, producing natural gas and crude oil reservoirs have declining production rates. Production rates are impacted by numerous factors, including but not limited to, geological, geophysical and engineering matters, production curtailments and restrictions, weather, market demands and the Company s ability to replace depleting reserves. The Company s inability to adequately replace reserves could result in a decline in production volumes, one of the key drivers of generating net operating cash flows. The Company s reserve replacement ratio for the year ended December 31, 2005 was 149 percent and has averaged 139 percent over the last three years. Results for any year are a function of the success of the Company s drilling program and acquisitions. While program results are difficult to predict, the Company s current drilling inventory provides the Company opportunities to replace its production in 2006.

The Company has various contractual obligations primarily related to leases for office space, other property and equipment and demand charges on firm transportation agreements for its production of natural gas and crude oil. The Company expects to fund these contractual obligations with cash generated from operations. The following table summarizes the Company s contractual obligations at December 31, 2005.

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(In Millions)		
Total debt(1)	$3,933	$ 502	$ 481	$1,228	$1,722
Interest payments on long-term debt	3,421	270	656	378	2,117
Transportation demand charges(2)	797	152	288	119	238
Non-cancellable operating leases(2)	307	36	100	71	100
Postretirement benefits(3)	29	3	9	6	11
Pension funding(3)	12	12			
Drilling rig commitments(2)	139	65	69	5	
Total Contractual Obligations	**$8,638**	**$1,040**	**$1,603**	**$1,807**	**$4,188**

(1) See Note 9 of Notes to Consolidated Financial Statements for details of long-term debt.
(2) See Note 14 of Notes to Consolidated Financial Statements for discussion of these commitments.
(3) See Note 13 of Notes to Consolidated Financial Statements for discussion of the Company s benefit plans.

The Company also has liabilities of $604 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2005. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. See Note 10 of Notes to Consolidated Financial Statements.

Certain of the Company s contracts require the posting of collateral upon request in the event that the Company s long-term debt is rated below investment grade or ceases to be rated. Those contracts primarily consist of hedging agreements and two long-term natural gas transportation agreements. A few of the hedging agreements also require posting of collateral if the market value of the transactions thereunder exceed a specified dollar threshold that varies with the Company s credit rating. As of December 31, 2005, the Company has a BBB+ long-term debt rating from Standard & Poors and A3 Moody s Investors Service (Moody s) rating. Investment grade is designated as all ratings above BB+ for Standard & Poors and Ba1 for Moody s.

While the mark-to-market positions under the hedging agreements will fluctuate with commodity prices, as a producer, the Company s liquidity exposure due to its outstanding derivative instruments tends to increase when commodity prices increase. Consequently, the Company is most likely to have its largest unfavorable mark-to-market position in a high commodity price environment when it is least likely that a credit support requirement due to an adverse rating action would occur. At December 31, 2005, the aggregate unfavorable mark-to-market position under the aforementioned hedging agreements was approximately $72 million. In the case of the Canadian transportation agreements, the collateral required would be an amount equal to 12 months of estimated demand charges. That amount totaled approximately $33 million as of December 31, 2005.

In the normal course of business, the Company has performance obligations which are supported by surety bonds or letters of credit. These obligations are primarily for site restoration and dismantlement, royalty payment appeals and excise tax exemption certifications where governmental organizations require such support.

Changes in credit rating also impact the cost of borrowing under the Company s Credit Facility, but have no impact on availability of credit under the agreements.

In December 2000, the Company announced that the 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 the 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. Through October 25, 2005, the Company had the authority to purchase $193 million of its Common Stock under the program authorized in December 2004. On October 26, 2005, the Company announced that the Board voted to restore the authorization level to $1 billion. Through December 31, 2005, the Company had the authority to purchase $857 million of its Common Stock under the current authorization.

During 2005, the Company repurchased approximately 16 million shares of its Common Stock for approximately $902 million and, as of December 31, 2005, had authority to repurchase an additional $857 million of its Common Stock under the current authorization. Share repurchases of $8 million related to 2004 transactions were cash settled during 2005. Since December 2000, the Company has repurchased approximately 77 million shares of its Common Stock for $2.5 billion.

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.

Off-Balance Sheet Arrangements

The Company has off-balance sheet arrangements that it believes have not and are not reasonably likely to have a material current or future effect on the Company s results of operations, financial condition, liquidity, capital expenditures or capital resources. These off-balance sheet arrangements consist of equity investments in two entities that the Company accounts for under the equity method. The book values of the Company s interests in Lost Creek Gathering Company, L.L.C. (Lost Creek) and Evangeline Gas Pipeline Company (Evangeline) are $23 million and $2 million, respectively. As of December 31, 2005, Lost Creek had outstanding debt totaling $37 million and Evangeline had outstanding debt totaling $28 million. Lost Creek and Evangeline s debts are non-recourse to the Company, and as a result, the Company has no legal responsibility or obligation for these debts. Management believes that Lost Creek and Evangeline are financially stable and therefore will be in a position to repay their outstanding debts.

Capital Expenditures and Resources

Capital expenditures were as follow.

				2005 vs. 2004		2005 vs. 2003	
Year Ended December 31,	**2005**	**2004**	**2003**	**Increase (Decrease)**	**% Increase (Decrease)**	**Increase (Decrease)**	**% Increase (Decrease)**
				($ in millions)			
Oil and gas							
Development	$1,819	$1,273	$1,056	$546	43%	$ 763	72%
Exploration	467	286	301	181	63	166	55
Acquisitions	328	85	228	243	286	100	44
Total oil and gas	**2,614**	**1,644**	**1,585**	**970**	**59**	**1,029**	**65**
Plants and pipelines	44	66	163	(22)	(33)	(119)	(73)
Administrative and other	29	37	40	(8)	(22)	(11)	(28)
Total capital expenditures	**$2,687**	**$1,747**	**$1,788**	**$940**	**54%**	**$ 899**	**50%**

The Company s consolidated capital expenditures were up 54 percent and 50 percent compared to 2004 and 2003, respectively. Excluding acquisitions, the Company s capital spending related to internal development and exploration was up 47 and 68 percent compared to 2004 and 2003, respectively. Capital expenditures in 2006, excluding proved property acquisitions, are expected to be approximately $3.1 billion, up 33 percent over 2005, primarily due to anticipated higher project counts in major operating areas, increased service costs, and higher foreign currency exchange rates, particularly in Canada. The Company believes that 2006 estimated spending is sufficient to add adequate reserves and achieve the target of three to eight percent average annual production growth. Capital expenditures in 2006 are expected to be primarily for internal development and exploration of oil and gas properties. Capital spending in 2006 related to internal development and exploration is expected to be about 29 percent higher than 2005 and is expected to be funded from internally generated cash flows.

Marketing

North America (U.S. and Canada)

The Company s marketing strategy is to maximize the value of its production by developing marketing flexibility from the wellhead to its ultimate sale. The Company s natural gas production is gathered, processed, exchanged and transported utilizing various firm and interruptible contracts and routes to access higher value market hubs. The Company s customers include local distribution companies, electric utilities, industrial users and marketers. The Company maintains the capacity to ensure its production can be marketed either at the wellhead or downstream at market sensitive prices.

All of the Company s crude oil production is sold to third parties at the wellhead or transported to market hubs where it is sold or exchanged. NGLs are typically sold at field plants or transported to market hubs and sold to third parties. Downgrades or the inability of the Company s customers to maintain their credit rating or credit worthiness could result in an increase in the allowance for unrecoverable receivables from natural gas, NGLs or crude oil revenues or it could result in a change in the Company s assumption process of evaluating collectibility based on situations regarding specific customers and applicable economic conditions.

International

The Company s International production is marketed to third parties either directly by the Company or by the operators of the properties. Production is sold at the platforms or various sales points based on spot or contract prices.

Qualitative and Quantitative Disclosure About Market Risk

Commodity Risk

Substantially all of the Company s natural gas, NGLs and crude oil production is sold on the spot market or under short-term contracts at market sensitive prices. Spot market prices for domestic natural gas and crude oil 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 basis differentials. 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. In order to accommodate the needs of its customers, 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 December 31, 2005, the potential decrease in fair value of derivative instruments assuming a 10 percent adverse movement (an increase in the underlying commodities prices) would result in a $77 million decrease in the net unrealized gain. The derivative instruments in place at December 31, 2005 hedged approximately 10 percent and 11 percent of the Company s expected natural gas and crude oil production volumes, respectively, through 2006.

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. As more fully described in Note 1 of Notes to Consolidated Financial Statements, the Company periodically assesses the effectiveness of its derivative instruments in achieving offsetting cash flows attributable to the risks being hedged. Changes in basis differentials or notional amounts of the hedged transactions could cause the derivative instruments to fail the effectiveness test and result in mark-to-market accounting for the affected derivative transactions which would be reflected in the Company s current period earnings.

Credit and Market Risks

The Company manages and controls market and counterparty credit risk through a system of established internal controls and procedures which are reviewed on a periodic basis. The Company attempts to minimize credit risk exposure to counterparties through formal credit policies and monitoring procedures as well as the use of netting arrangements and requiring letters of credit or parent guarantees, when necessary. Accounts receivable are stated at historical value which approximates fair market value on the Company s Consolidated Balance Sheet and no single customer of the Company constitutes more than six percent of the Company s accounts receivable balance at December 31, 2005. In the normal course of business, collateral is not required for financial instruments with credit risk. The fair value of the Company s fixed-rate debt is subject to change based on changes in interest rates. From time to time, the Company enters into financial derivatives to manage this exposure. Based on financial derivative transactions in place as of year-end 2005, a 10 percent adverse move in interest rates (an increase in the underlying interest rates) would result in less than a $1 million increase in interest expense. Additionally, the Company has cash investments that it manages based on internal investment guidelines that emphasize liquidity and preservation of capital, and such cash investments are stated at historical cost which approximates fair market value on the Company s Consolidated Balance Sheet.

Foreign Currency Risk

The Company has exposure to currency risk in certain of its foreign subsidiaries where the functional currency is the U.S. dollar and where some of the transactions are denominated in the local currency. The Company monitors and manages its exposure to foreign currency risk in these subsidiaries primarily by balancing local currency monetary assets and liabilities. The Company does not actively manage foreign currency risk in its other foreign subsidiaries where the U.S. dollar is not the functional currency, primarily Canada, since the majority of transactions are denominated in the local currency. A substantial amount of the Company s cash is located in Canada, in Canadian dollars, which provides a natural hedge against foreign currency risk. As of December 31, 2005, the Company had no foreign currency financial derivatives.

Dividends

On January 25, 2006, the Board declared a Common Stock quarterly cash dividend of $0.10 per share, payable April 10, 2006 to shareholders of record on March 9, 2006. During the third quarter of 2005, the Company increased its quarterly cash dividend from $0.085 to $0.10 per share, representing an 18 percent increase. Dividend levels are determined by the Board based on profitability, capital expenditures, financing and other factors. The Company declared and paid cash dividends on Common Stock totaling approximately $141 million and $136 million, respectively, during 2005.

Application of Critical Accounting Policies

Oil and Gas Reserves

The Company s estimate of proved reserves reflects quantities of natural gas, NGLs and crude oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic conditions. The process of estimating quantities of natural gas, NGLs and crude oil reserves requires judgment in the evaluation of all available geological, geophysical, engineering and economic data, including production data, reservoir pressure data, and data collected as a result of development or exploration drilling. Economic and operating conditions, such as product prices, the availability of additional development capital, operating costs, development costs, production tax rates, the installation of additional infrastructure, regulatory approval and actions of domestic or foreign governments influence the estimation of reserves. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Company s reserves.

The Company has policies and procedures through which the required engineering, geological, and economic data is gathered and proved reserves are estimated. Experienced and qualified Company engineers prepare the reserve estimates. These estimates are subjected to a series of internal reviews to ensure that they are technically and legally justified and therefore reasonable, prepared using generally accepted principles and practices, and comply with SEC regulations. A corporate staff of engineers conducts oversight and audit of the reserve estimates. Furthermore, the reserve maintenance process requires review and approval of every change to the proved reserve ledger, the most significant requiring approval by the Company s Chief Engineer.

The Company also engages independent oil and gas engineering consulting firms to review its proved reserves base. The firms determine both the specific properties reviewed and the aggregate magnitude they require for review. Typically, at least 80 percent of the estimated proved reserves receive external review. The Company s reserve estimates during 2005, 2004, and 2003 were subjected to this external review by the independent oil and gas consultants, who in their judgment determined the estimates to be reasonable in the aggregate. At the conclusion of their external review, the audit firms issue a written opinion and present their findings to the members of the Board of Directors Audit Committee. For more information, see the independent oil and gas consultant s letters on pages 68-72.

Despite the inherent imprecision in these engineering estimates, the Company s reserves are used throughout its financial statements. As described in Note 1 of Notes to Consolidated Financial Statements, the Company uses the unit-of-production method to amortize the costs of its oil and gas properties. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision or, in some cases, an impairment charge in the period of the revision. Although revisions to reserve estimates in previous years have averaged less than one percent, a five percent negative or adverse revision to the Company s consolidated proved reserves would result in an increase in annual DD&A expense of approximately $62 million. See the Supplementary Financial Information in this report for reserve data.

Successful Efforts Method of Accounting

The Company accounts for its oil and gas properties using the successful efforts method of accounting. Acquisition and development costs are capitalized and amortized using the unit-of-production method based on total proved and proved developed reserves, respectively, estimated by the Company s reserve engineers. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision. Unsuccessful exploration or dry hole wells are expensed as exploration cost in the period in which the wells are determined to be dry and could have a significant effect on results of operations.

Carrying Value of Long-lived Assets

As more fully described in Note 1 of Notes to Consolidated Financial Statements, the Company performs an impairment analysis on its proved properties whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable and annually for the Company s unproved reserves. Cash flows used in the impairment analysis are determined based upon management s estimates of proved natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves. Downward revisions in estimated reserve quantities, increases in future cost estimates or depressed natural gas, NGLs and crude oil prices could cause the Company to reduce the carrying amounts of its properties. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Because natural gas, NGLs and crude oil prices are volatile, these estimates are inherently imprecise. A five percent negative or adverse revision to the Company s proved reserves combined with a 10 percent decline in the natural gas price used to identify fields that are potentially impaired would not have resulted in an additional impairment charge for the year ended December 31, 2005. See Note 16 of Notes to Consolidated Financial Statements for a discussion of impairment of oil and gas properties.

The Company s lease acquisition costs are not subject to the impairment analysis described above, however, a portion of the costs associated with such properties is subject to amortization on a composite basis based on past experience and average property lives. On an annual basis, the Company monitors the estimated success rate used to determine the amount of lease acquisition costs that are not subject to amortization and makes an adjustment, if needed. Typically, these adjustments do not have a significant impact on future amortization. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity are expensed in the period the determination is made. The rate at which the unproved properties are written off depends on the timing and success of the Company s future exploration program.

Asset Retirement Obligations (ARO)

The Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment and additionally to dismantle and abandon plants at the end of oil and gas production operations. The Company records the fair value of a liability for ARO in the period in which it is incurred and a corresponding increase in the carrying amount of the related asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using a systematic and rational method. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as additional DD&A expense in the Consolidated Statement of Income.

Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. The Company uses the present value of estimated cash flows related to its ARO to determine the fair value. The present value calculation includes numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. Abandonment cost estimates are determined by the Company s reserve engineers based on actual costs incurred to abandon similar wells, and their knowledge of the respective wells. The Company has been unable to determine the accuracy of these estimates due to the limited amount of abandonment activity since the adoption of SFAS No. 143. The Company uses an inflation factor determined by analyzing an industry specific price index that it updates annually. Timing of settlement is based on reserve estimates and is subject to the same inherent imprecision described above for oil and gas reserves. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the related asset. A five percent increase in the Company consolidated ARO would result in a $30 million increase in the Company s obligation and a $2 million increase in annual accretion expense.

Goodwill

As required, the Company performs an annual impairment assessment in lieu of periodic amortization of goodwill. The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. The Company determined the fair value of its Canadian reporting unit using a combination of the income approach and the market approach. Under the income approach, the Company estimated the fair value of the reporting unit based on the present value of expected future cash flows. Under the market approach, the Company estimated the fair value based on market multiples of reserves and production for comparable companies.

The income approach is dependent on a number of factors including estimates of forecasted revenue and costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar or depressed natural gas, NGLs and crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. Under the market approach, the Company makes certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although the Company based its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. In 2005, the Company used a professional valuation services firm to assist in preparing its annual valuation of the Canadian reporting unit. At December 31, 2005, the fair value of the Canadian reporting unit exceeded its carrying amount and the use of other reasonable assumptions would not have changed the outcome of the impairment test.

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales prices for natural gas, NGLs and crude oil are adjusted for transportation costs and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third-party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer.

Legal, Environmental and Other Contingencies

A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the subjective judgment of management. In many cases, management s judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies in dealing with similar matters, and the decision of management on how it intends to respond to a particular contingency (for example, a decision to contest a matter vigorously or a decision to seek a negotiated settlement). The Company s management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company.

