form 10-K

Burlington Resources 2002 Annual Report

our results reported

BURLINGTON RESOURCES

CONTENTS

FORM 10-K

BURLINGTON RESOURCES

Burlington Resources Inc.
5051 Westheimer, Suite 1400
Houston, Texas 77056
(713) 624-9500
www.br-inc.com

Below are certain definitions of key technical industry terms used in this Form 10-K.

Bbls	Barrels	MCFE	Thousand Cubic Feet of Gas Equivalent
BCF	Billion Cubic Feet	MMCFE	Million Cubic Feet of Gas Equivalent
BCFE	Billion Cubic Feet of Gas Equivalent	MMBTU	Million British Thermal Units
MBbls	Thousands of Barrels	TCF	Trillion Cubic Feet
MMBbls	Millions of Barrels	TCFE	Trillion Cubic Feet of Gas Equivalent
MCF	Thousand Cubic Feet	DD&A	Depreciation, Depletion and Amortization
MMCF	Million Cubic Feet	NGLs	Natural Gas Liquids

Appraisal well is a well drilled in the vicinity of a discovery or wildcat well in order to evaluate the extent and importance of the discovery.

Artificial lift is the mechanical process of producing well fluids to the surface using a rod, tubing or bottom-hole centrifugal pump.

Basin is a synclinal structure in the subsurface that is composed of sedimentary rock and regarded as a good prospect for exploration.

Call options are contracts giving the holder (purchaser) the right, but not the obligation, to buy (call) a specified item at a fixed price (exercise or strike price) during a specified period. The purchaser pays a nonrefundable fee (the premium) to the seller (writer).

Cash-flow hedges are derivative instruments used to mitigate the risk of variability in cash flows from crude oil and natural gas sales due to changes in market prices. Examples of such derivative instruments include fixed-price swaps, fixed-price swaps combined with basis swaps, purchased put options, costless collars (purchased put options and written call options) and producer three-ways (purchased put spreads and written call options). These derivative instruments either fix the price a party receives for its production or, in the case of option contracts, set a minimum price or a price within a fixed range.

Consumer collar is an option strategy that combines a written put option and a purchased call option. The writer of a consumer collar writes a put option (ceiling) and buys a call option (floor).

Developed acreage is the number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Exploitation is drilling wells in areas proven to be productive.

Dry hole is a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

Fair-value hedges are derivative instruments used to hedge or offset the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment. For example, a contract is entered into whereby a commitment is made to deliver to a customer a specified quantity of crude oil or natural gas at a fixed price over a specified period of time. In order to hedge against changes in the fair value of these commitments, a party enters into swap agreements with financial counterparties that allow the party to receive market prices for the committed specified quantities included in the physical contract.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a ''farm-in,'' while the interest transferred by the assignor is a ''farm-out.''

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Formation is a strata of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

Gross acres or gross wells are the total acres or wells in which a working interest is owned.

Horizon is a zone of a particular formation or that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.

Infill drilling refers to drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by the Company's working interest percentage in the properties.

Oil and NGLs are converted into cubic feet of gas equivalent based on 6 MCF of gas to one barrel of oil or NGLs.

Permeability is a measure of ease with which fluids can move through a reservoir.

Productive well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved reserves represent estimated quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, can be recovered in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests. For complete definitions of proved oil and gas reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved developed reserves are the portion of proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. For complete definitions of proved oil and gas reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Producer collar is an option strategy that combines a written call option and a purchased put option. The writer of a producer collar writes a call option (ceiling) and buys a put option (floor). When the premium received on the call option equals the premium paid for the put option, the collar is known as a zero-cost collar.

Proved undeveloped reserves are the portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion. For complete definitions of proved oil and gas reserves, refer to the Securities and Exchange Commission's Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Put options are contracts giving the holder (purchaser) the right, but not the obligation, to sell (put) a specified item at a fixed price (exercise or strike price) during a specified period. The purchaser pays a nonrefundable fee (the premium) to the seller (writer).

Recompletion is an operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

Reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock and water barriers and is individual and separate from other reservoirs.

Seismic is an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation. (2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional pictures.)

Sour gas is natural gas containing chemical impurities, notably hydrogen sulfide, carbon dioxide or other sulfur compounds.

Spacing is the regulation of the number of wells which can be drilled on a given area of land.

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.

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

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 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 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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

OR

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

Commission file number 1-9971

BURLINGTON RESOURCES INC.

Incorporated in the State of Delaware Employer Identification No. 91-1413284

5051 Westheimer, Suite 1400, Houston, Texas 77056
Telephone: (713) 624-9500
Securities registered pursuant to Section 12(b) of the Act:
Common Stock, par value $.01 per share

Preferred Stock Purchase Rights

The above securities are registered on the New York Stock Exchange.

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes X No ____

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of January 31, 2003 and as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of January 31, 2003: $8,885,621,814 and as of June 28, 2002: $7,649,418,316

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $.01 per share, on January 31, 2003, Shares Outstanding: 201,488,023

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated:

Burlington Resources Inc. definitive proxy statement, to be filed not later than 120 days after the end of the fiscal year covered by this report, is incorporated by reference into Part III.

PART I

ITEMS ONE AND TWO

BUSINESS AND PROPERTIES

Burlington Resources Inc. (BR) is a holding company engaged, through its principal subsidiaries, Burlington Resources Oil & Gas Company LP, The Louisiana Land and Exploration Company (LL&E), Burlington Resources Canada Ltd. (formerly known as Poco Petroleums Ltd.), Canadian Hunter Exploration Ltd. (Hunter), and their affiliated companies (collectively, the Company), in the exploration for and the development, production and marketing of crude oil, NGLs and natural gas. The Company is one of North America's largest producers of natural gas.

On December 5, 2001, the Company consummated a transaction with Hunter valued at approximately U.S. $2.1 billion, resulting in an excess purchase price of approximately $793 million which was reflected as goodwill. This acquisition was funded with cash on hand and proceeds from the issuance of $1.5 billion of fixed-rate notes and $400 million of commercial paper. The transaction was accounted for under the purchase method.

The Hunter acquisition added a portfolio of producing 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, North America's third-largest natural gas field, with approximately 1.5 million gross acres and 17 major producing horizons. The acquisition added estimated proved reserves of 1.3 TCFE along with approximately two million net undeveloped acres. See Note 2 of Notes to Consolidated Financial Statements for more information related to this transaction.

In October 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its portfolio and at December 31, 2001, these properties were classified as held for sale. These properties along with others, which together held approximately 1 TCFE of reserves and yielded 228 MMCFE per day of production, were sold in 2002. Based on the purchase and sale agreements, the divestiture program sales price totaled $1.3 billion. Due to differences between purchase and sale agreement dates and closing dates, the Company generated proceeds, before post closing adjustments, of approximately $1.2 billion. The Company used a portion of these proceeds generated from property sales to retire commercial paper, to repay a $104 million promissory note and for general corporate purposes, including funding a portion of the Company's capital program. The Company also expects to use the remaining proceeds for general corporate purposes, including funding a portion of the Company's future capital program.

In November 1999, BR consummated the acquisition of Poco Petroleums Ltd. valued at approximately $2.5 billion. The transaction was funded through the issuance of 38,393,135 shares of the Company's Common Stock and was accounted for under the pooling of interests method.

The Company's reportable segments are U.S., Canada and Other International. For financial information related to the Company's reportable segments, see Note 14 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 the Arctic coast of Canada. The Company's North American operations include a mix of production, development and exploration assets.

In 2002, oil and gas capital expenditures for the Company's U.S. operations totaled $463 million and consisted of $246 million for development projects, $39 million for exploration and $178 million for proved reserve acquisitions. U.S. production in 2002 represented 53 percent of the Company's total production and included 949 MMCF of natural gas per day, 35.4 MBbls of crude oil per day and 32.7 MBbls of NGLs per day. At December 31, 2002, proved reserves in the U.S. totaled 7.3 TCFE and represented 64 percent of the Company's total proved reserves.