Results of Operations

Year Ended December 31, 2005 Compared With Year Ended December 31, 2004

The Company s consolidated net income increased to $2,710 million or $7.07 diluted earnings per common share (per share) in 2005 primarily due to higher commodity prices and higher production volumes. Net income in 2005 includes a gain of $240 million or $0.39 per share related to the sale of 16,950,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company. Net income in 2005 and 2004 included charges, net of taxes, of $34 million or $0.09 per share and $59 million or $0.15 per share, respectively, related to the impairment of oil and gas properties. Net income in 2005 and 2004 included income tax benefits of $51 million or $0.13 per share and $23 million or $0.06 per share, respectively, related to the reduction of the Canadian federal income tax rate. Net income in 2004 also included income tax benefits of $45 million or $0.11 per share related to the reduction of the Alberta provincial corporate income tax rate. In 2004, the Company recorded a U.S. income tax expense of $26 million or $0.07 per share related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. in 2005 under the one-time provisions of the American Jobs Creation Act of 2004.

Below is a discussion of prices, volumes and revenue variances.

Price and Volume Variances

				2005 vs. 2004		
Year Ended December 31,	**2005**	**2004**	**2003**	**Increase (Decrease)**	**% Increase**	**Increase (Decrease)**
						(In Millions)
Price Variance						
Natural gas sales prices (per MCF)	$ 7.22	$ 5.49	$ 4.83	$ 1.73	32%	$1,200
NGLs sales prices (per Bbl)	32.88	25.38	20.40	7.50	30	184
Crude oil sales prices (per Bbl)	$50.77	$36.25	$27.22	$14.52	40%	493
Total price variance						**$1,877**
Volume Variance						
Natural gas sales volumes (MMCF per day)	1,905	1,914	1,899	(9)	%	$ (29)

NGLs sales volumes (MBbls per day)	66.7	65.3	64.8	1.4	2	11
Crude oil sales volumes (MBbls per day)	93.0	85.2	46.5	7.8	9%	100
Total volume variance						**$ 82**

Revenue Variances

Year Ended December 31,	2005	2004	2003	2005 vs. 2004 Increase	2005 vs. 2004 % Increase
		($ In Millions)			
Natural gas	$5,018	$3,847	$3,331	$1,171	30%
NGLs	801	606	482	195	32
Crude oil	1,724	1,131	462	593	52
Processing and other	44	34	36	10	29
Total revenues	**$7,587**	**$5,618**	**$4,311**	**$1,969**	**35%**

Revenues

The Company s consolidated revenues increased $1,969 million in 2005 compared to 2004. Higher revenues were primarily due to higher commodity prices and higher crude oil and NGLs production volumes, resulting in increased revenues of $1,877 million and $111 million, respectively. Increased revenues related to higher commodity prices and higher oil and NGLs sales volumes were partially offset by lower natural gas sales volumes, resulting in reduced revenues of $29 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 generation and net operating cash flow for the Company. Higher commodity prices contributed $1,877 million to the increase in revenues in 2005. Average natural gas prices, including a $0.23 realized loss per MCF related to hedging activities, increased $1.73 per MCF during 2005, resulting in increased revenues of $1,200 million. Average crude oil prices, including an $0.80 realized loss per barrel related to hedging activities, increased $14.52 per barrel in 2005, resulting in increased revenues of $493 million. Average NGLs prices increased $7.50 per barrel in 2005, resulting in higher revenues of $184 million. As discussed on page 12, commodity prices are affected by many factors that are outside of the Company s control. Therefore, commodity prices received by the Company during 2005 are not necessarily indicative of prices it may receive in the future. Depressed commodity prices over a significant period of time would result in reduced cash from operating activities potentially causing the Company to expend less on its capital program. Lower spending on the capital program could result in a reduction of the amount of production volumes the Company is able to produce. The Company cannot accurately predict future commodity prices, and cannot be certain whether these events will occur.

Volume Variances

Sales volumes are another key driver that impact the Company s earnings and net operating cash flow. Higher sales volumes in 2005 resulted in increased revenues of $82 million. Average crude oil sales volumes increased 7.8 MBbls per day in 2005, resulting in increased revenues of $100 million. The increase in crude oil sales volumes in 2005 was primarily due to higher production from the Cedar Creek Anticline which increased 9.4 MBbls per day and the Bakken Shale which increased 4.2 MBbls per day partially offset by decreased production of 3.9 MBbls per day in China.

Average NGLs sales volumes increased 1.4 MBbls per day in 2005, resulting in higher revenues of $11 million. Average NGLs sales volumes increased primarily due to higher production of 0.6 MBbls per day from Canada and 0.5 MBbls per day from the Waddell Ranch Field.

Average natural gas sales volumes decreased 9 MMCF per day in 2005, resulting in decreased revenues of $29 million. Average natural gas sales volumes decreased primarily due to lower production of 35 MMCF per day from the San Juan Basin, 19 MMCF per day from Millom and Dalton in the East Irish Sea, 15 MMCF per day from Canada and 12 MMCF per day from south Louisiana. These decreases were partially offset by higher production volumes in the Bossier trend of 69 MMCF per day.

The Company has a goal to achieve between three and eight percent average annual production growth; therefore, future production volumes are expected to increase over the current period. See discussion under Outlook on page 19 for guidance on production volumes. As mentioned above, depressed prices over an extended period of time or other unforeseen events could occur that would result in the Company being unable to sustain a capital program that allows it to meet its production growth goals. However, the Company cannot predict whether such events will occur.

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

Total Costs and Other Income Net

Year Ended December 31,	**2005**	**2004**	**2003**	**2005 vs. 2004 Increase (Decrease)**	**2005 vs. 2004 % Increase (Decrease)**
	($ In Millions)				
Costs and other income net					
Taxes other than income taxes	$ 355	$ 260	$ 187	$ 95	37%
Transportation expense	496	453	408	43	9
Operating costs	697	587	475	110	19
Depreciation, depletion and amortization	1,313	1,137	927	176	15
Exploration costs	293	258	252	35	14
Impairment of oil and gas properties	50	90	63	(40)	(44)
Administrative	256	215	164	41	19
Interest expense	281	282	260	(1)	
(Gain)/loss on disposal of assets	(240)	13	(8)	253	N/A
Other expense net	38	19	13	19	100
Total costs and other income net	**$3,539**	**$3,314**	**$2,741**	**$225**	**7%**

Total costs and other income net increased $225 million in 2005. This increase in total costs and other income net was primarily due to the items discussed below. The increase in the exchange rate in Canada during 2005 impacted certain costs and expenses for the Company. Changes in the value of the Canadian dollar versus the U.S. dollar could impact costs and expenses in future years. However, the Company cannot predict what impact the Canadian exchange rate will have on costs and expenses in the future. See discussion under Outlook on page 21 for guidance on costs and expenses for the first quarter of 2006.

DD&A expense increased $176 million primarily due to asset additions with higher unit-of-production rates, and higher foreign currency exchange rates. Operating costs increased $110 million in 2005 compared to 2004. This increase is primarily due to higher divisional office expenses related to various compensation programs and higher well operating expenses, which include direct expenses incurred to operate the Company s wells and equipment on producing leases. Well operating expenses were higher primarily due to increased fuel and electricity expenses, higher repair and maintenance expenses, higher workover activity and higher foreign currency exchange rates.

Taxes other than income taxes increased $95 million primarily due to higher production taxes resulting from higher crude oil and natural gas revenues. Production taxes include severance taxes which are directly correlated to natural gas and crude oil revenues. Transportation expense increased $43 million primarily due to the U.S. and International operations. Administrative expense increased $41 million primarily due to various compensation programs primarily related to the increase in the Company s stock price as well as other performance measures, and merger costs related to the proposed merger between BR and ConocoPhillips.

The Company performs an impairment analysis annually for unproved reserves or whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon management s estimates of natural gas, NGLs and crude oil reserves, future natural gas, NGLs and crude oil prices, and costs to extract these reserves. In 2005 and 2004, the Company recorded non-cash charges of $50 million and $90 million, respectively, related to the impairment of oil and gas properties. The impairment of oil and gas properties in 2005 was related to a downward reserve adjustment primarily related to the Company s onshore China properties. The impairment in 2004 was related to undeveloped properties in Canada.

Exploration costs increased $35 million due to higher geological and geophysical (G&G) and other expenses of $25 million, higher amortization of undeveloped lease costs of $10 million and higher exploratory dry hole costs of $8 million partially offset by lower deepwater rig impairment of $8 million. Exploration expense fluctuates 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. Of the exploratory wells drilled by the Company in 2005, 2004 and 2003, the Company experienced a success rate in the range of approximately 50 to 71 percent during that period of time. These success rates are not necessarily indicative of future rates. The Company capitalizes costs incurred to drill exploratory wells pending determination of whether the wells have found an adequate amount of economically recoverable reserves to be classified as proved. When a determination cannot be made at the time drilling is completed, the costs are deferred until a determination can be made. At December 31, 2005, $25 million of deferred exploration drilling costs were included in oil and gas properties on the Company s Consolidated Balance Sheet. Some or all of these costs could be included in exploration expense in future periods. In 2005 and 2004, deferred exploration drilling costs of $16 million and $14 million, respectively, were reclassified from oil and gas properties to exploration expense.

In 2005, gain on disposal of assets increased $253 million primarily due to a $240 million pretax gain related to the sale of 16,950,000 units of beneficial interest in the Permian Basin Royalty Trust held by the Company. Other expense net increased $19 million primarily due to higher legal cost accruals of $42 million and higher foreign currency transaction losses of $36 million, partially offset by higher interest income of $41 million resulting from higher cash balances, lower write-offs of inventory of $7 million and lower interest expense related to tax and other matters of $6 million.

Income Tax Expense

Income tax expense increased $561 million in 2005 compared to 2004, primarily due to an increase in pretax income of $1,744 million. During 2005, the Company recorded higher income tax benefits of $52 million related to return as filed adjustments and higher income tax benefits of $8 million related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing. The increase in the tax benefit related to cross-border financing is the result of changes in the exchange rate. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly-owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada. This benefit is not expected to fluctuate in the future for reasons other than changes in exchange rate and debt levels. The Company recorded a higher income tax expense of $35 million related to taxes on foreign income in excess of U.S. rates. In 2005, the Company also recorded lower income tax benefits of $17 million related to the Canadian federal statutory income tax rate reductions. In 2004, the Company recorded $26 million of U.S. income tax expense related to its planned repatriation in 2005 of $500 million of eligible foreign earnings under the one-time provisions of the American Job Creation Act of 2004.

Year Ended December 31, 2004 Compared With Year Ended December 31, 2003

The Company s consolidated net income increased $326 million or $0.86 diluted earnings per common share in 2004 primarily due to higher commodity prices and higher production volumes. Net income in 2004 and 2003 included charges, net of taxes, of $59 million or $0.15 per share and $38 million or $0.09 per share, respectively, related to the impairment of oil and gas properties primarily in Canada. Net income in 2004 and 2003 included income tax benefits of $23 million or $0.06 per share and $203 million or $0.51 per share, respectively, related to the reduction of the Canadian federal statutory income tax rate. Net income in 2004 and 2003 also included income tax benefits of $45 million or $0.11 per share and $11 million or $0.02 per share, respectively, related to the reduction of the Alberta provincial corporate income tax rate. In 2004, the Company recorded a U.S. income tax expense of $26 million or $0.07 per share related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. under the one-time provisions of the American Jobs Creation Act of 2004. Net income in 2003 also included a net-of-tax cumulative effect of change in accounting principle charge of $59 million or $0.15 per share related to the adoption of SFAS No. 143, *Asset Retirement Obligations.* See Note 10 of Notes to Consolidated Financial Statements for more information.

Below is a discussion of prices, volumes and revenue variances.

Price and Volume Variances

				2004 vs. 2003		
Year Ended December 31,	**2004**	**2003**	**2002**	**Increase**	**% Increase**	**Increase**
						(In Millions)
Price Variance						
Natural gas sales prices (per MCF)	$ 5.49	$ 4.83	$ 3.20	$0.66	14%	$462

NGLs sales prices (per Bbl)	25.38	20.40	14.46	4.98	24	119
Crude oil sales prices (per Bbl)	$36.25	$27.22	$24.11	$9.03	33%	282
Total price variance						**$863**
Volume Variance						
Natural gas sales volumes (MMCF per day)	1,914	1,899	1,916	15	1%	$ 35
NGLs sales volumes (MBbls per day)	65.3	64.8	60.1	0.5	1	5
Crude oil sales volumes (MBbls per day)	85.2	46.5	49.1	38.7	83%	387
Total volume variance						**$427**

Revenue Variances

Year Ended December 31,	2004	2003	2002	2004 vs. 2003 Increase (Decrease)	2004 vs. 2003 % Increase (Decrease)
		($ In Millions)			
Natural gas	$3,847	$3,331	$2,209	$ 516	15%
NGLs	606	482	317	124	26
Crude oil	1,131	462	432	669	145
Processing and other	34	36	10	(2)	(6)
Total revenues	**$5,618**	**$4,311**	**$2,968**	**$1,307**	**30%**

Revenues

The Company s consolidated revenues increased $1,307 million in 2004. Higher revenues were primarily due to higher commodity prices and higher production volumes, resulting in increased revenues of $863 million and $427 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 generation and net operating cash flow for the Company. Higher commodity prices contributed $863 million to the increase in revenues in 2004. Average natural gas prices, including a $0.01 realized loss per MCF related to hedging activities, increased $0.66 per MCF during 2004, resulting in increased revenues of $462 million. Average crude oil prices, including a $0.99 realized loss per barrel related to hedging activities, increased $9.03 per barrel in 2004, resulting in increased revenues of $282 million. Average NGLs prices increased $4.98 per barrel in 2004, resulting in higher revenues of $119 million. See page 22 for a discussion of commodity prices.

Volume Variances

Sales volumes are another key driver that impact the Company s earnings and net operating cash flow. Higher sales volumes in 2004 resulted in increased revenues of $427 million. Average crude oil sales volumes increased 38.7 MBbls per day in 2004, resulting in increased revenues of $387 million. The increase in crude oil sales volumes was primarily due to higher production from International s new project start-ups in late 2003 from fields in offshore China, Algeria and Ecuador, which contributed increased production of 17.9 MBbls per day, 8.6 MBbls per day and 3.9 MBbls per day, respectively, in 2004. Production from the U.S. Cedar Creek Anticline increased 6.6 MBbls per day and the Bakken Shale increased 1.5 MBbls per day in 2004.

Average natural gas sales volumes increased 15 MMCF per day in 2004, resulting in increased revenues of $35 million. Average natural gas sales volumes increased primarily due to higher production from the Madden Field, CLAM in the Dutch sector of the North Sea, and south Louisiana, which contributed increased production of 31 MMCF per day, 29 MMCF per day and 6 MMCF per day, respectively, in 2004. These increases were partially offset by lower production volumes in Canada of 48 MMCF per day. Production volumes in Canada were down primarily due to higher service costs and the Canadian dollar strengthening against the U.S. dollar that led to fewer net wells drilled in 2004 versus 2003, unfavorable weather conditions that impacted program execution during 2004 and lower than expected new well productivity in certain areas. Average NGLs sales volumes increased 0.5 MBbls per day in 2004, resulting in higher revenues of $5 million over 2003.

Below is a discussion of total costs and other income net.
Total Costs and Other Income Net

Year Ended December 31,	2004	2003	2002	2004 vs. 2003 Increase (Decrease)	2004 vs. 2003 % Increase (Decrease)
		($ In Millions)			
Costs and other income net					
Taxes other than income taxes	$ 260	$ 187	$ 123	$ 73	39%
Transportation expense	453	408	354	45	11
Operating costs	587	475	467	112	24
Depreciation, depletion and amortization	1,137	927	833	210	23
Exploration costs	258	252	286	6	2
Impairment of oil and gas properties	90	63		27	43
Administrative	215	164	161	51	31
Interest expense	282	260	274	22	8
(Gain)/loss on disposal of assets	13	(8)	(68)	(21)	(263)
Other expense (income) net	19	13	(31)	6	46
Total costs and other income net	**$3,314**	**$2,741**	**$2,399**	**$573**	**21%**

Total costs and other income net increased $573 million in 2004. This increase in total costs and other income net was primarily due to the items discussed below. The increase in the exchange rate in Canada during 2004 impacted certain costs and expenses for the Company. Changes in the value of the Canadian dollar versus the U.S. dollar could impact costs and expenses in future years. However, at this time, the Company cannot predict what impact the Canadian exchange rate will have on costs and expenses in the future.

DD&A expense increased $210 million primarily due to higher production and higher unit-of-production rates on International properties and higher unit-of-production rates on Canadian properties. Operating costs increased $112 million compared to 2003. This increase is primarily due to higher well operating expenses, which include direct expenses incurred to operate the Company s wells and equipment on producing leases. Well operating expenses were higher primarily due to increased repair and maintenance expenses, higher workover activity and changes in exchange rates.

Taxes other than income taxes increased $73 million primarily due to higher production taxes resulting from higher crude oil and natural gas revenues. Taxes other than income taxes include severance taxes which are directly correlated to natural gas and crude oil revenues. Administrative expense increased $51 million primarily due to higher stock-based compensation expense, excluding stock options, related to a higher stock price for the Company and higher legal expenses. Transportation expense increased $45 million primarily due to operations related to new start-up projects in late 2003 in International operations and higher rates in Canada. Interest expense increased $22 million primarily due to no capitalized interest incurred on capital projects in 2004.

The Company performs an impairment analysis annually for unproved reserves or whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable. Cash flows used in the impairment analysis are determined based upon management s estimates of natural gas, NGLs and

crude oil reserves, future natural gas, NGLs and crude oil prices and costs to extract these reserves. In 2004 and 2003, the Company recorded non-cash charges of $90 million and $63 million, respectively, related to the impairment of oil and gas properties. The impairments in 2004 and 2003 were related to undeveloped properties in Canada and performance-related downward reserve adjustments, also primarily in Canada, respectively.
Exploration costs increased $6 million due to higher geological and geophysical and other expenses of $20 million partially offset by lower amortization of undeveloped lease costs of $10 million and lower exploratory dry hole costs of $4 million. Exploration expense fluctuates 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. Of the exploratory wells drilled by the Company in 2004, 2003 and 2002, the Company experienced a success rate in the range of approximately 50 to 66 percent during that period of time. These success rates are not necessarily indicative of future rates. The Company capitalizes costs incurred to drill exploratory wells pending determination of whether the wells have found an adequate amount of economically recoverable reserves to be classified as proved. When a determination cannot be made at the time drilling is completed, the costs are deferred until a determination can be made. At December 31, 2004, $23 million of deferred exploration costs were included in oil and gas properties on the Company s Consolidated Balance Sheet. Some or all of these costs could be included in exploration expense in future periods. In 2004 and 2003, $14 million and $7 million, respectively, were reclassified from oil and gas properties to exploration expense.

Income Tax Expense

Income tax expense increased $467 million in 2004, primarily due to an increase in pretax income of $734 million. In 2004, the Company recorded $26 million of U.S. income tax expense related to its plan to repatriate $500 million in 2005 of eligible foreign earnings under the one-time provisions of the American Job Creation Act of 2004. In addition, income taxes on foreign earnings in excess of the U.S. tax rate resulted in an increase in tax expense of $19 million in 2004. The reduction of the Canadian federal statutory income tax rate resulted in lower income tax benefits of $158 million in 2004 compared to 2003. The reduction of the Alberta provincial corporate income tax rate resulted in higher income tax benefits of $12 million in 2004 compared to 2003. The Company also recorded a net tax benefit of $10 million in 2004 related to the settlement of the 1999-2000 audits of its Section 29 Tax Credits, and recorded a net tax benefit of $27 million in 2003 related to the settlements of the 1996-1998 audits of its Section 29 Tax Credits. As a result of the increase in exchange rates, the Company recorded higher tax benefits of $7 million related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly-owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada. Substantially all of the increase in the tax benefit of the cross-border financing deduction from 2003 to 2004 was due to the strengthening of the Canadian dollar. This benefit is not expected to fluctuate in the future for reasons other than changes in exchange rate and debt levels.

Legal Proceedings

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 analyzed the potential impact of the Amoco ruling and determined that, if upheld, the decision will have a negative impact on 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.

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 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 court certified the plaintiff classes of royalty and overriding royalty interest owners, and trial by jury commenced on October 10, 2005, during which plaintiffs sought monetary damages of up to $42 million in principal, plus $311 million in interest, and unspecified punitive damages and attorney s fees. The Company presented substantial defenses to these claims. In a separate action, the Company and El Paso Natural Gas Company asserted contractual claims for indemnity against each other. On November 9, 2005, the parties counsel entered into a preliminary agreement to settle this lawsuit for $66 million, plus interest on this amount commencing January 20, 2006, as provided in the settlement agreement. On January 20, 2006, the Court preliminarily approved the settlement and scheduled a fairness hearing to determine the fairness to class members of the proposed settlement, which is scheduled to commence in May 2006. The Company and El Paso Natural Gas Company have reached a preliminary agreement to settle the contractual indemnity claims against each other. The settlement of the indemnity claims is subject to final court approval of the class action settlement. Upon final court approval of the class action settlement, the Company s contribution to the settlement will be approximately $36 million, plus interest from January 20, 2006, as provided in the settlement agreement. The Company has established a reserve to provide for this potential liability based upon management s evaluation of this matter.

The Company and its directors have been named defendants in a lawsuit styled *Jeffrey Halpern, Derivatively on Behalf of Burlington Resources Inc., Plaintiff, vs. Bobby S. Shackouls, et al., and Burlington Resources Inc. a Delaware Corporation, Nominal Defendant,* Cause No. 2005-79250, filed on December 15, 2005, in the 215th Judicial District Court of Harris County, Texas (Halpern case) and also named as defendants in a lawsuit styled *Charles Conrardy, On Behalf of Himself and All Others Similarly Situated, Plaintiff, vs. Burlington Resources Inc., et al.*, Cause No. 2005-79267, filed on December 16, 2005, in the 165th Judicial District Court of Harris County, Texas (Conrardy case). Both lawsuits allege that Company s board of directors breached its fiduciary duties in approving the proposed merger announced on December 12, 2005, between the Company and ConocoPhillips. The Halpern case is a stockholder derivative action purportedly filed on behalf of the Company against the Company s board of directors, and contains claims for abuse of control, breach of the duty of candor, gross mismanagement, waste and unjust enrichment, and breach of fiduciary duty. The Conrardy case is a purported stockholder class action lawsuit against the Company and the Company s board of directors, and contains a claim for breach of fiduciary duty. Both petitions allege, among other things, that the Company s board of directors engaged in self dealing by approving a proposed merger that allegedly advances the Company s board of directors personal interests at the expense of the Company s stockholders, thus causing the Company s stockholders to receive an unfair price for their shares of the Company s common stock. Both petitions seek, among other things, an injunction preventing the completion of the merger, rescission if the merger is consummated, attorneys fees and expenses associated with the lawsuit, and any other further equitable relief as the courts may deem just and proper. The Company believes these actions are without merit and intends to defend them vigorously. The Company has not established a reserve for these matters.

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.

At December 31, 2005, the Company s Consolidated Balance Sheet included reserves for legal proceedings of $137 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, the Company believes 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.

Other Matters

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. The Company adopted SFAS No. 154 on 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 March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143* (Interpretation). This Interpretation clarifies that the term *conditional asset retirement obligation* as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This Interpretation is effective for the Company s year ended December 31, 2005. The adoption of this Interpretation did not impact the Company s consolidated financial position or results of operations.

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 December 15, 2005. The Company adopted 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 will result in the Company recording an expense of approximately $10 million in 2006.

In September 2005, the FASB issued EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue). This Issue addresses the accounting for purchase and sales arrangements with the same party and is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first interim or annual reporting period beginning after March 15, 2006. The adoption of this Issue is not expected to have a material impact on the Company s consolidated financial position or results of operations.

Safe Harbor Cautionary Disclosure on Forward-Looking Statements

The Company, in discussions of its future plans, expectations, objectives and anticipated performance in periodic reports filed by the Company with the SEC (or documents incorporated by reference therein) may include projections or other forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by the words expects, anticipates, intends, plans, believes, should and similar expression

Projections and forward-looking statements are based on assumptions which the Company believes are reasonable, but are by their nature inherently uncertain. In all cases, there can be no assurance that such assumptions will prove correct or that projected events will occur, and actual results could differ materially from those projected. See Risk Factors on pages 12-14 for some of the important factors that could cause actual results to differ from any such projections.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2005. In making this assessment, the Company s management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.* Based on our assessment, management has concluded that, as of December 31, 2005, the Company s internal control over financial reporting was effective based on those criteria. The Company s independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited our assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, as stated in their report which appears on page 39.

Bobby S. Shackouls Chairman of the Board, President and Chief Executive Officer	Joseph P. McCoy Senior Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
of Burlington Resources Inc.:

We have completed integrated audits of Burlington Resources Inc. s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the index appearing under Item Fifteen present fairly, in all material respects, the financial position of Burlington Resources Inc. and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 10 to the consolidated financial statements, on January 1, 2003, the Company changed its method of accounting for its asset retirement obligations in connection with its adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in the Management Report on Internal Control Over Financial Reporting appearing under Item Seven, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Houston, Texas
February 28, 2006

ITEM EIGHT

FINANCIAL STATEMENTS AND SUPPLEMENTARY FINANCIAL INFORMATION

BURLINGTON RESOURCES INC.

CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31,	**2005**	**2004**	**2003**
	(In Millions, Except per Share Amounts)		
REVENUES	**$7,587**	**$5,618**	**$4,311**
COSTS AND OTHER INCOME NET			
Taxes Other than Income Taxes	355	260	187
Transportation Expense	496	453	408
Operating Costs	697	587	475
Depreciation, Depletion and Amortization	1,313	1,137	927
Exploration Costs	293	258	252
Impairment of Oil and Gas Properties	50	90	63
Administrative	256	215	164
Interest Expense	281	282	260
(Gain)/Loss on Disposal of Assets	(240)	13	(8)
Other Expense Net	38	19	13
Total Costs and Other Income Net	**3,539**	**3,314**	**2,741**
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	4,048	2,304	1,570
Income Tax Expense	1,338	777	310
Income Before Cumulative Effect of Change in Accounting Principle	2,710	1,527	1,260
Cumulative Effect of Change in Accounting Principle Net			(59)
Net Income	**$2,710**	**$1,527**	**$1,201**
EARNINGS PER COMMON SHARE			
Basic			
Before Cumulative Effect of Change in Accounting Principle	$ 7.13	$ 3.90	$ 3.17
Cumulative Effect of Change in Accounting Principle Net			(0.15)
Net Income	**$ 7.13**	**$ 3.90**	**$ 3.02**
Diluted			
Before Cumulative Effect of Change in Accounting Principle	$ 7.07	$ 3.86	$ 3.15
Cumulative Effect of Change in Accounting Principle Net			(0.15)
Net Income	**$ 7.07**	**$ 3.86**	**$ 3.00**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET

December 31,	2005	2004
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 3,528	$ 2,179
Accounts Receivable	1,444	947
Inventories	140	124
Other Current Assets	258	158
	5,370	3,408
Oil and Gas Properties (Successful Efforts Method)	20,669	17,943
Other Properties	1,669	1,544
	22,338	19,487
Less: Accumulated Depreciation, Depletion and Amortization	9,900	8,454
Properties Net	12,438	11,033
Goodwill	1,089	1,054
Other Assets	328	249
Total Assets	**$19,225**	**$15,744**
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 1,730	$ 1,125
Taxes Payable	271	264
Accrued Interest	61	61
Dividends Payable	38	33
Other Current Liabilities	116	59
	2,216	1,542
Long-term Debt	3,893	3,887
Deferred Income Taxes	3,038	2,396
Other Liabilities and Deferred Credits	1,143	908
Commitments and Contingent Liabilities (Note 14)		

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 for 2005 and 2004)	5	5
Paid-in Capital	3,998	3,973
Retained Earnings	6,732	4,163
Deferred Compensation Restricted Stock	(16)	(14)
Accumulated Other Comprehensive Income	1,244	1,092
Cost of Treasury Stock (107,074,368 and 94,435,401 Shares for 2005 and 2004, respectively)	(3,028)	(2,208)
Stockholders Equity	8,935	7,011
Total Liabilities and Stockholders Equity	**$19,225**	**$15,744**

See accompanying Notes to Consolidated Financial Statements.

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BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

Year Ended December 31,	2005	2004	2003
		(In Millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 2,710	$ 1,527	$ 1,201
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	1,313	1,137	927
Deferred Income Taxes	503	371	150
Exploration Costs	293	258	252
Impairment of Oil and Gas Properties	50	90	63
(Gain)/Loss on Disposal of Assets	(240)	13	(8)
Changes in Derivative Fair Values	(1)	(5)	(5)
Cumulative Effect of Change in Accounting Principle Net			59
Working Capital Changes			
Accounts Receivable	(481)	(365)	(28)
Inventories	(29)	(40)	(26)
Other Current Assets	(24)	(25)	(15)
Accounts Payable	384	278	(4)
Taxes Payable	77	188	(9)
Accrued Interest			(1)
Other Current Liabilities	(10)	18	
Changes in Other Assets and Liabilities	(9)	(9)	(17)
Net Cash Provided by Operating Activities	4,536	3,436	2,539
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Properties	(2,469)	(1,582)	(1,899)
Proceeds from Sales and Other	183	(25)	4
Net Cash Used in Investing Activities	(2,286)	(1,607)	(1,895)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-term Debt		41	
Reduction in Long-term Debt	(2)	(41)	(75)
Dividends Paid	(136)	(122)	(85)
Common Stock Purchases	(911)	(518)	(356)
Common Stock Issuances	64	153	128
Other		(1)	(3)
Net Cash Used in Financing Activities	(985)	(488)	(391)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	84	81	61

Increase in Cash and Cash Equivalents	1,349	1,422	314
Cash and Cash Equivalents			
Beginning of Year	2,179	757	443
End of Year	**$ 3,528**	**$ 2,179**	**$ 757**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Restricted Stock	Accumulated Other Comprehensive Income (Loss)	Cost of Treasury Stock	Stockholders Equity
	(In Millions, Except Share Data)						
December 31, 2002	$5	$3,938	$1,675	$ (9)	$ (164)	$(1,613)	$3,832
Comprehensive Income							
Net Income			1,201				1,201
Foreign Currency Translation					802		802
Hedging Activities					11		11
Minimum Pension Liability					6		6
Comprehensive Income			1,201		819		2,020
Cash Dividends Declared ($0.29 per Share)			(115)				(115)
Common Stock Purchases (14,829,980 Shares)						(361)	(361)
Stock Option Activity		5				129	134
Issuance of Restricted Stock				(12)		12	
Amortization of Restricted Stock				11			11
December 31, 2003	5	3,943	2,761	(10)	655	(1,833)	5,521
Comprehensive Income							
Net Income			1,527				1,527
Foreign Currency Translation					396		396
Hedging Activities					41		41
Comprehensive Income			1,527		437		1,964
Cash Dividends Declared ($0.32 per Share)			(125)				(125)
						(522)	(522)

Common Stock Purchases (14,358,000 Shares)							
Stock Option Activity		30				132	162
Issuance of Restricted Stock				(15)		15	
Amortization of Restricted Stock				11			11
December 31, 2004	5	3,973	4,163	(14)	1,092	(2,208)	7,011
Comprehensive Income							
Net Income			2,710				2,710
Foreign Currency Translation					232		232
Hedging Activities					(79)		(79)
Minimum Pension Liability					(1)		(1)
Comprehensive Income			2,710		152		2,862
Cash Dividends Declared ($0.37 per Share)			(141)				(141)
Common Stock Purchases (15,734,600 Shares)						(902)	(902)
Stock Option Activity		25				66	91
Issuance of Restricted Stock				(16)		16	
Amortization of Restricted Stock				14			14
December 31, 2005	**$5**	**$3,998**	**$6,732**	**$ (16)**	**$ 1,244**	**$(3,028)**	**$8,935**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Accounting Policies

Nature of Business

Burlington Resources Inc. (BR) is among the world s largest independent oil and gas companies and holds one of the industry s leading positions in North American natural gas reserves and production. BR conducts exploration, production and development operations in the U.S., Canada, the United Kingdom, the Netherlands, North Africa, China and South America. Its extensive North American lease holdings extend from the U.S. Gulf Coast to Northeast British Columbia and Northern Alberta in Canada. BR is a holding company and its principal subsidiaries include Burlington Resources Oil & Gas Company LP, The Louisiana Land and Exploration Company (LL&E), Burlington Resources Canada Ltd., Burlington Resources Canada (Hunter) Ltd. (formerly known as Canadian Hunter Exploration Ltd.) (Hunter), and their affiliated companies (collectively, the Company).

Pending Merger

On December 12, 2005, BR and ConocoPhillips entered into a definitive agreement under which ConocoPhillips will acquire BR. Upon completion of the merger, the Company will be merged into a wholly owned subsidiary of ConocoPhillips and its separate corporate existence will cease. Under the terms of the agreement, BR shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each BR share they own. The transaction is subject to BR shareholder and regulatory approval and other customary terms and conditions. All options to purchase BR common stock granted under BR s equity compensation plans that are outstanding at December 31, 2005 will vest and become fully exercisable upon the completion of the merger and will be converted into options to purchase ConocoPhillips common stock. In addition, the restrictions on all shares of restricted BR common stock granted under BR s equity compensation plans that are outstanding at December 31, 2005 will lapse upon completion of the merger, and the shares will be converted into rights to receive the per share merger consideration.

Principles of Consolidation and Reporting

The consolidated financial statements of the Company include the accounts of BR and its majority-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. Investments in entities in which the Company has a significant ownership interest, generally 20 to 50 percent, or otherwise does not exercise control, are accounted for using the equity method. Under the equity method, the investments are stated at cost plus the Company s equity in undistributed earnings and losses. The consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income or stockholders equity.

Cash and Cash Equivalents

All short-term investments purchased with a maturity of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates market value.

Inventories

Inventories of materials, supplies and products are valued at the lower of average cost or market. Inventories consisted of the following.

December 31,	**2005**	**2004**
	(In Millions)	
Materials and supplies	$113	$ 99
Product inventory	27	25

Inventories	$140	$124

Properties

Proved

Oil and gas properties are accounted for using the successful efforts method. Under this method, all development costs and acquisition costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

The Company evaluates the impairment of its proved oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value if

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

the expected undiscounted future cash flows are less than the asset s net book value. Cash flows are determined based upon reserves using prices and costs consistent with those used for internal decision making. The underlying commodity prices embedded in the Company s estimated cash flows are the product of a process that begins with the New York Mercantile Exchange pricing and adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Given that spot hydrocarbon market prices are subject to volatile changes, it is the Company s opinion that a long-term look at market prices will lead to a more appropriate valuation of long-term assets.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major replacements and renewals are capitalized. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. See Note 10 of Notes to Consolidated Financial Statements.