In 2002, oil and gas capital expenditures for the Company's Canadian operations totaled $839 million and consisted of $348 million for development projects, $139 million for exploration and $352 million for proved reserve acquisitions, primarily a property acquisition from ATCO Gas and Pipeline Ltd. (ATCO). The Company's Canadian production in 2002 represented 39 percent of the Company's total production and included 802 MMCF of natural gas per day, 27.4 MBbls of NGLs per day and 7.8 MBbls of crude oil per day. At December 31, 2002, Canadian proved reserves totaled 2.7 TCFE and represented 24 percent of the Company's total proved reserves.

In 2002, the Company identified 15 to 20 areas for pilot testing and potential future development, which the Company describes as unconventional resource projects. Unconventional resource projects are defined as tight gas, basin-centered gas, coalbed methane, fractured shale and biogenic gas projects. The Company spent approximately $30 million evaluating these projects during 2002 and advanced the Barnett Shale program, in the Ft. Worth Basin, to the development stage. The Company is continuing to evaluate the remaining projects.

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 acreage in this area with over 848,000 net acres under its control. The Company operates over 6,900 well completions in the San Juan Basin and holds interests in an additional 4,000 non-operated well completions. During the second quarter of 2002, the Company sold the Val Verde gathering and processing facilities and all associated equipment including 360 miles of gathering lines and 14 compressor stations.

In 2002, the Company invested $125 million in oil and gas capital that included over 240 new wells and approximately 290 workovers of existing wells. The Company's net production from the San Juan Basin averaged approximately 569 MMCF of natural gas per day, 28.2 MBbls of NGLs per day and 1.3 MBbls of crude oil per day during 2002. A majority of the growth in the San Juan Basin during the 1990s came from production of coalbed methane gas from the Fruitland Coal formation. To mitigate Fruitland Coal production decline, the Company has an ongoing program that consists of performing workovers on existing wells, adding compression and installing artificial lift, where appropriate. The Company also continued to develop additional Fruitland Coal reserves by drilling new wells on 320-acre spacing, and added 62 BCFE of proved undeveloped reserves. In 2002, net production from the Fruitland Coal averaged 217 MMCF of natural gas per day from over 1,500 wells.

In 2002, the New Mexico Oil and Gas Conservation Division (NMOCD) granted approval to allow infill drilling to 160-acre spacing in the lower-productivity portion of the Fruitland Coal pool. The Company conducted a successful pilot test of the concept during 2001.

Beginning in 1997, with the Fruitland Coal play reaching maturity, the Company began placing greater emphasis on increasing production from conventional gas-producing formations, such as the Mesaverde, the Pictured Cliffs and the Dakota. The Mesaverde formation, which consists of the Lewis Shale, Cliffhouse, Menefee and Point Lookout sands, is the largest producing conventional formation in the San Juan Basin. In 2002, the Company continued its ongoing infill drilling program in this formation. This brought total proved undeveloped reserves added in the Mesaverde formation over the last five years to more than 450 BCFE and the Company has subsequently developed just over half of these reserves. In 2002, net production from the conventional gas-producing formations averaged 323 MMCF of natural gas per day and 28.2 MBbls of NGLs per day.

In the first quarter of 2002, the Company also received approval from the NMOCD to infill drill the Dakota formation. As a result of the increased spacing order and a complete reservoir assessment, during 2002 the Company added 255 BCFE of proved undeveloped reserves in the formation. In addition, the Company drilled 11 80-acre Dakota wells in 2002 and has interests in over 5,000 additional undrilled 80-acre Dakota locations.

In the Pictured Cliffs formation, during 2002 the Company, in partnership with two other operators, received approval from the NMOCD to complete 30 pilot wells on 80-acre spacing, in lieu of the 160-acre spacing currently permitted. This pilot will evaluate whether more wells are needed to extract the Pictured Cliffs formation's remaining gas. Basin wide, the Pictured Cliffs formation has yielded 3.6 TCF gross of natural gas from 6,200 wells. The Company operates about one-third of these wells and owns interests in many others. This pilot testing is expected to allow a more thorough evaluation of this potentially significant reservoir.

During 2002, the Company continued its cost management efforts in the San Juan Basin. Year-over-year, net operated capital costs were reduced approximately $5 million from comparable projects in 2001 as a result of a variety of process improvements. Similarly, lease operating expenses were essentially the same as in 2001, despite inflationary and operational cost pressures. This was achieved primarily through compression optimization and salt water disposal cost savings.