Unproved

Unproved properties consist of costs incurred to acquire unproved leases (lease acquisition costs) as well as costs incurred to acquire unproved reserves. Unproved lease acquisition costs are capitalized and amortized on a composite basis, based on past success, experience and average lease-term lives. Unamortized lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The book value of the Company s unproved reserves, which were acquired in connection with business acquisitions, was determined using the same methods, after adjusting for risks, that were used to value the proved reserves acquired in the same acquisition. Because these reserves do not meet the strict definition of proved reserves, the related costs are not classified as proved properties. As the unproved reserves are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved reserves for impairment annually by comparing book value to fair value, which is determined using discounted estimates of future cash flows. See Note 16 of Notes to Consolidated Financial Statements.

Exploration

Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after completing or drilling the well, however, in certain situations determination cannot be made when drilling is completed. The Company defers capitalized exploratory drilling costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells in progress as long as development is underway, is firmly planned for the near future or the necessary approvals are actively being sought. For all other exploratory wells, determination is made within one year from the date drilling and other necessary activities have been completed. If a determination cannot be made after one year, all costs associated with the well are expensed. See Note 5 of Notes to Consolidated Financial Statements.

Other

Other properties include gas plants, pipelines, buildings, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using either the straight-line method based on expected lives of the individual assets or group of assets or the unit-of-production method over the remaining life of related proved reserves.

Goodwill

Goodwill represents the excess of the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed. The Company accounts for its goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets,* which requires the Company to test goodwill for impairment annually or whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, rather than amortize.

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

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest. The Company records its entitled share of revenues based on entitled volumes and contracted sales prices. The sales price for natural gas, NGLs and crude oil are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents. Historically, these adjustments have been insignificant. Since there is a ready market for natural gas, crude oil and NGLs, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. As a result, the Company maintains a minimum amount of product inventory in storage. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess (overproduction) of the Company s share is treated as a liability. If the Company receives less than it is entitled, the underproduction is recorded as a receivable. At December 31, 2005 and 2004, the Company had imbalance receivables of $64 million and $58 million, respectively and imbalance payables of $64 million and $69 million, respectively. The current portion of the imbalance receivables and payables is included in Accounts Receivable and Accounts Payable, respectively, on the Company s Consolidated Balance Sheet. The long-term portion of imbalance receivables and payables is included in Other Assets and Other Liabilities and Deferred Credits, respectively. At December 31, 2005 and 2004, the long-term portion of imbalance receivables and payables was $52 million and $53 million, and $47 million and $57 million, respectively.

The Company utilizes buy/sell or exchange contracts to transport its crude oil from producing areas to a market center, typically Cushing, Oklahoma. The Company accounts for these transactions on a net basis in its Consolidated Statement of Income.

Royalty Payable

It is the Company s policy to calculate and pay royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Accounts Payable on the Company s Consolidated Balance Sheet.

Foreign Currency Translation

The assets, liabilities and operations of BR s Canadian operating subsidiaries are measured using the Canadian dollar as the functional currency. These assets and liabilities are translated into United States (U.S.) dollars at end-of-period exchange rates. Gains and losses related to translating these assets and liabilities are recorded in Accumulated Other Comprehensive Income. At December 31, 2005 and 2004, the balances in Accumulated Other Comprehensive Income related to foreign currency translation were gains of $1,304 million and $1,072 million, respectively. Revenue and expenses are translated into U.S. dollars at the average exchange rates in effect during the period. The assets, liabilities and results of operations of BR s International operating subsidiaries are measured using the U.S. dollar as the functional currency. For International subsidiaries where the U.S. dollar is the functional currency, all foreign currency denominated assets and liabilities are remeasured into U.S. dollars at end-of-period exchange rates. Inventories, prepaid expenses and properties are exceptions to this policy and are remeasured at historical rates. Foreign currency revenues and expenses are remeasured at average exchange rates in effect during the year. Exceptions to this policy include all expenses related to balance sheet amounts that are remeasured at historical exchange rates. Exchange gains and losses arising from remeasured foreign currency denominated monetary assets and liabilities are included in Other Expense (Income) Net in the Consolidated Statement of Income. Included in net income for the years ended December 31, 2005, 2004 and 2003 are exchange losses of $31 million, exchange gains of $5 million and exchange losses of $7 million, respectively.

Commodity Hedging Contracts and Other Derivatives

The Company enters into derivative contracts, primarily options and swaps, to hedge future natural gas and crude oil production in order to mitigate the risk of market price fluctuations. The Company also enters into derivative contracts to mitigate the risk of interest rate fluctuations. All derivatives are recognized on the balance sheet and measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in the fair value of the derivative are recognized currently in earnings. If the derivative qualifies for hedge accounting, changes in the fair value of the derivative are either recognized in income along with the corresponding change in fair value of the item being hedged for fair-value hedges or deferred in other comprehensive income to the extent the hedge is effective for cash-flow hedges. To qualify for hedge accounting, the derivative must qualify as either a fair-value, cash-flow or foreign-currency hedge.

The hedging relationship between the hedging instruments and hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively if and when a

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

hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of its derivative instruments. Gains and losses deferred in Accumulated Other Comprehensive Income related to cash-flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. Adjustment to the carrying amounts of hedged items is discontinued in instances where the related fair-value hedging instrument becomes ineffective. The balance in the fair-value hedge adjustment account is recognized in income when the hedged item is sold. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the related hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues and are included in realized prices in the period that the hedged item is sold. Gains and losses on hedging instruments which represent hedge ineffectiveness and gains and losses on derivative instruments which do not qualify for hedge accounting are included in revenues in the period in which they occur. The resulting cash flows are reported as cash flows from operating activities.

Credit and Market Risks

The Company manages and controls market and counterparty credit risk through established formal internal control procedures which are reviewed on an ongoing basis. In the normal course of business, collateral is not required for financial instruments with credit risk. The Company uses the specific identification method of providing allowances for doubtful accounts.

Income Taxes

Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities. Tax credits are accounted for under the flow-through method, which reduces the provision for income taxes in the year the tax credits are earned. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Treasury Stock

The Company follows the weighted-average-cost method of accounting for treasury stock transactions.

Stock-based Compensation

At December 31, 2005, the Company has three stock-based employee compensation plans, which are described in Note 12 of Notes to Consolidated Financial Statements. The Company uses the intrinsic value based method of accounting for stock-based compensation, as prescribed by Accounting Principles Board Opinion No. 25 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 weighted average fair values of options granted during the years 2005, 2004 and 2003 were $8.39, $5.50 and $5.43, respectively. The fair values of employee stock options were calculated using the Black-Scholes stock option valuation model that has been modified to include dividends since the Company has historically paid dividends. Additionally, the Company uses an expected term for stock options rather than the contractual term since they are non-transferable and are typically exercised prior to expiration. The following weighted average assumptions were used for grants in 2005, 2004 and 2003: stock price volatility of 22 percent, 26 percent and 32 percent, respectively; risk free rate of return percent of 3.4 percent, 2.1 percent and 2.4 percent, respectively; dividend yields of 0.61 percent, 0.89 percent and 1.18 percent, respectively; and an expected term of 3 years, 3 years and 4 years, respectively.

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

The following table illustrates the effect on net income and earnings per share had the Company applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation,* to its stock-based employee compensation.

Year Ended December 31,	**2005**	**2004**	**2003**
	(In Millions, Except per Share Amounts)		
Net income as reported	$2,710	$1,527	$1,201
Less: pro forma stock based employee compensation cost, after tax (unaudited)	5	10	10
Net income pro forma (unaudited)	$2,705	$1,517	$1,191
Basic EPS as reported	$ 7.13	$ 3.90	$ 3.02
Basic EPS pro forma (unaudited)	7.12	3.87	2.99
Diluted EPS as reported	7.07	3.86	3.00
Diluted EPS pro forma (unaudited)	$ 7.05	$ 3.84	$ 2.98

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Earnings Per Common Share (EPS)

Basic 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 380 million, 392 million and 398 million for the years ended December 31, 2005, 2004 and 2003, respectively. Diluted EPS reflects the potential dilution that could occur if contracts to issue common stock and related stock options were exercised. The weighted average number of common shares outstanding for computing diluted EPS, including dilutive stock options, was 383 million, 395 million and 400 million for the years ended December 31, 2005, 2004 and 2003, respectively. For the years ended December 31, 2005 and 2003, approximately 5 thousand and 2 million shares, respectively, attributable to the assumed exercise of outstanding options were excluded from the calculation of diluted EPS because the effect was antidilutive. All shares attributable to outstanding options were dilutive for the year ended December 31, 2004. The Company has no preferred stock affecting EPS, and therefore, no adjustments related to preferred stock were made to reported net income in the computation of EPS.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas, NGLs and crude oil reserves and related cash flow estimates used in impairment tests of goodwill and other long-lived assets, estimates of future development, income taxes, dismantlement and abandonment costs, estimates relating to certain natural gas, NGLs and crude oil revenues and expenses as well as estimates of expenses related to legal, environmental and other contingencies. Actual results could differ from those estimates.

2. Property Acquisitions and Divestitures

Property Acquisitions

In the third quarter of 2005, the Company acquired certain oil and gas properties located in the Fort Worth Basin in Texas for approximately $136 million. During 2005, the Company also made acquisitions for other oil and gas properties totaling approximately $192 million in the aggregate.

Sale of Trust Units

During the second half of 2005, the Company sold 16,950,000 units of beneficial interest in the Permian Basin Royalty Trust (Units) held by the Company, generating proceeds, after underwriting fees, of approximately $252 million. The Company recorded a pretax gain of $240 million on these sales. Net proceeds generated from the sale of Units were used primarily for the acquisition of oil and gas properties. At December 31, 2005, $64 million of the net proceeds generated from the sale of Units were on deposit with a third-party intermediary to be used to purchase oil and gas properties during 2006.

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

3. Accounts Receivable

Accounts receivable consisted of the following.

December 31,	2005	2004
	(In Millions)	
Natural gas, NGLs and crude oil sales	$1,248	$790
Joint interest billings	142	99
Income tax receivable	36	35
Gas imbalance	12	11
Other	13	25
	1,451	960
Less: allowance for doubtful accounts	7	13
Accounts receivable	$1,444	$947

4. Goodwill

The entire goodwill balance of $1,089 million at December 31, 2005, which is not deductible for tax purposes, is related to the Company s acquisition of Hunter in December 2001. With the acquisition of Hunter, the Company gained Hunter s significant interest in Canada s Deep Basin, North America s third-largest natural gas field, increased its critical mass and enhanced its position as a leading North American natural gas producer. The Company also obtained the exploration expertise of Hunter s workforce, gained additional cost optimization, increased purchasing power and gained greater marketing flexibility in optimizing sales and accessing key market information. The goodwill was assigned to the Company s Canadian reporting unit which includes all of the Company s Canadian subsidiaries.

The provisions of SFAS No. 142 require that a two-step impairment test be performed annually or whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. The first step of the test for impairment compares the book value of the Company s reporting unit to its estimated fair value. The second step of the goodwill impairment test, which is only required when the net book value of the reporting unit exceeds the fair value, compares the implied fair value of goodwill to its book value to determine if an impairment is required.

The Company performed step one of its annual goodwill impairment test in the fourth quarter of 2005 and determined that the fair value of the Company s Canadian reporting unit exceeded its net book value as of September 30, 2005. Therefore, step two was not required.

The fair value of the Company s Canadian reporting unit was determined using a combination of the income approach and the market approach. Under the income approach, the Company estimated the fair value of the reporting unit based on the present value of expected future cash flows. Under the market approach, the Company estimated the fair value based on market multiples of reserves and production for comparable companies as well as recent comparable transactions.

The income approach is dependent on a number of factors including estimates of forecasted revenue and costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar, or depressed natural gas, NGLs and crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. Under the market approach, the Company makes certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although the Company based its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. In 2005, the Company used a professional valuation services firm to assist in preparing its annual valuation of the Canadian reporting unit.

The following table reflects the changes in the carrying amount of goodwill during the year as it relates to the Canadian reporting unit.

	(In Millions)
December 31, 2004	$1,054
Changes in foreign exchange rates during the period	35
December 31, 2005	$1,089

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

5. Oil and Gas and Other Properties

Oil and gas properties consisted of the following.

December 31,	2005	2004
	(In Millions)	
Proved properties	$19,608	$16,662
Less: Accumulated depreciation, depletion and amortization	9,274	7,882
Proved properties net	10,334	8,780
Unproved properties		
Leasehold acquisition costs	471	536
Unproved reserves	590	745
Less: Accumulated amortization	123	152
Unproved properties net	938	1,129
Oil and gas properties net	$11,272	$ 9,909

Other properties consisted of the following.

December 31,	Depreciable Life-Years	2005	2004
		(In Millions)	
Plants and pipeline systems straight-line	10-20	$ 857	$ 801
Plants unit-of-production		401	338
Land, buildings, improvements and furniture and fixtures	0-40	126	139
Data processing and telecommunications equipment	3-7	200	184
Other	3-15	85	82
		1,669	1,544
Less: Accumulated depreciation		503	420
Other properties net		$1,166	$1,124

The following table reflects the net changes in capitalized exploratory well costs pending proved reserve determination.

	2005	2004	2003
		(In Millions)	

Balance at January 1,	$ 23	$ 29	$ 30
Additions	22	18	8
Reclassifications to proved properties	(4)	(10)	(2)
Charged to expense	(16)	(14)	(7)
Balance at December 31,	$ 25	$ 23	$ 29
Capitalized more than one year since completion of drilling	$	$ 1	$

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

6. Accounts Payable

Accounts payable consisted of the following.

December 31,	2005	2004
	(In Millions)	
Trade payables	$ 144	$ 89
Accrued expenses	1,207	828
Revenues and royalties payable to others	286	123
Accrued payroll	79	56
Gas imbalance	11	12
Other	3	17
Accounts payable	$1,730	$1,125

7. Income Taxes

The jurisdictional components of income before income taxes and cumulative effect of change in accounting principle follow.

Year Ended December 31,	2005	2004	2003
		(In Millions)	
Domestic	$2,483	$1,357	$ 983
Foreign	1,565	947	587
Total	$4,048	$2,304	$1,570

The provision for income taxes follows.

Year Ended December 31,	2005	2004	2003
		(In Millions)	
Current			
Federal	$ 498	$171	$ 84
State	25	43	9
Foreign	312	192	67
	835	406	160
Deferred			
Federal	261	175	85
State	1	(4)	6

Foreign	241	200	59
	503	371	150
Total	$1,338	$777	$310

Reconciliation of the federal statutory income tax rate to the effective income tax rate follows.

Year Ended December 31,	**2005**	**2004**	**2003**
U.S. statutory rate	35.0%	35.0%	35.0%
State income taxes (net of federal benefit)	0.4	1.0	0.6
Taxes on foreign income in excess of U.S. statutory rate	2.9	3.6	3.9
Effect of change in foreign income tax rate(1)	(1.3)	(2.9)	(13.6)
Section 29 tax credits(2)		(0.4)	(1.7)
Cross-border financing benefit(3)	(2.8)	(4.5)	(6.2)
Other(4)	(1.1)	1.9	1.7
Effective rate	33.1%	33.7%	19.7%

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

(1) In 2003, the government of Canada passed Bill C-48 that reduced the Canadian federal statutory income tax rate for companies in the natural resource sector. The rate reduction takes effect over a five-year period from 2003 to 2007 and resulted in benefits to the Company of $51 million (1.3%), $23 million (1.0%) and $203 million (12.9%) in 2005, 2004 and 2003, respectively. The Company also recorded a benefit of $45 million (1.9%) and $11 million (0.7%) in 2004 and 2003, respectively, due to reductions in the Alberta provincial corporate income tax rate in Canada.

(2) In 2004, a tax benefit associated with Section 29 Tax Credits was provided in the amount of $10 million (0.4%) as a result of the finalization of the 1999-2000 federal income tax audits. In 2003, a tax benefit associated with Section 29 Tax Credits was provided in the amount of $27 million (1.7%) as a result of an appeal proceeding related to the 1996-1998 income tax audits.

(3) The Company recorded benefits of $112 million (2.8%), $104 million (4.5%) and $97 million (6.2%) in 2005, 2004 and 2003, respectively, related to interest deductions allowed in both the U.S. and Canada. The deduction for interest on the cross-border financing is allowable in both the U.S. and Canada because the issuer of the debt is a wholly owned finance subsidiary of the Company and the activities of the finance subsidiary are taxable in both the U.S. and Canada.

(4) In 2005 and 2004, the Company recorded a tax benefit of $40 million (0.98%) and an income tax expense of $12 million (0.53%), respectively, related to return as filed adjustments. In 2004, the Company recorded a U.S. tax liability of $26 million (1.1%) related to the planned repatriation of $500 million of eligible foreign earnings to the U.S. in 2005 under the one-time provisions of the American Jobs Creation Act of 2004.

Deferred income tax liabilities (assets) follow.

December 31,	**2005**	**2004**
	(In Millions)	
Deferred income tax liabilities		
Property, plant and equipment	$2,310	$2,175
Financial accruals and other	793	573
	3,103	2,748
Deferred income tax assets		
Alternative minimum tax (AMT) credit carryforward		(161)
Foreign net operating loss carryforward	(133)	(171)
Commodity hedging contracts and other derivatives	(36)	13
	(169)	(319)
Less: valuation allowance	35	15
	2,969	2,444
Less: current portion (asset) liability	(69)	48

Deferred income taxes	$3,038	$2,396

At December 31, 2005 and 2004, $69 million and $48 million, respectively, of the net deferred income tax (asset) liability is classified as current and is included in Other Current Assets and Taxes Payable, respectively, on the Company s Consolidated Balance Sheet. The net deferred income tax liabilities at December 31, 2005 and 2004 include deferred state income tax liabilities of approximately $51 million for both years. The net deferred income tax liabilities also include foreign tax liabilities of approximately $2,192 million and $1,872 million at December 31, 2005 and 2004, respectively.

No deferred U.S. income tax liability has been recognized on undistributed earnings of certain foreign subsidiaries as they have been deemed permanently invested outside the U.S., and it is not practicable to estimate the deferred tax liability related to such undistributed earnings. At December 31, 2005, undistributed earnings for which a U.S. deferred income tax liability has not been recognized total $2,049 million. On October 27, 2005, the Company repatriated $500 million of eligible foreign earnings to the U.S. Company under the one-time provisions of the American Jobs Creation Act of 2004. Excluded from undistributed earnings at December 31, 2005 are permanent differences of $1,195 million that would result in taxable income in the U.S. if an amount greater than the retained earnings of the Company s Canadian subsidiaries was distributed to the U.S.

Of the tax benefits for operating loss carryforwards, all of which relate to foreign jurisdictions, $109 million has no expiration date, $17 million will expire in the next four to five years, and $7 million will expire in 2015.

8. Commodity Hedging Contracts and Other Derivatives

The Company uses derivative instruments to manage risks associated with natural gas and crude oil price volatility as well as interest rate fluctuations. Derivative instruments that meet the hedge criteria in SFAS No. 133 are designated as cash-flow hedges

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

or fair-value hedges. Derivative instruments that do not meet the hedge criteria in SFAS No. 133 are not designated as 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.

Cash-Flow Hedges

At December 31, 2005, the Company s cash-flow hedges consist of fixed-price swaps and producer collars (purchased put options and written call options). The fixed-price swap agreements are used to fix the prices of anticipated future natural gas production. The producer collars are used to establish floor and ceiling prices on anticipated future natural gas and crude oil production. There were no net premiums received when the Company entered into these option agreements.

Fair-Value Hedges

At December 31, 2005, the Company s fair-value hedges consist of commodity price swaps and interest rate swaps. The Company s commodity price swaps are used to hedge against changes in the fair value of unrecognized firm commitments representing physical contracts that require the delivery of a specified quantity of natural gas or crude oil at a fixed price over a specified period of time. The swap agreements allow the Company to receive market prices for the committed specified quantities included in the physical contracts.

At December 31, 2005, the Company has interest rate swap agreements with an aggregate notional amount of $50 million related to principal amounts of $50 million, 5.6% Notes due December 1, 2006. The objective of these transactions is to protect the designated debt against changes in fair value due to changes in the benchmark interest rate, which was designated as six-month LIBOR. Under the interest rate swap agreements, the Company receives a fixed rate equal to 5.6% per annum and pays the benchmark interest rate plus 3.36 percent. Interest expense on the debt is adjusted to reflect payments made or received under the hedge agreements.

As of December 31, 2005, the Company had the following commodity related derivative instruments outstanding with average underlying prices that represent hedged prices of commodities at various market locations.

			Notional Amount			**Fair Value**
Settlement Period	**Derivative Instrument**	**Hedge Strategy**	**Gas (MMBTU)**	**Oil (Barrels)**	**Average Underlying Prices**	**Asset (Liability)** (In Millions)
2006	Swap	Cash flow	5,844,500		$ 7.59	$ (28)
	Purchased put	Cash flow	64,006,657		7.83	27
	Written call	Cash flow	64,006,657		9.94	(80)
	Purchased put	Cash flow		3,795,000	51.81	5
	Written call	Cash flow		3,795,000	66.41	(15)
	Swap	Fair value	457,000		10.96	(1)
	N/A	Fair value (obligation)	457,000		11.02	1
2007	Swap	Cash flow	1,013,000		3.83	(5)
	Swap	Fair value	136,000		10.01	

	N/A	Fair value (obligation)	136,000	$10.90	
					$(96)

As of December 31, 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)
2006	Interest rate swap	Fair value	$ 50	5.6%	LIBOR + 3.36%	$(1)

The derivative assets and liabilities represent the market values of the Company s derivative instruments as of December 31, 2005. During the years ended 2005, 2004 and 2003, hedging activities related to cash settlements decreased revenues $189 million, $40 million and $63 million, respectively. In addition, during 2005, 2004 and 2003, losses of $2 million, gains of $2 million, and losses of $200 thousand, respectively, were recorded in revenues associated with ineffectiveness of cash-flow and fair-value

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

hedges. During 2005, 2004 and 2003, losses of $1 million, gains of $1 million and $9 million, respectively, were recorded in revenues related to changes in fair value of derivative instruments not designated as hedging instruments.

Changes in other comprehensive income (loss) for the three years ended December 31, 2005 follow.

	(In Millions)
Accumulated other comprehensive loss on hedging activities December 31, 2002	$ (32)
Reclassification adjustments for settled contracts	39
Current period changes in fair value of settled contracts	(18)
Changes in fair value of outstanding hedging positions	(10)
Accumulated other comprehensive loss on hedging activities December 31, 2003	(21)
Reclassification adjustments for settled contracts	24
Current period changes in fair value of settled contracts	(8)
Changes in fair value of outstanding hedging positions	25
Accumulated other comprehensive income on hedging activities December 31, 2004	20
Reclassification adjustments for settled contracts	114
Current period changes in fair value of settled contracts	(135)
Changes in fair value of outstanding hedging positions	(58)
Accumulated other comprehensive loss on hedging activities December 31, 2005	$ (59)

Based on commodity prices and foreign exchange rates as of December 31, 2005, the Company expects to reclassify losses of $90 million ($56 million after tax) to earnings from the balance in Accumulated Other Comprehensive Income during the next twelve months. At December 31, 2005, the Company had derivative assets of $2 million and derivative liabilities of $99 million of which $2 million, $94 million and $5 million is included in Other Current Assets, Other Current Liabilities and Other Liabilities and Deferred Credits, respectively, on the Consolidated Balance Sheet.

9. Long-term Debt

Long-term debt follows.

December 31,	**2005**	**2004**
	(In Millions)	
Notes, 5.60%, due 2006	$ 500	$ 500
Notes, 6.60%, due 2007(1)	129	124
Notes, 5.70%, due 2007	350	350
Debentures, $9^{7}/8$%, due 2010	150	150
Notes, 6.50%, due 2011	500	500
Notes, 6.68%, due 2011	400	400
Notes, 6.40%, due 2011	178	178

Debentures, 7 5/8%, due 2013	100	100
Debentures, 9 1/8%, due 2021	150	150
Debentures, 7.65%, due 2023	88	88
Debentures, 8.20%, due 2025	150	150
Debentures, 6 7/8%, due 2026	67	67
Debentures, 7 3/8%, due 2029	92	92
Notes, 7.20%, due 2031	575	575
Notes, 7.40%, due 2031	500	500
Capital lease	4	6
Discounts and other	(38)	(41)
Total debt	3,895	3,889
Less current maturities	2	2
Total long-term debt	$3,893	$3,887

(1) Notes are denominated in Canadian dollars and reported in U.S. dollars.

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

The Company has debt maturities of $502 million due in 2006, $480 million due in 2007, $1 million due in 2008, $150 million due in 2010, and $2,800 million due in 2011 and thereafter. The fair value of debt outstanding as of December 31, 2005 and 2004 was $4,489 million and $4,528 million, respectively.

Burlington Resources Capital Trust I, Burlington Resources Capital Trust II (collectively, the Trusts), BR and Burlington Resources Finance Company (BRFC) have a shelf registration of $1,500 million 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.

The Company has a $1.5 billion revolving credit facility (Credit Facility) that includes (i) a US$500 million Canadian subfacility 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 December 31, 2005, there were no amounts outstanding under the Credit Facility and no outstanding commercial paper.

At the Company s option, interest on borrowings under the Credit Facility is based on the prime rate, Eurodollar rates or absolute rates. The Canadian subfacility bears interest at rates based on prime, Eurodollar or absolute rates also at the Company s option. The Company also has the option under the Canadian subfacility to request borrowings by way of bankers acceptances.

The Company s access to funds from its Credit Facility is not restricted under any material adverse condition clauses. These clauses typically remove the obligation of the lenders to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower s financial condition, operations or properties considered as a whole, the borrower s ability to make timely debt payments, or the enforceability of material items of the credit agreement. While the Company s Credit Facility includes a covenant that requires the Company to report litigation or a proceeding that the Company has determined is likely to have a material adverse effect on the consolidated financial condition of the Company, the obligation of the lenders to fund the Credit Facility is not conditioned on the absence of such notice of litigation or proceeding.

The Company has a closed deferred compensation plan funded by Company-owned life insurance policies that were entered into by LL&E prior to being acquired by BR. Outstanding borrowings of $173 million and $160 million as of December 31, 2005 and 2004, respectively, on these life insurance policies were reported as a reduction to the cash surrender value and are included as a component of Other Assets on the Company s Consolidated Balance Sheet.

10. Asset Retirement Obligations

On January 1, 2003, the Company adopted SFAS No. 143, *Asset Retirement Obligations.* SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset is allocated to expense through depreciation or depletion of the asset. The majority of the Company s asset retirement obligations relate to plugging and abandoning oil and gas wells and related equipment as well as dismantling plants. During the first quarter of 2003, the Company recorded a net-of-tax cumulative effect of change in accounting principle charge of $59 million ($95 million before tax), increased long-term liabilities $191 million, net properties $96 million and deferred tax assets $36 million in accordance with the transition provisions of SFAS No. 143. There was no impact on the Company s cash flows as a result of adopting SFAS No. 143. The asset retirement obligations, which are included on the Company s Consolidated Balance Sheet in Other Liabilities and Deferred Credits, were $604 million and $468 million at December 31, 2005 and 2004, respectively. Accretion expense for 2005 was $31 million and is included in Depreciation, Depletion and Amortization expense on the Company s Consolidated Statement of Income.

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

The following table reflects the changes in the Company s asset retirement obligations during the current year.

	(In Millions)
Carrying amount of asset retirement obligations as of December 31, 2004	$468
Liabilities incurred during the period	50
Liabilities settled during the period	(15)
Current year accretion expense	31
Revisions in estimated cash flows	73
Changes in foreign exchange rates during the period	(3)
Carrying amount of asset retirement obligations as of December 31, 2005	$604

11. Significant Concentrations

In 2005, 2004 and 2003, approximately 46 percent, 48 percent and 49 percent, respectively, of the Company s natural gas production was transported through pipeline systems owned by El Paso Natural Gas Company (EPNG) and TransCanada Pipelines Limited (TCPL). Mechanical failure and regulatory action at certain points on the EPNG pipeline system could result in a substantial interruption of the transportation of the Company s natural gas production for a limited period of time in the San Juan Basin. TCPL, through its subsidiary, Nova Gas Transmission Ltd., gathers and transports a majority of the Company s Canadian gas production from multiple receipt points to multiple delivery points on their pipeline system. The interruption of gathering or transportation at any individual receipt point or delivery point would not have a material impact on the overall transportation of the Company s Canadian production. The Company takes steps to mitigate these risks through commercial insurance and identification of alternative pipeline transportation. The Company expects to continue to transport a substantial portion of its future natural gas production through these pipeline systems. See Note 14 of Notes to Consolidated Financial Statements for demand charges paid under firm and interruptible transportation capacity rights on pipeline systems.

During the years ended December 31, 2005 and 2004, sales to BP and ConocoPhillips accounted for approximately 11 and 10 percent and 12 and 10 percent, respectively, of the Company s total revenues. During the year ended December 31, 2003, no customer accounted for more than 10 percent of total revenues. Management believes that the loss of either of these customers would not have a material adverse effect on its results of operations or its financial position since the market for the Company s production is highly liquid with other willing buyers, including potential additional sales to existing customers, other than the two named above.

Substantially all of the Company s accounts receivable at December 31, 2005 and 2004 result from sales of natural gas, NGLs and crude oil as well as joint interest billings to third party companies also in the oil and gas industry. This concentration of customers and joint interest owners may impact the Company s overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. At December 31, 2005, 25 percent of the Company s accounts receivable balance was due from five customers.

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

12. Capital Stock

The Company s Common Stock activity follows.

	Number of Shares		
	Issued	Treasury	Outstanding
December 31, 2002	482,377,376	(79,498,862)	402,878,514
Treasury shares purchased		(14,829,980)	(14,829,980)
Shares issued under compensation plans, net of forfeitures		476,168	476,168
Option exercises		6,772,904	6,772,904
December 31, 2003	482,377,376	(87,079,770)	395,297,606
Treasury shares purchased		(14,358,000)	(14,358,000)
Treasury shares cancelled	(506)	506	
Shares issued under compensation plans, net of forfeitures		418,731	418,731
Option exercises		6,583,132	6,583,132
December 31, 2004	482,376,870	(94,435,401)	387,941,469
Treasury shares purchased		(15,734,600)	(15,734,600)
Shares issued under compensation plans, net of forfeitures		313,702	313,702
Option exercises		2,781,931	2,781,931
December 31, 2005	482,376,870	(107,074,368)	375,302,502

Stock Compensation Plans

The Company s 2002 Stock Incentive Plan (2002 Plan) succeeds its 1993 Stock Incentive Plan (1993 Plan) which expired by its terms in April 2002 but remains in effect for options granted prior to April 2002. The 2002 Plan provides for the grant of stock options, restricted stock and stock appreciation rights (collectively, 2002 Awards). Under the 2002 Plan, options may be granted to officers and key employees at fair market value on the date of grant, are exercisable in part by the optionee after completion of at least one year of continuous employment from the grant date and have a term of ten years. The total number of shares of the Company s Common Stock for which 2002 Awards under the 2002 Plan may be granted is 15,000,000. At December 31, 2005, 9,049,370 shares were available for grant under the 2002 Plan.

In 1997, the Company adopted the 1997 Employee Stock Incentive Plan (1997 Plan) from which stock options and restricted stock (collectively, 1997 Awards) may be granted to employees who are not eligible to participate in the plans adopted for officers and key employees. The options are granted at fair market value on the grant date, generally vest ratably over a period of three years from the date of the grant and have a term of ten years. The 1997 Plan was amended during 2002 to limit the maximum number of shares of the Company s Common Stock for which 1997 Awards under the 1997 Plan may be granted after April 2002 to 10,000,000 shares. At December 31, 2005, 8,120,843 shares were available for grant under the 1997 Plan, of which up to 300,000 shares annually may be restricted stock.

The Company issued 363,425 shares, 519,105 shares and 578,850 shares of restricted stock in 2005, 2004 and 2003, respectively, from the 2002 and 1997 Plans. The restrictions on this stock generally lapse on the third anniversary of the date of grant. The weighted average grant-date fair value of restricted stock granted in the years ended December 31, 2005, 2004, and 2003 was approximately $44.77, $29.44 and $21.04, respectively. Related compensation expense of approximately $14 million, $11 million and $11 million was recognized for the years ended December 31, 2005, 2004 and 2003, respectively.

The Company s 2000 Stock Option Plan (2000 Plan) for Non-Employee Directors provides for the annual grant of a nonqualified option of 4,000 shares of the Company s Common Stock immediately following the Annual Meeting of Stockholders to each Director who is not a salaried officer of the Company. In addition, an option for 10,000 shares is granted upon a Director s initial election or appointment to the Board of Directors. The options vest immediately and have a term of 10 years. The exercise price per share with respect to each option is the fair market value, as defined in the 2000 Plan, of the Company s Common Stock on the date the option is granted. The total number of shares of the Company s Common Stock for which options may be granted under the 2000 Plan is 500,000. At December 31, 2005, 214,000 shares were available for grant under the 2000 Plan.

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

The Company s stock option activity follows.

	Options	Weighted Average Exercise Price
December 31, 2002	14,328,428	$21.22
Granted	3,955,780	21.06
Exercised	(6,772,904)	19.44
Cancelled	(562,224)	23.55
December 31, 2003	10,949,080	22.14
Granted	1,910,600	29.48
Exercised	(6,583,132)	22.74
Cancelled	(183,314)	24.00
December 31, 2004	6,093,234	23.75
Granted	1,042,250	44.80
Exercised	(2,781,931)	23.63
Cancelled	(98,285)	28.94
December 31, 2005	4,255,268	$28.87

The following table summarizes information related to stock options outstanding and exercisable at December 31, 2005.