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 79 MMCF of natural gas per day in 2002 and came 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 2002 totaled $19 million for approximately 20 newly drilled wells and workover projects in the deep Madison and shallower formations and $21 million on plant construction. During 2002, the Company completed and commissioned the Lost Cabin Gas Plant Train III, which increased total plant inlet capacity to 310 MMCF of sour gas per day and plant tail gate capacity to 200 MMCF of natural gas per day. The Company also initiated production from two new deep Madison wells, the Big Horn #7-34 and Big Horn #8-35, and began drilling the final deep Madison well, the Big Horn #9-4, which is expected to begin production in late 2003. The Company owns an approximate 50 percent working interest in the plant and a 42 percent revenue interest in the Madison reservoir.

Williston Basin

The Williston Basin operations, in western North Dakota and eastern Montana, are now focused on the Cedar Creek Anticline area, following the divestiture in late 2002 of non-core producing assets located in the northern portion of the basin and characterized by their high cost structure. Total Williston Basin production averaged 14.0 MBbls of oil per day and 7 MMCF of natural gas per day. The Cedar Creek Anticline produced the largest portion of the total, with 11.1 MBbls of crude oil per day and 4 MMCF of natural gas per day. During 2002, the Company invested $32 million on drilling and workover projects in the Williston Basin. The Company continued its highly active waterflood development program in the Cedar Hills South Unit by drilling 23 new wells and increasing water injection volumes. The Company also completed implementation of an 8-well infill-drilling pilot in the East Lookout Butte Unit. This pilot will be monitored during 2003 to further assess the feasibility of drilling infill wells on 160-acre spacing to improve the efficiency of the waterflood.

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. The Company controls over 250,000 net acres and produces from multiple horizons ranging in depth from 11,000 feet to over 21,000 feet. Net production from the Anadarko Basin averaged 91 MMCF of natural gas per day and 1.4 MBbls of NGLs per day in 2002. During 2002, the Company invested $5 million in the Anadarko Basin.

Permian Basin

Permian Basin operations, in west Texas and southeast New Mexico, are now focused on the Waddell Ranch Field. Total Permian Basin production in 2002 averaged 30 MMCF of natural gas per day, 1.6 MBbls of NGLs per day and 5.1 MBbls of crude oil per day, with the Waddell Ranch Field contributing 12 MMCF of natural gas per day, 1.3 MBbls of NGLs per day and 3.1 MBbls of crude oil per day. During 2002, the Company invested $4 million in Permian Basin operations. In mid-2002, the Company divested non-core Permian Basin operations, including the Sonora Field, all characterized by their high cost structure and limited growth opportunities.

Fort Worth Basin

The Fort Worth Basin, in north central Texas, is a new area of operations for the Company. Production during 2002 averaged 6 MMCF of natural gas per day and 0.2 MBbls of NGLs per day. The Company invested $29 million in oil and gas expenditures during the year in the Fort Worth Basin. After initially entering the basin by successfully testing an unconventional resource project, the Barnett Shale, on leasehold located in Wise County, Texas, the Company acquired a larger position located primarily in Denton County, Texas, for $141 million, and ultimately drilled a total of 40 wells during 2002.

Onshore Gulf Coast

The Onshore Gulf Coast includes a number of drilling trends in south Louisiana, as well as 660,000 acres of fee lands where the Company owns the mineral rights and surface lands. Net production from south Louisiana in 2002 averaged 79 MMCF of natural gas per day, 5.3 MBbls of crude oil per day and 0.4 MBbls of NGLs per day. The Company invested $41 million of oil and gas capital and participated in a total of 52 Onshore Gulf Coast projects in 2002. During the year, the Company also divested substantially all of its south and east Texas assets in order to focus its activities on onshore south Louisiana, specifically on development and exploration projects in and around core assets. The divested properties were characterized by their high cost structure and limited growth opportunities.

Gulf of Mexico Shelf

The Company previously held producing interests in the Gulf of Mexico Shelf, but over the past few years has de-emphasized its Gulf of Mexico Shelf activities due to the area's high cost structure and high production decline rates. The Company divested substantially all of its assets in the Gulf of Mexico Shelf during 2002.