Options Outstanding	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price
472,652	$13.69 $20.31	$17.90	4.3	472,652	$17.90
2,724,366	20.83 29.36	24.77	6.8	2,192,947	25.69
992,500	32.98 44.22	43.70	9.0	48,400	33.63
65,750	49.55 72.58	53.30	9.4	48,000	49.55
4,255,268	$13.69 $72.58	$28.87	7.1	2,761,999	$24.91

Exercisable stock options and weighted average exercise prices at December 31, 2004 and 2003 follow.

	Options Exercisable	Weighted Average Exercise Price

December 31, 2004	3,155,479	$21.57
December 31, 2003	6,797,856	$22.54

Preferred Stock and Preferred Stock Purchase Rights

The Company is authorized to issue 75,000,000 shares of preferred stock, par value $.01 per share. On December 9, 1998, the Company s Board of Directors designated 3,250,000 of the authorized preferred shares as Series A Junior Participating Preferred Stock. Upon issuance, each two-hundredth of a share of Series A Junior Participating Preferred Stock will have dividend and voting rights approximately equal to those of one share of Common Stock of the Company. In addition, on December 9, 1998, the Board of Directors declared a dividend distribution of one Right for each outstanding share of Common Stock of the Company to shareholders of record on December 16, 1998. The Rights become exercisable if, without the Company s prior consent, a person or group acquires securities having 15 percent or more of the voting power of all of the Company s voting securities (an Acquiring Person) or ten days following the announcement of a tender offer which would result in such ownership. Each Right, when exercisable, entitles the registered holder to purchase from the Company two-hundredth of a share of Series A Junior Participating Preferred Stock at a price of $200 per two-hundredth of a share, subject to adjustment. If, after the Rights become exercisable, the Company were to be involved in a merger or other business combination in which its Common Stock was exchanged or changed or 50 percent or more of the Company s assets or earning power were sold, each Right would permit the holder to purchase, for the exercise price, stock of the acquiring company having a value of twice the exercise price. In addition, except for certain permitted offers, if any person or group becomes an Acquiring Person, each Right would permit the purchase, for the exercise price, of

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

Common Stock of the Company having a value of twice the exercise price. Rights owned by an Acquiring Person are void. The Rights may be redeemed by the Company under certain circumstances until their expiration date for $.01 per Right.

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. Hunter 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 has discretionary defined contribution savings plans (401(k) Plan in the U.S.). Under the 401(k) Plan, an employee may elect to contribute from 1 to 13 percent of his/her eligible compensation subject to an Internal Revenue Service limit of $14,000 in 2005. The Company matches, with cash, up to 6 or 8 percent of the employee s eligible contributions based upon years of service. The Company contributed approximately $11 million, $10 million and $9 million to these plans for the years ended December 31, 2005, 2004 and 2003, respectively, to match eligible contributions by employees.

The Company provides a charitable award benefit to Directors who were elected to serve on the Board of Directors prior to February 2003 and served for at least two years. Upon the death of a Director who qualifies for this benefit, the Company will donate $1 million to one or more educational institutions of higher learning or other charitable organizations, which may include private foundations, nominated by the Director. At December 31, 2005, a $10 million liability has been accrued for these benefits and is included in Other Liabilities and Deferred Credits on the Company s Consolidated Balance Sheet.

The following tables set forth the pension and postretirement amounts recognized in the Consolidated Balance Sheet.

	Pension Benefits		Postretirement Benefits	
Year Ended December 31,	**2005**	**2004**	**2005**	**2004**
	(In Millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$250	$222	$ 36	$ 46
Service cost	12	11		
Interest cost	14	13	2	2
Plan amendment		1		(3)
Actuarial loss	40	15	2	(6)
Currency exchange	1	2		
Participant contributions			2	2
Benefits paid	(21)	(14)	(5)	(5)

Benefit obligation at end of year	296	250	37	36
Change in plan assets				
Fair value of plan assets at beginning of year	214	180		
Actual return on plan assets	13	23		
Currency exchange	1	2		
Employer contribution	46	23	3	3
Participant contributions			2	2
Benefits paid	(21)	(14)	(5)	(5)
Fair value of plan assets at end of year	253	214		
Funded status	(43)	(36)	(37)	(36)
Unrecognized net actuarial loss	87	51	17	17
Unrecognized prior service cost (benefit)	3	3	(7)	(8)
Net prepaid (accrued) benefit cost	$ 47	$ 18	$(27)	$(27)

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

The following table summarizes the projected benefit obligation, accumulated benefit obligation, fair value of plan assets, minimum pension liability and related consolidated balance sheet amounts for the Company s pension plans as of the measurement date.

	U.S.		Canada	
December 31,	**2005**	**2004**	**2005**	**2004**
		(In Millions)		
Benefit obligation	$267	$225	$ 29	$ 25
Accumulated benefit obligation	207	179	26	23
Fair value of plan assets	222	187	31	27
Accrued benefit liability	4		1	1
Prepaid benefit cost	$ 46	$ 15	$ 4	$ 4
Minimum pension liability	$ 2	$	$	$
Accumulated other comprehensive loss	$ 2	$	$	$

The Company expects to contribute $12 million to its pension plans in 2006.

The following table summarizes pension and postretirement benefit expense for the three years ended December 31, 2005.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
			(In Millions)			
Benefit cost for the plans includes the following components						
Service cost	$ 12	$ 11	$ 9	$	$	$
Interest cost	14	13	13	2	2	3
Expected return on plan assets	(14)	(13)	(13)			
Recognized net actuarial loss	5	5	4	1	1	
Net benefit cost	$ 17	$ 16	$ 13	$ 3	$ 3	$ 3

Assumptions used to determine net benefit obligations follow.

	Pension Benefits			Postretirement Benefits		
December 31,	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**

Weighted average assumptions						
Discount rate	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%
Rate of compensation increase	4.50%	4.50%	4.50%			

Assumptions used to determine net benefit cost follow.

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Weighted average assumptions						
Discount rate	5.75%	6.00%	6.75%	5.75%	6.00%	6.75%
Expected return on plan assets	7.50	7.50	8.00			
Rate of compensation increase	4.50%	4.50%	4.50%			

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

The following table summarizes the future expected benefit payments to be paid from the pension and postretirement plans.

Year Ended	Pension Payments	Postretirement Payments(1)
	(In Millions)	
2006	$ 19	$ 3
2007	21	3
2008	23	3
2009	23	3
2010	26	3
2011-2015	$166	$ 14

(1) Includes a reduction each year after 2006 for an expected subsidy related to the Medicare Prescription Drug Improvement and Modernization Act of 2003.

The following table provides the target and actual asset allocations for the Company s pension plans as of December 31.

	U.S.			Canada		
Asset Category	Target	2005	2004	Target	2005	2004
Equity	65%	64%	67%	58%	63%	62%
Fixed income	35	35	33	31	27	27
Other		1		11	10	11
Total	100%	100%	100%	100%	100%	100%

The primary investment objective is to ensure, over the long-term life of the pension plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries. In meeting this objective, the pension plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk while maintaining asset allocations within 5 percent of the target allocation shown above.

The Company bases its assumed discount rate on the annualized Moody s Aa bond rating as an approximation of the yield curve of a portfolio of high-quality zero coupon bonds. Since this index does not vary by duration, the Company compares it to an alternate discount rate calculated by discounting plan cash flows using a yield curve derived from over 300 noncallable bonds rated Aa or better. For the year ended December 31, 2005, the discount rates calculated using each methodology were not significantly different.

To develop the expected long-term rate of return on assets assumption, the Company considered the current level of expected returns on risk-free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. Since the Company s investment policy is to actively manage certain asset classes where the potential exists to outperform the broader market, the expected returns for those asset classes were adjusted to reflect the expected additional returns. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. This process resulted in the selection of the 7.5 percent assumption.

A 9 percent annual rate of increase in the per capita cost of pre-age 65 covered health care benefits was assumed for 2006. The rate is assumed to decrease gradually to 5 percent for 2010 and remain at that level thereafter. An 11 percent annual rate of increase in the per capita cost of post-age 65 covered health care benefits was assumed for 2006 to gradually decrease to 5 percent for 2012 and remain at that level thereafter. Assumed health care cost trends have a significant effect on the amounts reported for the postretirement medical and dental care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	1-Percentage Point Increase	**1-Percentage Point Decrease**
	(In Thousands)	
Effect on total service and interest cost	$ 144	$ (126)
Effect on postretirement benefit obligation	$2,845	$(2,493)

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

14. Commitments and Contingent Liabilities

Transportation Demand Charges

The Company has entered into contracts which provide firm transportation capacity rights on pipeline systems. The remaining terms on these contracts range from 1 to 18 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. The Company paid $181 million, $193 million and $179 million of demand charges for the years ended December 31, 2005, 2004 and 2003, respectively. All transportation costs including demand charges are included in transportation expense in the Consolidated Statement of Income.

Future transportation demand charge commitments at December 31, 2005 follow.

	(In Millions)
2006	$152
2007	118
2008	95
2009	75
2010	58
Thereafter	299
Total	$797

Lease Obligations and Other Commitments

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $32 million, $35 million and $38 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2005 follow.

	(In Millions)
2006	$ 36
2007	33
2008	34
2009	33
2010	35
Thereafter	136
Total	$307

The Company s drilling rig commitments at December 31, 2005 follow.

	(In Millions)
2006	$ 65
2007	36
2008	20

2009	13
2010	5
Thereafter	
Total	$139

Legal Proceedings

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

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

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 analyzed the potential impact of the Amoco ruling and determined that, if upheld, the decision will have a negative impact on 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.

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 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 court certified the plaintiff classes of royalty and overriding royalty interest owners, and trial by jury commenced on October 10, 2005, during which plaintiffs sought monetary damages of up to $42 million in principal, plus $311 million in interest, and unspecified punitive damages and attorney s fees. The Company presented substantial defenses to these claims. In a separate action, the Company and El Paso Natural Gas Company asserted contractual claims for indemnity against each other. On November 9, 2005, the parties counsel entered into a preliminary agreement to settle this lawsuit for $66 million, plus interest on this amount commencing January 20, 2006, as provided in the settlement agreement. On January 20, 2006, the Court preliminarily approved the settlement and scheduled a fairness hearing to determine the fairness to class members of the proposed settlement, which is scheduled to commence in May 2006. The Company and El Paso Natural Gas Company have reached a preliminary agreement to settle the contractual indemnity claims against each other. The settlement of the indemnity claims is subject to final court approval of the class action settlement. Upon final court approval of the class action settlement, the Company s contribution to the settlement will be approximately $36 million, plus interest from January 20, 2006, as provided in the settlement agreement. The Company has established a reserve to provide for this potential liability based upon management s evaluation of this matter.

The Company and its directors have been named defendants in a lawsuit styled *Jeffrey Halpern, Derivatively on Behalf of Burlington Resources Inc., Plaintiff, vs. Bobby S. Shackouls, et al., and Burlington Resources Inc. a Delaware Corporation, Nominal Defendant,* Cause No. 2005-79250, filed on December 15, 2005, in the 215th Judicial District Court of Harris County, Texas (Halpern case) and also named as defendants in a lawsuit styled *Charles Conrardy, On Behalf of Himself and All Others Similarly Situated, Plaintiff, vs. Burlington Resources Inc., et al.*, Cause No. 2005-79267, filed on December 16, 2005, in the 165th Judicial District Court of Harris County, Texas (Conrardy case). Both lawsuits allege that Company s board of directors breached its fiduciary duties in approving the proposed merger announced on December 12, 2005, between the Company and ConocoPhillips. The Halpern case is a stockholder derivative action purportedly filed on behalf of the Company against the Company s board of directors, and contains claims for abuse of control, breach of the duty of candor, gross mismanagement, waste and unjust enrichment, and breach of fiduciary duty. The Conrardy case is a purported stockholder class action lawsuit against the Company and the Company s board of directors, and contains a claim for breach of fiduciary duty. Both petitions allege, among other things, that the Company s board of directors engaged in self dealing by approving a proposed merger that allegedly advances the Company s board of directors personal interests at the expense of the Company s stockholders, thus causing the Company s stockholders to receive an unfair price for their shares of the Company s common stock. Both petitions seek, among other things, an injunction preventing the completion of the merger, rescission if the merger is consummated, attorneys fees and expenses associated with the lawsuit, and

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

any other further equitable relief as the courts may deem just and proper. The Company believes these actions are without merit and intends to defend them vigorously. The Company has not established a reserve for these matters.

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.

At December 31, 2005, the Company s Consolidated Balance Sheet included reserves for legal proceedings of $137 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, the Company believes 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.

15. Supplemental Cash Flow Information

The following is additional information concerning supplemental disclosures of cash payments.

Year Ended December 31,	**2005**	**2004**	**2003**
		(In Millions)	
Interest paid net of capitalized interest(1)	$273	$275	$251

Income taxes paid net	$794	$274	$171

(1) The Company recorded capitalized interest of $1 million and $25 million for the years ended December 31, 2005 and 2003, respectively. The Company had no capitalized interest for the year ended December 31, 2004.

At December 31, 2005 and 2004, capital expenditures included in the Accounts Payable balance on the Company s Consolidated Balance Sheet were $555 million and $333 million, respectively.

16. Impairment of Oil and Gas Properties

During the year ended December 31, 2005, the Company recorded an impairment charge of $50 million for a downward reserve adjustment primarily related to its onshore China properties. During the year ended December 31, 2004, the Company recorded an impairment charge of $90 million related to unproved properties in Canada. During the year ended December 31, 2003, the Company recorded charges of $63 million related to the impairment of oil and gas properties due to performance-related downward reserve adjustments associated with certain properties primarily in Canada.

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

17. Segment and Geographic Information

The Company s reportable segments are U.S., Canada and International. The Company is engaged principally in the exploration, development, production and marketing of natural gas, crude oil and NGLs. The Company s reportable segments are managed separately based on their geographic location. The accounting policies for the segments are the same as those described in Note 1 of Notes to Consolidated Financial Statements. There were no intersegment sales in 2005, 2004 or 2003.

The following tables present information about reported segment operations.

	North America			
Year Ended December 31, 2005	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$3,891	$2,707	$ 989	$ 7,587
Depreciation, depletion and amortization	434	651	202	1,287
Impairment of oil and gas properties			50	50
Income before income taxes	2,766	1,412	471	4,649
Properties net	4,845	6,188	1,326	12,359
Goodwill		1,089		1,089
Capital expenditures	$1,281	$1,217	$ 175	$ 2,673

	North America			
Year Ended December 31, 2004	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,710	$2,100	$ 808	$ 5,618
Depreciation, depletion and amortization	363	535	214	1,112
Impairment of oil and gas properties		90		90
Income before income taxes	1,612	891	341	2,844
Properties net	3,984	5,541	1,417	10,942
Goodwill		1,054		1,054
Capital expenditures	$ 719	$ 842	$ 166	$ 1,727

	North America			
Year Ended December 31, 2003	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,111	$1,925	$ 275	$ 4,311

Depreciation, depletion and amortization	307	493	102	902
Impairment of oil and gas properties	5	58		63
Income before income taxes and cumulative effect of change in accounting principle	1,124	869	39	2,032
Properties net	3,608	5,102	1,505	10,215
Goodwill		982		982
Capital expenditures	$ 545	$ 715	$ 505	$ 1,765

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

The following is a reconciliation of segment income before income taxes and cumulative effect of change in accounting principle to consolidated income before income taxes and cumulative effect of change in accounting principle. For segment reporting purposes, corporate expenses, total interest expense and other expense (income) net have been excluded from segment operations.

Year Ended December 31,	2005	2004	2003
		(In Millions)	
Income before income taxes and cumulative effect of change in accounting principle for reportable segments	$4,649	$2,844	$2,032
Corporate expenses	282	239	189
Interest expense	281	282	260
Other expense net	38	19	13
Consolidated income before income taxes and cumulative effect of change in accounting principle	$4,048	$2,304	$1,570

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

Year Ended December 31,	2005	2004	2003
		(In Millions)	
Total capital expenditures for reportable segments	$2,673	$1,727	$1,765
Corporate administrative capital expenditures	14	20	23
Consolidated capital expenditures	$2,687	$1,747	$1,788

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

December 31,	2005	2004	2003
		(In Millions)	
Properties net for reportable segments	$12,359	$10,942	$10,215
Corporate properties net	79	91	96
Consolidated properties net	$12,438	$11,033	$10,311

18. Taxes Other Than Income Taxes

Taxes other than income taxes are as follow.

Year Ended December 31,	2005	2004	2003
		(In Millions)	
Severance taxes	$278	$204	$141
Ad valorem taxes	56	36	30
Payroll taxes and other	21	20	16
Taxes other than income taxes	$355	$260	$187

19. Other Matters

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. The Company adopted SFAS No. 154 on 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 March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143* (Interpretation). This Interpretation clarifies that the term *conditional asset retirement obligation* as

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

used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This Interpretation is effective for the Company s year ended December 31, 2005. The adoption of this Interpretation did not impact the Company s consolidated financial position or results of operations.

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 December 15, 2005. The Company adopted 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 will result in the Company recording an expense of approximately $10 million in 2006.

In September 2005, the FASB issued EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue). This Issue addresses the accounting for purchase and sales arrangements with the same party and is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first interim or annual reporting period beginning after March 15, 2006. The adoption of this Issue is not expected to have a material impact on the Company s consolidated financial position or results of operations.

Subsequent Event

In January 2006, the Company acquired oil and gas properties in the Bossier trend of east Texas for approximately $381 million, net of purchase price adjustments. The acquisition was funded in part with the remaining proceeds of $64 million from the Units sale.

January 16, 2006

Burlington Resources Inc.
717 Texas Avenue, Suite 2100
Houston, TX 77002

Re: Proved Reserves as of December 31, 2005

Gentlemen:

At your request, we reviewed the estimates of domestic and international proved reserves of oil, condensate, natural gas, and natural gas liquids (NGLs) that Burlington Resources Inc. (BR) attributes to its net interests in oil and gas properties as of December 31, 2005. BR s estimates of proved reserves shown below are in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a).

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, Condensate, and NGLs, Million Barrels	435.9	152.9	588.8
Gas, Billions of Cubic Feet	4,150.2	1,818.6	5,968.8

Based on our investigations and subject to the limitations described hereinafter, it is our judgment that (1) BR has an effective system for gathering data and documenting information required to estimate its proved reserves; (2) in making its estimates, BR uses appropriate engineering, geologic, and evaluation principles and techniques that are in accordance with practices generally accepted in the petroleum industry; and (3) the results of the estimates prepared by BR that we reviewed are, in the aggregate, reasonable.

Gas volumes were estimated at the appropriate pressure base and temperature base established for each well or field by the applicable sales contract or regulatory body. Total gas reserves were obtained by summing the reserves for all the individual properties and are therefore stated at a mixed pressure base.

In conducting our audit, we reviewed BR s estimates of wet gas volumes prior to adjustment for impurities, shrinkage, and NGL recovery. We reviewed these wet gas volumes, along with the methods employed by BR, to convert these volumes to sales gas volumes and NGLs. In our judgment, the conversion methods used by BR to adjust the wet volumes to account for impurities, fuel use, shrinkage, and NGL recovery are appropriate and reasonable.

We reviewed approximately 82 percent of BR s estimated proved reserves forecasts and either accepted its forecast or revised them as needed. We selected the sampling of properties for independent estimates and review. In general, those properties with the largest reserves were selected for review. We investigated the pertinent available engineering, geological, and accounting information to satisfy ourselves that BR s reserve estimates are, in the aggregate, reasonable. In making our reserve estimates and comparing them with BR s estimates, we used product prices and expenses provided by BR. The prices used were represented by BR as the actual prices received for oil, condensate, natural gas, and NGLs on December 31, 2005, and are in accordance with Securities and Exchange Commission guidelines.

Burlington Resources Inc. January 16, 2006

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These reserve estimates are based primarily on decline curve analysis, material balance calculations, volumetric calculations, analogies, or combinations of these methods. Reserve estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves were produced.

In conducting these evaluations, we relied upon production histories, accounting data, and other financial, operating, engineering, geological and geophysical data supplied by BR. To a lesser extent, data existing in the files of Miller and Lents, Ltd. and data obtained from commercial services were used. We also relied, without independent verification, upon BR s representation of its ownership interests for each property.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in Burlington Resources Inc. or any affiliated company. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity. Production of this report was supervised by an officer of the firm who is a professionally qualified and licensed Professional Engineer in the State of Texas with more than 20 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those employed in this study may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those reviewed for this report.

Very truly yours,

MILLER AND LENTS, LTD.

Robert J. Oberst
Senior Vice President

R.W. Frazier
Senior Vice President

RJO/sg

Ref.: 1408.15626

January 11, 2006

Burlington Resources Inc.
Ste. 2100, 717 Texas Avenue
Houston, TX 77002-2712

Re: Unqualified Audit Opinion of Burlington Resources Incorporated Canadian Proved Reserves, as of December 31, 2005

Gentlemen:

At your request, we have examined the proved oil, natural gas liquids, and natural gas reserves estimates of Burlington Resources Incorporated (Burlington) Canadian properties, as of December 31, 2005. Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

Table 1 presents Burlington s estimates of proved oil, natural gas liquids and natural gas reserves, which are in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a).

Table 1
Summary of Burlington Resources Incorporated Canadian Proved Reserves Estimates
Using Net Marketable Gas Volumes

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil, MMbbl	13.3	2.9	16.2
Natural Gas, Bcf	1,956	583	2,539
Natural Gas Liquids, MMbbl	45.1	12.6	57.7

70

The volumes of natural gas liquids are comprised of ethane, propane, butanes, condensate and pentanes plus. All volumes are reported net, after royalties.

We are independent with respect to Burlington, as provided in the Standard Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our audit does not constitute a complete reserves study of the oil and gas properties of Burlington. In the conduct of our audit, we did not independently verify the accuracy and completeness of information and data furnished by Burlington with respect to ownership interests, oil and gas production, historical costs of operation and development, product prices, agreements relating to current and future operations and sales of production, etc. Burlington s Canadian reserves assignments were audited directly by a Citrix link into the PEEP reserves database, and by reviewing available public data to determine if those assignments were reasonable. If in the course of our examination something came to our attention that brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

The proved developed producing reserves and production forecasts were estimated by production decline extrapolations, water-oil ratio trends, material balance, or by volumetric calculations. For some properties with insufficient performance history to establish trends, we estimated future production by analogy with other properties with similar characteristics. The past performance trends of many properties were influenced by production curtailments, workovers, waterfloods, and/or infill drilling. Actual future production may require that our estimated trends be significantly altered.

The estimated proved undeveloped reserves require significant capital expenditures for items such as the drilling, completion and tie-in of wells. The proved undeveloped reserves estimates for infill wells are based on analogies to similar infill wells in the same field and/or the production histories of offset wells in the same field.

Reserve estimates from volumetric calculations and from analogies are often less certain than reserves estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The reserves estimates presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgements based on accepted standards of professional investigation, but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical and engineering information. Government policies and market conditions different from those employed in this review may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those estimated in this audit.

In our opinion, the estimates of Burlington s proved reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

This letter is solely for the information of Burlington Resources Inc. and for the information and assistance of its independent public accountants in connection with their review of, and report upon, the financial statements of Burlington Resources Inc. This letter should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law.

Our working papers are available for review upon request. If you have any questions regarding the above, or if we may be of further assistance, please call us.

Sincerely,

Robert N. Johnson, P.Eng.
Manager, Engineering and
Corporate Secretary

Ken H. Crowther, P.Eng
President

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Supplemental Oil and Gas Disclosures Unaudited

The supplemental data presented herein reflects information for all of the Company s oil and gas producing activities.

Costs incurred for oil and gas property acquisition, exploration and development activities follow.

	North America			
Year Ended December 31, 2005	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Property acquisition				
Proved	$ 294	$ 34	$	$ 328
Unproved	56	47		103
Exploration	133	199	32	364
Development				
Proved developed	570	722	60	1,352
Proved undeveloped	225	175	67	467
Costs incurred before estimated asset retirement obligations	1,278	1,177	159	2,614
Estimated asset retirement obligations incurred(1)	50	53	20	123
Total costs incurred	$1,328	$1,230	$179	$2,737

	North America			
Year Ended December 31, 2004	**U.S.**	**Canada**	**International**	**Total**
	(In Millions)			
Property acquisition				
Proved	$ 81	$ 4	$	$ 85
Unproved	32	33	2	67
Exploration	55	126	38	219
Development				
Proved developed	473	526	36	1,035
Proved undeveloped	71	113	54	238
Costs incurred before estimated asset retirement obligations	712	802	130	1,644
Estimated asset retirement obligations incurred(1)	18	(5)	(2)	11
Total costs incurred	$730	$797	$128	$1,655

Year Ended December 31, 2003	North America U.S.	North America Canada	International	Total
			(In Millions)	
Property acquisition				
Proved	$110	$ 19	$ 99	$ 228
Unproved	9	79	2	90
Exploration	43	135	33	211
Development				
Proved developed	246	375	36	657
Proved undeveloped	132	71	196	399
Costs incurred before estimated asset retirement obligations	540	679	366	1,585
Estimated asset retirement obligations incurred(1)	6	26	52	84
Total costs incurred	$546	$705	$418	$1,669

(1) Amounts are shown net of current year estimated cash flow revisions.

The Company estimates that it will spend capital of approximately $1,015 million, $870 million and $621 million in 2006, 2007 and 2008, respectively, for the development of its proved undeveloped reserves.

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Results of operations for natural gas, NGLs and crude oil producing activities, which exclude processing and other activities, corporate general and administrative expenses and straight-line depreciation expense, were as follow. There were no intersegment sales in 2005, 2004 and 2003.

	North America			
Year Ended December 31, 2005	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$3,870	$2,686	$987	$7,543
Production costs	539	215	114	868
Exploration costs	75	186	32	293
Operating expenses	316	243	120	679
Depreciation, depletion and amortization	417	621	199	1,237
Impairment of oil and gas properties			50	50
Income tax provision	936	544	155	1,635
Results of operations for oil and gas producing activities	$1,587	$ 877	$317	$2,781

	North America			
Year Ended December 31, 2004	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Revenues	$2,690	$2,087	$807	$5,584
Production costs	407	200	97	704
Exploration costs	37	154	67	258
Operating expenses	284	221	90	595
Depreciation, depletion and amortization	346	512	212	1,070
Impairment of oil and gas properties		90		90
Income tax provision	554	315	201	1,070
Results of operations for oil and gas producing activities	$1,062	$ 595	$140	$1,797

	North America			
Year Ended December 31, 2003	**U.S.**	**Canada**	**International**	**Total**

	(In Millions)			
Revenues	$2,089	$1,911	$275	$4,275
Production costs	317	173	46	536
Exploration costs	100	121	31	252
Operating expenses	270	206	58	534
Depreciation, depletion and amortization	288	461	100	849
Impairment of oil and gas properties	5	58		63
Income tax provision	345	201	10	556
Results of operations for oil and gas producing activities	$ 764	$ 691	$ 30	$1,485

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BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

The following table reflects estimated quantities of proved natural gas, NGLs and crude oil reserves. These reserves have been estimated by the Company s petroleum engineers in accordance with the Securities and Exchange Commission s Regulations. The Company considers such estimates to be reasonable, however, due to inherent uncertainties, estimates of underground reserves are imprecise and subject to change over time as additional information becomes available.

Miller and Lents, Ltd. and Sproule Associates Limited, independent oil and gas consultants, have reviewed the estimates of proved reserves of natural gas, NGLs and crude oil that BR attributed to its net interests in oil and gas properties as of December 31, 2005. Miller and Lents, Ltd. reviewed the reserve estimates for the Company s U.S. and International interests and Sproule Associates Limited reviewed the Company s interests in Canada. Based on their review of more than 80 percent of the Company s reserve estimates, it is their judgment that the estimates are reasonable in the aggregate.

	Crude Oil (MMBbls)			
	North America			
	U.S.	Canada	International	Worldwide
Proved Developed and Undeveloped Reserves				
December 31, 2002	187.2	14.4	86.3	287.9
Revisions of previous estimates	(4.9)	0.4	1.7	(2.8)
Extensions, discoveries and other additions	11.0	2.8		13.8
Production	(10.7)	(1.9)	(4.4)	(17.0)
Purchase of reserves in place	0.5	0.1		0.6
Sales of reserves in place	(0.3)	(0.1)		(0.4)
December 31, 2003	182.8	15.7	83.6	282.1
Revisions of previous estimates	13.7	(0.7)	6.0	19.0
Extensions, discoveries and other additions	18.9	4.9	1.2	25.0
Production	(13.7)	(2.0)	(15.5)	(31.2)
Purchase of reserves in place	2.8			2.8
Sales of reserves in place				
December 31, 2004	204.5	17.9	75.3	297.7
Revisions of previous estimates	(7.2)	(1.5)	(3.5)	(12.2)
Extensions, discoveries and other additions	8.7	2.0	14.2	24.9
Production	(18.0)	(2.2)	(13.8)	(34.0)
Purchase of reserves in place	0.7			0.7
Sales of reserves in place	(2.9)			(2.9)
December 31, 2005	185.8	16.2	72.2	274.2
Proved Developed Reserves				
December 31, 2002	155.2	12.9	12.9	181.0
December 31, 2003	176.5	13.1	50.8	240.4
December 31, 2004	185.8	13.6	48.5	247.9
December 31, 2005	172.0	13.3	42.5	227.8

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

NGLs (MMBbls)			Natural Gas (BCF)				
North America			North America				Total Equivalent (BCFE)
U.S.	Canada	Worldwide	U.S.	Canada	International	Worldwide	
240.4	59.8	300.2	4,753	2,296	841	7,890	11,418
19.8	(0.7)	19.1	(88)	(57)	(45)	(190)	(91)
22.9	12.0	34.9	425	427	54	906	1,198
(13.6)	(10.0)	(23.6)	(315)	(317)	(61)	(693)	(937)
0.6	0.3	0.9	131	9	79	219	228
(0.5)	(0.1)	(0.6)	(54)	(4)		(58)	(64)
269.6	61.3	330.9	4,852	2,354	868	8,074	11,752
4.0	(8.5)	(4.5)	40	(77)	2	(35)	52
19.7	9.8	29.5	475	352	18	845	1,172
(15.3)	(8.6)	(23.9)	(333)	(300)	(68)	(701)	(1,031)
0.5	0.1	0.6	43	4		47	67
(0.1)		(0.1)	(1)	(3)		(4)	(5)
278.4	54.1	332.5	5,076	2,330	820	8,226	12,007
39.4	1.0	40.4	(88)	34	(74)	(128)	42
27.8	11.3	39.1	522	465	3	990	1,374
(15.5)	(8.8)	(24.3)	(347)	(293)	(55)	(695)	(1,045)
1.8	0.2	2.0	120	6		126	142
(1.1)	(0.1)	(1.2)	(8)	(3)		(11)	(36)
330.8	57.7	388.5	5,275	2,539	694	8,508	12,484
179.2	53.1	232.3	3,617	1,836	263	5,716	8,196
188.6	50.8	239.4	3,715	1,837	322	5,874	8,753
193.1	44.6	237.7	3,745	1,821	435	6,001	8,915
221.4	45.1	266.5	3,752	1,956	398	6,106	9,072

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

A summary of the standardized measure of discounted future net cash flows relating to proved natural gas, NGLs and crude oil reserves is shown below. Future net cash flows are computed using year end commodity prices, costs and statutory tax rates (adjusted for tax credits and other items) that relate to the Company s existing proved natural gas, NGLs and crude oil reserves.

	North America			
2005	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Future cash inflows	$56,061	$25,560	$8,741	$90,362
Less related future				
Production costs(1)	11,590	4,156	1,099	16,845
Development costs	2,367	1,710	502	4,579
Income taxes	14,703	6,016	2,881	23,600
Future net cash flows	27,401	13,678	4,259	45,338
10% annual discount for estimated timing of cash flows	14,849	5,542	1,390	21,781
Standardized measure of discounted future net cash flows	$12,552	$ 8,136	$2,869	$23,557

	North America			
2004	**U.S.**	**Canada**	**International**	**Total**
		(In Millions)		
Future cash inflows	$38,750	$14,787	$5,544	$59,081
Less related future				
Production costs(1)	8,070	2,705	1,063	11,838
Development costs	1,658	1,047	429	3,134
Income taxes	9,927	3,208	1,445	14,580
Future net cash flows	19,095	7,827	2,607	29,529
10% annual discount for estimated timing of cash flows	10,575	2,948	788	14,311
Standardized measure of discounted future net cash flows	$ 8,520	$ 4,879	$1,819	$15,218

2003	North America U.S.	North America Canada	International	Total
		(In Millions)		
Future cash inflows	$34,868	$14,689	$5,357	$54,914
Less related future				
Production costs(1)	6,551	2,219	1,342	10,112
Development costs	888	717	424	2,029
Income taxes	9,351	3,416	1,102	13,869
Future net cash flows	18,078	8,337	2,489	28,904
10% annual discount for estimated timing of cash flows	9,937	3,028	762	13,727
Standardized measure of discounted future net cash flows	$ 8,141	$ 5,309	$1,727	$15,177

(1) Include lease operating expenses, severance taxes, ad valorem taxes and estimated asset retirement costs, net of estimated salvage recoveries.

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved natural gas, NGLs and crude oil reserves follows.

	2005	2004	2003
		(In Millions)	
January 1,	$15,218	$15,177	$10,414
Revisions of previous estimates			
Changes in prices and costs	11,505	606	6,050
Changes in quantities	168	173	(111)
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	3,555	1,978	2,119
Purchases of reserves in place	375	126	416
Sales of reserves in place	(70)	(10)	(86)
Accretion of discount	2,209	2,165	1,472
Sales, net of production costs	(6,675)	(4,880)	(3,739)
Net change in income taxes	(4,617)	(401)	(2,163)
Changes in rate of production and other	1,889	284	805
Net change	8,339	41	4,763
December 31,	$23,557	$15,218	$15,177

Quarterly Financial Data Unaudited

	2005				2004			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In Millions, Except per Share Amounts)							
Revenues	$2,372	$1,953	$1,686	$1,576	$1,558	$1,419	$1,333	$1,308
Income before income taxes(a)	1,385	1,119	805	739	588	629	540	547
Net income(b)	954	748	537	471	400	394	379	354
Basic earnings per common share(a)(b)	2.54	1.98	1.41	1.22	1.03	1.00	0.96	0.90
Diluted earnings per common(a)(b)	2.52	1.96	1.40	1.21	1.02	1.00	0.96	0.89
Cash dividends declared per common share	0.10	0.10	0.09	0.08	0.08	0.09	0.07	0.08
Common stock price range								

High	87.03	81.98	57.18	53.32	46.41	41.24	37.49	31.98
Low	$64.02	$55.57	$44.72	$40.40	$39.19	$34.92	$31.23	$26.33

(a) During the third quarter of 2005, the Company recorded 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 (Units) held by the Company. During the fourth quarter of 2005, the Company also recorded a pretax gain of $123 million ($76 million after tax or $0.20 per diluted share) related to the sale of 8,600,000 Units held by the Company. During the fourth quarters of 2005 and 2004, the Company recognized non-cash, pretax charges of $50 million ($34 million after tax or $0.09 per diluted share) and $90 million ($59 million after tax or $0.15 per diluted share), respectively, related to the impairment of oil and gas properties.