Canada

Western Canadian Sedimentary Basin

In the Western Canadian Sedimentary Basin, the Company's portfolio of opportunities includes conventional exploration and development in Alberta, British Columbia and Saskatchewan, as well as frontier exploration of the Mackenzie Delta in the Northwest Territories.

A key focus of Canadian activity during 2002 was on integrating and growing the assets acquired through the acquisitions of Hunter in December 2001 and the ATCO properties, in the Viking-Kinsella area, in January 2002. These assets represent opportunities to expand existing programs into large scale, repeatable drilling programs in conventional and lower permeability zones.

Oil and gas capital investment in Canada during 2002 was $839 million, including acquisitions, and resulted in the completion of 579 wells and the recompletion of 167 wells. During the year, the Company sold certain non-core, high-cost oil and gas properties which contributed to improving the cost structure of the Canadian assets. Throughout the year, continued emphasis on cost control and the lower lease operating expenses of the former Hunter and ATCO assets resulted in a reduction in average lease operating expenses in 2002.

The Deep Basin area, in Alberta and British Columbia, consists of the Elmworth, Wapiti, Noel and Brassey Fields and largely represents properties acquired from Hunter. As a result of a successful drilling program in 2002, 198 MMCF of gas per day and 15.5 MBbls of NGLs per day were produced from the Deep Basin. In 2002, a $120 million oil and gas capital program was focused on exploration and development in the Deep Basin area. A total of 116 wells were drilled in the basin in 2002.

As part of the Deep Basin 2002 program, a tight gas development project largely targeting the Cadomin and Chinook formations was implemented. A recompletion program was focused on testing tight gas concepts in existing multi-zone wellbores. Additionally, regulatory approval was obtained to reduce the normal well spacing requirements from 640 acres to 320 acres in the Cadomin interval in a 33-section area.

The O'Chiese and Whitecourt areas in central Alberta, yielded 2002 production of 226 MMCF of natural gas per day, 8.0 MBbls of NGLs per day and 2.5 MBbls of crude oil per day. The O'Chiese and Whitecourt areas were the focus of a $156 million exploration and development program in 2002 that mostly targeted the Lower Cretaceous and Jurassic sands, the principal historical targets in these areas. At O'Chiese in 2002, the Company completed a regional study of a shallow gas exploration program and drilled 21 wells in this area. The Company has an 800 section land position within this area.

In the Wolf area, 26 wells were drilled, adding 28 MMCF of natural gas per day. In addition, a five-well program to reduce spacing from 640 acres to 320 acres was implemented and resulted in an additional net production of 11 MMCF of natural gas per day. As a result of the successful drilling program, an expansion of the wholly-owned Wolf Plant and gathering system is expected to increase production from 32 MMCF of natural gas per day to 44 MMCF of natural gas per day and is targeted for early 2003. At Alder, 28 wholly-owned successful wells were drilled into the Rock Creek and Lower Cretaceous Ostracod sands with net initial production of 51 MMCF of natural gas per day and 1.9 MBbls of crude oil per day.

The Company added assets in the Ring Border area on the border of northern Alberta and British Columbia as a result of the Hunter acquisition. Production during 2002 averaged 66 MMCF of natural gas per day and 1.3 MBbls of NGLs per day and the focus of activity was on the development and expansion of this asset base. The capital program in this area was $27 million in 2002 which targeted the Bluesky and Gething formations and resulted in 53 successful wells.

Production from the outlying area along the border, between Alberta and British Columbia, averaged 58 MMCF of natural gas per day, 1.0 MBbls of NGLs per day and 0.7 MBbls of crude oil per day. The Company invested $42 million of oil and gas capital in this area to drill 34 wells. An exploration and development program focused on drilling for Slave Point reefs resulted in seven successful wells, the most notable being a discovery north of the prolific Ladyfern Field. This discovery well and a development well are anticipated to come onstream in early 2003.

In the Kaybob area, production for the year averaged 45 MMCF of natural gas per day and 0.4 MBbls of NGLs per day and the Company invested $54 million in the area during 2002. An expansion of the wholly-owned Berland River gas plant commissioned in December 2002 resulted in an increase in production from 8 MMCF of natural gas per day to 23 MMCF of natural gas per day. During 2002, 32 wells were drilled in the Cretaceous and Lower Gething formations.

During 2002, the Company added interests in the Viking-Kinsella area through the ATCO property acquisition. These assets yielded average production of 61 MMCF of natural gas per day during the year. Capital investments during 2002 totaled $34 million and included development drilling in the Viking and Mannville formations. New compressors were installed and a gas processing plant was started up in September 2002, a month ahead of schedule. During the year, the Company acquired 3-D seismic over a 125,000 acre area and drilled eight wells.

Beaufort Basin

In the McKenzie Delta, a 3-D seismic program funded by partners was shot on the Company's exploration acreage. The partners also agreed to drill a well on the North Langley prospect in the first quarter of 2003. The Company incurred no expenditures in this area during 2002.

Other International

The Company's Other International operations include a combination of exploration projects, large field development projects and production operations. Other International production in 2002 represented 8 percent of the Company's total production and included 165 MMCF of natural gas per day and 5.9 MBbls of crude oil per day. At December 31, 2002, Other International proved reserves totaled 1.4 TCFE and represented 12 percent of the Company's total proved reserves. In 2002, oil and gas capital investments for Other International operations totaled $299 million and consisted of $185 million for development projects, $40 million for exploration and $74 million for proved reserve acquisitions. Key focus areas are Northwest Europe, North Africa, the Far East and South America.

Northwest Europe

Operations in Northwest Europe provided the majority of the Company's production outside of North America during 2002, largely from assets in the East Irish Sea and in the Dutch sector of the North Sea.

The East Irish Sea assets consist of 10 licenses covering 267,000 acres. The Company has a 100 percent working interest in seven operated gas fields. First production from two sweet gas fields, Dalton and Millom, commenced in the third quarter of 1999. Early in 2002, the last of six producing wells drilled at Millom was completed. Net production from the East Irish Sea averaged 97 MMCF of natural gas per day during 2002 and the Company invested $128 million in capital.

In 2002, the development of the sour gas fields in the East Irish Sea continued with first production planned in early 2004. During 2002, an offshore production facility was installed, with a pipeline and new onshore processing terminal currently under construction to receive and process the sour gas prior to sale.

During 2002, the Company divested its interests in the Brae and T-Block complexes in the United Kingdom sector of the North Sea due to their limited growth opportunities. The Company's remaining Northwest European Shelf operations consist of non-operated production from the CLAM joint venture in the Dutch offshore sector with net production of 25 MMCF of natural gas per day in 2002.

North Africa

In North Africa, the appraisal and development of oil and gas fields in Algeria have resulted in 37 wells being drilled, including 13 exploration wells. The Company invested $138 million in Algeria in 2002. Significant achievements occurred in the Company-operated Menzel Lejmat Block 405a in the Algerian Berkine Basin, where work advanced on the first phase development project in which the Company currently has a 65 percent working interest. First oil production from this project is expected mid-year 2003 from the MLN and associated fields on the northern part of the block, at a net rate that is expected to reach about 13.0 MBbls of crude oil per day. Exploitation Licence Applications were also submitted during 2002 to Sonatrach, the Algerian national oil company, for ratification and Ministry approval for the next phase of development of oil fields in the southern part of the block from the MLSE area. Work continues on the potential commercialization of the significant gas discoveries that have been made on the block.

Meanwhile, first production was achieved during 2002 in the Ourhoud Field, a portion of which extends onto Block 405a. Crude oil began flowing into newly constructed facilities in November 2002 with the first exports of crude oil for sale occurring in January 2003. The Company has a 3.7 percent working interest in the Ourhoud Field.

In addition, the Company has a 75 percent working interest in Akfadou Block 402d, also in the Berkine Basin. During 2002, the Company acquired over 500 square kilometers (km) of 3-D seismic data on this block. The data has been processed and interpreted and work is underway to finalize a location for the first commitment exploration well.