(b) The fourth quarter of 2004 includes a U.S. income tax expense of $26 million ($0.07 per diluted share) related to the planned repatriation of $500 million under the one-time provisions of the American Jobs Creation Act of 2004.

ITEM NINE

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM NINE A

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. See page 38 for Management Report on Internal Control over Financial Reporting.

ITEM NINE B

OTHER INFORMATION

None

PART III

ITEMS TEN AND ELEVEN

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT AND EXECUTIVE COMPENSATION

Information required by Part III, items ten and eleven, will either be included in the Company s definitive proxy statement (the Proxy Statement) filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended. Certain information with respect to the executive officers of the Company is set forth under the caption Executive Officers of the Registrant in Part I of this report.

The Company has adopted a Code of Business Conduct and Ethics (Code of Conduct) that applies to directors, officers and employees, including the principal executive officer, principal financial officer and principal accounting officer or controller and has posted such code on its Web site at www.br-inc.com. Changes to and waivers granted with respect to the Company s Code of Conduct related to the above named officers, other executive officers and Directors required to be disclosed pursuant to the applicable rules and regulations will also be posted on the Company s Web site. The Company s Code of Conduct, as well as its

Corporate Governance Guidelines and its Audit, Compensation and Governance and Nominating Committee charters are available on its Web site and in print to any shareholder who requests them.

ITEM TWELVE

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by Part III, item twelve, will either be included in the Proxy Statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

EQUITY COMPENSATION PLAN INFORMATION

At December 31, 2005

Plan Category	**Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights(2) (a)**	**Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights(2) (b)**	**Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) (c)**
Equity compensation plans approved by security holders	3,428,730	$30.68	9,263,370
Equity compensation plan not approved by security holders(1)	826,538	21.34	8,120,843
Total	4,255,268	$28.87	17,384,213

(1) See Note 12 of Notes to Consolidated Financial Statements for a description of the Company s 1997 Employee Stock Incentive Plan, which is the only compensation plan in effect that was adopted without the approval of the Company s stockholders.

ITEM THIRTEEN

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by Part III, item thirteen, will either be included in the Proxy Statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

ITEM FOURTEEN

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Part III, item fourteen, will either be included in the Proxy Statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

PART IV

ITEM FIFTEEN

EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

SIGNATURES REQUIRED FOR FORM 10-K

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Burlington Resources Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BURLINGTON RESOURCES INC.

By /s/ BOBBY S. SHACKOULS

Bobby S. Shackouls
Chairman of the Board, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Burlington Resources Inc. and in the capacities and on the dates indicated.

By /s/ BOBBY S. SHACKOULS Bobby S. Shackouls	Chairman of the Board, President and Chief Executive Officer	February 28, 2006
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Director, Executive Vice President Finance and Corporate Development	February 28, 2006
/s/ JOSEPH P. MCCOY Joseph P. McCoy	Senior Vice President and Chief Financial Officer	February 28, 2006
/s/ DANE E. WHITEHEAD Dane E. Whitehead	Vice President, Controller and Chief Accounting Officer	February 28, 2006
/s/ BARBARA T. ALEXANDER Barbara T. Alexander	Director	February 28, 2006
/s/ REUBEN V. ANDERSON Reuben V. Anderson	Director	February 28, 2006
/s/ LAIRD I. GRANT Laird I. Grant	Director	February 28, 2006
/s/ ROBERT J. HARDING Robert J. Harding	Director	February 28, 2006
/s/ JOHN T. LAMACCHIA	Director	February 28, 2006

John T. LaMacchia		
/s/ RANDY L. LIMBACHER	Director	February 28, 2006
Randy L. Limbacher		
/s/ JAMES F. MCDONALD	Director	February 28, 2006
James F. McDonald		
/s/ KENNETH W. ORCE	Director	February 28, 2006
Kenneth W. Orce		
/s/ DONALD M. ROBERTS	Director	February 28, 2006
Donald M. Roberts		
/s/ JAMES A. RUNDE	Director	February 28, 2006
James A. Runde		
/s/ JOHN F. SCHWARZ	Director	February 28, 2006
John F. Schwarz		
/s/ WALTER SCOTT, JR.	Director	February 28, 2006
Walter Scott, Jr.		
/s/ WILLIAM E. WADE, JR.	Director	February 28, 2006
William E. Wade, Jr.		

BURLINGTON RESOURCES INC.
AMENDED EXHIBIT INDEX

The following exhibits are filed as part of this report.

Exhibit Number	Description	
2.1	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (Exhibit 2.1 to Form 8-K filed December 14, 2005)	*
3.1	Certificate of Incorporation of Burlington Resources Inc. as amended April 21,2004 (Exhibit 3.1 to Form 10-Q, filed May 7, 2004)	*
3.2	By-Laws of Burlington Resources Inc. amended as of March 1, 2003 (Exhibit 3.2 to Form 10-K, filed March 12, 2003)	*
4.1	Form of Shareholder Rights Agreement dated as of December 16, 1998, between Burlington Resources Inc. and EquiServe Trust Company, N.A. (the current Rights Agent) which includes, as Exhibit A thereto, the form of Certificate of Designation specifying terms of the Series A Junior Participating Preferred Stock and, as Exhibit B thereto, the form of Rights Certificate (Exhibit 1 to Form 8-A, filed December 1998)	*
4.2	Indenture, dated as of June 15, 1990, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.2 to Form 8, filed February 1992)	*
4.3	Indenture, dated as of October 1, 1991, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.3 to Form 8, filed February 1992)	*
4.4	Indenture, dated as of April 1, 1992, between Burlington Resources Inc. and Citibank, N.A. (as Trustee), including Form of Debt Securities (Exhibit 4.4 to Form 8, filed March 1993)	*
4.5	Indenture, dated as of June 15, 1992, between The Louisiana Land and Exploration Company (LL&E) and Texas Commerce Bank National Association (as Trustee) (Exhibit 4.1 to LL&E s Form S-3, as amended, filed November 1993)	*
4.6	Indenture, dated as of February 12, 2001, between Burlington Resources Finance Company and Citibank, N.A. (as Trustee), including form of Debt Securities (Exhibit 4.2 to Form S-4, filed April 2002)	*
4.7	Guarantee Agreement, dated as of February 12, 2001, of Burlington Resources Inc. with Respect to Senior Debt Securities of Burlington Resources Finance Company (Exhibit 4.5 to Form S-4, filed April 2002)	*

4.8	The Company and its subsidiaries either have filed with the Securities and Exchange Commission or upon request will furnish a copy of any instruments with respect to long-term debt of the Company	*
10.1	Burlington Resources Inc. Incentive Compensation Plan as amended and restated (Exhibit 10.29 to Form 10-Q, filed November 2000)	*
	Amendment to Burlington Resources Inc. Incentive Compensation Plan dated December 2000 (Exhibit 10.2 to Form 10-K, filed February 2001)	*
	Amendment No. 1, dated January 9, 2002, to Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.2 to Form 10-Q, filed April 2002)	*
	Amendment No. 2, dated July 21, 2004, to Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.4 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*
10.2	Burlington Resources Inc. Senior Executive Survivor Benefit Plan dated as of January 1, 1989 (Exhibit 10.11 to Form 8, filed February 1989)	*
10.3	Burlington Resources Inc. Deferred Compensation Plan as amended and restated (Exhibit 10.4 to Form 10-K, filed February 1997)	*
	Amendment No. 1, dated July 21, 2004, to Burlington Resources Inc. Deferred Compensation Plan (Exhibit 10.3 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Deferred Compensation Plan (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*

Exhibit Number	Description	
10.4	Burlington Resources Inc. Supplemental Benefits Plan as amended and restated (Exhibit 10.5 to Form 10-K, filed February 1997)	*
	Amendment No. 4, dated January 1, 1997, to Burlington Resources Inc. Supplemental Benefits Plan (Exhibit 10.5 to Form 10-Q filed August 3, 2004)	*
	Amendment No. 5, dated July 21, 2004, to Burlington Resources Inc. Supplemental Benefits Plan (Exhibit 10.6 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Supplemental Benefits Plan (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*
10.5	Amended and Restated Employment Contract between the Company and Bobby S. Shackouls (Exhibit 10.29 to Form 10-Q, filed August 1999)	*
10.6	Burlington Resources Inc. Compensation Plan for Non-Employee Directors as amended and restated (Exhibit 10.8 to Form 10-K, filed February 1997)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Compensation Plan for Non-Employee Directors (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*
	Amendment No. 1, dated December 19, 2005, to Burlington Resources Inc. Compensation Plan for Non-Employee Directors	
10.7	Amended and Restated Burlington Resources Inc. Executive Change in Control Severance Plan (Exhibit 10.8 to Form 10-K, filed February 2001)	*
10.8	Burlington Resources Inc. Retirement Income Plan for Directors (Exhibit 10.21 to Form 8, filed February 1991)	*
10.9	Burlington Resources Inc. 1991 Director Charitable Award Plan, dated as of January 16, 1991 (Exhibit 10.21 to Form 8, filed February 1991)	*
	Amendment No. 1, dated April 9, 1997, to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.10 to Form 10-K, filed March 12, 2003)	*
	Amendment No. 2, dated January 22, 2003, to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.10 to Form 10-K, filed March 12, 2003)	*

	Amendment No. 3, dated December 2003, to Burlington Resources Inc. 1991 Director Charitable Award Plan (Exhibit 10.9 to Form 10-K, filed February 26, 2004)	*
10.10	Master Separation Agreement and documents related thereto dated January 15, 1992 by and among Burlington Resources Inc., El Paso Natural Gas Company and Meridian Oil Holding Inc., including exhibits (Exhibit 10.24 to Form 8, filed February 1992)	*
10.11	Burlington Resources Inc. 1992 Stock Option Plan for Non-employee Directors (Exhibit 28.1 of Form S-8, No. 33-46518, filed March 1992)	*
10.12	Burlington Resources Inc. Key Executive Retention Plan and Amendments No. 1 and 2 (Exhibit 10.20 to Form 8, filed March 1993)	*
	Amendments No. 3 and 4 to the Burlington Resources Inc. Key Executive Retention Plan (Exhibit 10.17 to Form 10-K, filed February 1994)	*
10.13	Burlington Resources Inc. 1992 Performance Share Unit Plan as amended and restated (Exhibit 10.17 to Form 10-K, filed February 1997)	*
10.14	Burlington Resources Inc. 1993 Stock Incentive Plan (Exhibit 10.22 to Form 10-K, filed February 1994)	*
	Amendment to Burlington Resources Inc. 1993 Stock Incentive Plan dated April 2000 (Exhibit 10.15 to Form 10-K, filed February 2001)	*
	Amendment to Burlington Resources 1993 Stock Incentive Plan dated December 2000 (Exhibit 10.2 to Form 10-K, filed February 2001)	*
	Amendment to Burlington Resources Inc. 1993 Stock Incentive Plan dated December 2003 (Exhibit 10.14 to Form 10-K, filed February 26, 2004)	*
10.15	Burlington Resources Inc. 1994 Restricted Stock Exchange Plan (Exhibit 10.23 to Form 10-K, filed February 1995)	*
	Amendment to Burlington Resources Inc. 1994 Restricted Stock Exchange Plan dated December 2000 (Exhibit 10.16 to Form 10-K, filed February 2001)	*
10.16	Burlington Resources Inc. 1997 Performance Share Unit Plan (Exhibit 10.21 to Form 10-K, filed February 1997)	*

Exhibit Number	Description	
10.17	$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 10-Q filed August 3, 2004)	*
	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)	*
10.18	Form of The Louisiana Land and Exploration Company Deferred Compensation Arrangement for Selected Key Employees (Exhibit 10(g) to LL&E s Form 10-K, filed March 1991)	*
	Amendment to the LL&E Deferred Compensation Arrangement for Selected Key Employees dated December 21, 1998 (Exhibit 10.26 to Form 10-K, filed February 1999)	*
10.19	The LL&E Supplemental Excess Plan (Exhibit 10(j) to LL&E s Form 10-K, filed March 1993)	*
10.20	Form of agreement on pension related benefits with certain former Seattle holding company office employees, including L. David Hanower (Exhibit 10.26 to Form 10-K, filed March 17, 2000)	*
10.21	Poco Petroleums Ltd. Incentive Stock Option Plan (Form S-8 No. 333-91247, filed November 18, 1999)	*
10.22	Employee Savings Plan for Eligible Employees of Poco Petroleums Ltd. (Exhibit 4.4 to Form S-8 No. 333-95071, filed January 20, 2000)	*
10.23	Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (Exhibit 10.12 to Form 10-K, filed February 1996)	*
	First Amendment to the Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (Exhibit 10.29 to Form 10-Q, filed May 2000)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*
	Amendment No. 2, dated December 19, 2005, to Burlington Resources Inc. Phantom Stock Plan for Non-Employee Directors	

10.24	Burlington Resources Inc. 2000 Stock Option Plan for Non-Employee Directors (Exhibit 10.30 to Form 10-Q, filed August 2000)	*
10.25	Letter agreement regarding Steven J. Shapiro dated October 18, 2000 related to supplemental pension benefits in connection with employment (Exhibit 10.29 to Form 10-K, filed February 2001)	*
10.26	Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.30 to Form 10-K, filed February 2001)	*
	Amendment No. 1, dated January 9, 2002, to Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.3 to Form 10-Q, filed April 2002)	*
	Amendment No. 2, dated July 21, 2004, to Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.2 to Form 10-Q filed August 3, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. 2001 Performance Share Unit Plan (Exhibit 10.1 to Form 10-K filed February 28, 2005)	*
10.27	Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit A to Schedule 14A, filed March 15, 2002)	*
	Amendment No. 1, dated December 2003, to Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.29 to Form 10-K filed February 26, 2004)	*
	Amendment No. 2, dated December 2003, to Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.29 to Form 10-K filed February 26, 2004)	*
	Amendment, dated December 23, 2004, to Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.1 to Form 10-K Filed February 28, 2005)	*
	Amendment No. 3, dated December 19, 2005, to Burlington Resources Inc. 2002 Stock Incentive Plan	
	Amendment No. 4, dated January 25, 2006, to Burlington Resources Inc. 2002 Stock Incentive Plan	

Exhibit Number	Description	
10.28	Burlington Resources Inc. 1997 Employee Stock Incentive Plan (Exhibit 10.33 to Form 10-K filed March 12, 2003)	*
	Amendment, dated December 2003, to Burlington Resources Inc. 1997 Employee Stock Incentive Plan (Exhibit 10.30 to Form 10-K, filed February 26, 2004)	*
	Amendment No. 4, effective July 28, 2005 to Burlington Resources Inc. 1997 Employee Stock Incentive Plan (Exhibit 10.1 to Form 10-Q, filed August 3, 2005)	*
	Amendment No. 5, dated December 19, 2005, to Burlington Resources Inc. 1997 Employee Stock Incentive Plan	
	Amendment No. 6, dated January 25, 2006, to Burlington Resources Inc. 1997 Employee Stock Incentive Plan	
10.29	Form of stock option grant letter under the Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.1 to Form 8-K filed January 31, 2006)	*
10.30	Form of restricted stock grant letter under the Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit 10.2 to Form 8-K filed January 31, 2006)	*
10.31	Burlington Resources Inc. 2005 Performance Share Unit Plan (Exhibit 10.2 to Form 8-K filed January 31, 2005)	*
10.32	Form of performance share unit grant letter under the Burlington Resources Inc. 2005 Performance Share Unit Plan (Exhibit 10.3 to Form 8-K filed January 31, 2005)	*
10.33	Summary of Performance Measures for the Burlington Resources Inc. Incentive Compensation Plan (Exhibit 10.33 to Form 10-K filed February 28, 2005)	*
10.34	Summary of the Compensation of Non-Employee Directors of Burlington Resources Inc. (Exhibit 10.34 to Form 10-K filed February 28, 2005)	*
10.35	Letter Agreement, dated as of December 12, 2005 among Burlington Resources Inc., ConocoPhillips, and Bobby S. Shackouls (Exhibit 10.33 to ConocoPhillips Form S-4 filed January 11, 2006)	*
21.1	Subsidiaries of the Registrant	
23.1		

	Consent of Independent Registered Public Accounting Firm PricewaterhouseCoopers LLP
23.2	Consent of Independent Oil and Gas Consultant Miller and Lents, Ltd.
23.3	Consent of Independent Oil and Gas Consultant Sproule Associates Limited
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 herein by reference as indicated or otherwise not filed.
Exhibit constitutes a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.