In Egypt, the Company has a 50 percent working interest in the Offshore North Sinai contract area. The partners contemplate drilling an additional appraisal well. The subsequent project definition and contract award for front-end engineering and design for the planned gas project is expected to follow in late 2003 or early 2004.

Far East

In the Far East, the Company continued to focus on selected basins in China, with an offshore oil development program scheduled for start-up in 2003, and an onshore gas development program working toward long-term commercialization. The Company is also targeting opportunities to add to its existing leasehold position. The Company invested $49 million in China in 2002.

During the year, work on the Panyu offshore oil development project in the Pearl River Mouth Basin of the South China Sea continued with fabrication of all components well underway. The Panyu development involves two offshore oil fields, Bootes and Ursa, located in Block 15/34, in which the Company holds a 24.5 percent working interest. These fields contain net proved reserves of 14.7 MMBbls of crude oil and first production is expected in the second half of 2003.

Onshore, the Company holds a 100 percent working interest in the Chuanzhong Block in the Sichuan Basin, a natural gas project currently in the appraisal phase. The project represents an opportunity to apply the Company's expertise in the development of tight gas reservoirs in an area with substantial reserve potential. Significant milestones achieved in 2002 included the signing of a long-term gas marketing agreement and the submittal of a plan of development for the Bajiaochang Field. Completion of the appraisal program and initiation of development is expected to occur in 2003.

South America

The Company's efforts in South America during 2002 focused on expanding near-term production potential, enhancing long-term exploration opportunities and reducing the number of countries in which the Company operates. During the year, the Company divested its 13.7 percent working interest in the Casanare concession area in Colombia. Production from South America averaged 3.0 MBbls of crude oil per day and 18 MMCF of natural gas per day and the Company invested $90 million of capital in South America during the year.

In Ecuador, capital investments totaled $79 million in 2002. An acquisition in Blocks 7 and 21 resulted in a 30 percent working interest in Block 7 and a 37.5 percent working interest in Block 21. Development drilling commenced in the Yuralpa Field in Block 21, with initial production planned for year-end 2003, provided pipeline construction is completed. Seismic operations also began in Block 7, as did permitting for development drilling during 2003. Block 7 average net production for the year was 2.7 MBbls of crude oil per day.

The Company also reached agreement to farm-out half of its share of Ecuador Blocks 23 and 24 to Perenco Ltd. This will ultimately result in the Company holding a 25 percent working interest in Block 23 and a 50 percent working interest in Block 24.

In Peru, the Company holds a 23.9 percent working interest in Block 35 and a 20 percent interest in Block 34, both located in the Ucayali Basin, 100 km north of Camisea. Elsewhere in Peru, a field geological study and a 293-km 2-D seismic acquisition program were completed in Block 87 in an effort to develop multiple prospects from previously identified leads.

In Argentina, the Company holds a 25.7 percent working interest in the Sierra Chata concession in the Neuquen Basin. This asset has a gross sales capacity of 200 MMCF of natural gas per day from 39 producing wells. During 2002, gas sales were curtailed due to low gas prices in Argentina, with production thus averaging only 18 MMCF of natural gas per day net. Deferrals of capital programs and a close focus on operating costs have helped mitigate the economic impact of an approximate 70 percent devaluation of the Argentine peso.

West Africa

The Company participated in unsuccessful exploratory drilling offshore Angola and Gabon during 2002. In Angola, the Company participated as a 25 percent working interest holder in a well on the Kangandala prospect in Block 21. This $3 million net dry hole was the second commitment well on the block. The Company also holds a 25 percent working interest in each of the Mpolo, Chauillu and Meboun blocks in Gabon. One well was drilled in each block in 2002 but all proved uneconomical.

Productive Wells

Working interests in productive wells at December 31, 2002 follow.

	Gross	Net
North America		
U.S.		
Gas	10,568	6,291
Oil	2,739	1,610
Canada		
Gas	4,641	3,570
Oil	1,155	597
Other International		
Gas	174	54
Oil	100	43
Worldwide		
Gas	15,383	9,915
Oil	3,994	2,250

Net Wells Drilled

Drilling activity in 2002 was principally in the Western Canadian Sedimentary, San Juan, Onshore Gulf Coast, Ft. Worth, Permian, Anadarko, Wind River and Williston Basins. The following table sets forth the Company's net productive and dry wells.

Year Ended December 31,	**2002**	**2001**	**2000**
North America			
U.S.			
Productive			
Exploratory	4.5	6.0	1.2
Development	158.6	271.0	159.6
Dry			
Exploratory	6.3	8.5	3.9
Development	2.1	10.1	5.2
Total Net Wells—U.S.	171.5	295.6	169.9
Canada			
Productive			
Exploratory	73.3	22.9	56.5
Development	320.8	158.8	73.4
Dry			
Exploratory	44.7	13.4	44.1
Development	46.2	48.3	17.0
Total Net Wells—Canada	485.0	243.4	191.0
Other International			
Productive			
Exploratory	0.1	2.1	3.2
Development	1.5	5.8	2.4
Dry			
Exploratory	2.0	3.1	2.1
Development	0.1	0.1	0.1
Total Net Wells—Other International	3.7	11.1	7.8
Worldwide			
Productive			
Exploratory	77.9	31.0	60.9
Development	480.9	435.6	235.4
Dry			
Exploratory	53.0	25.0	50.1
Development	48.4	58.5	22.3
Total Net Wells—Worldwide	660.2	550.1	368.7

As of December 31, 2002, 67 gross wells, representing approximately 48 net wells, were being drilled.

Acreage

Working interests in developed and undeveloped acreage at December 31, 2002 follow.

	Gross	Net
North America		
U.S.		
Developed Acres	4,882,611	2,619,716
Undeveloped Acres	10,243,918	8,506,237
Canada		
Developed Acres	3,313,745	2,235,166
Undeveloped Acres	5,846,763	4,114,377
Other International		
Developed Acres	625,813	210,164
Undeveloped Acres	23,107,665	9,367,373
Worldwide		
Developed Acres	8,822,169	5,065,046
Undeveloped Acres	39,198,346	21,987,987

Capital Expenditures

Following are the Company's capital expenditures.

Year Ended December 31,	2002	2001	2000
		($ Millions)	
North America			
U.S.			
Oil and Gas Activities	$ 463	$ 583	$ 412
Plants & Pipelines	28	70	56
Administrative	35	20	19
Total U.S.	526	673	487
Canada			
Oil and Gas Activities	839	2,282	316
Plants & Pipelines	29	276	20
Administrative	8	5	4
Total Canada	876	2,563	340
Other International			
Oil and Gas Activities	299	217	179
Plants & Pipelines	136	—	—
Administrative	—	1	6
Total Other International	435	218	185
Worldwide			
Oil and Gas Activities	1,601	3,082	907
Plants & Pipelines	193	346	76
Administrative	43	26	29
Total Worldwide	$1,837	$3,454	$1,012

In 2002, worldwide capital expenditures of $1,601 million for oil and gas activities include 49 percent for development, 13 percent for exploration and 38 percent for proved property acquisitions. Proved property acquisitions are primarily related to the property acquisition from ATCO and the acquisition of properties located in Wise and Denton Counties, Texas. Included in capital expenditures for oil and gas activities are exploration costs expensed under the successful efforts method of accounting.

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. Following are the Company's average daily production and average sales prices.

Year Ended December 31,	2002	2001	2000
North America			
U.S.			
Production			
Gas (MMCF per day)	949	1,121	1,265
NGLs (MBbls per day)	32.7	34.6	36.1
Oil (MBbls per day)	35.4	44.0	51.6
Average Sales Price			
Gas, including hedging (per MCF)	$ 3.39	$ 3.99	$ 3.31
Gas, (gain) loss on hedging (per MCF)	(0.25)	0.78	0.63
Gas, excluding hedging (per MCF)	3.14	4.77	3.94
NGLs (per Bbl)	13.23	14.75	17.70
Oil, including hedging (per Bbl)	23.16	22.63	24.18
Oil, (gain) loss on hedging (per Bbl)	(0.24)	1.58	3.50
Oil, excluding hedging (per Bbl)	$22.92	$24.21	$27.68
Canada			
Production			
Gas (MMCF per day)	802	433	341
NGLs (MBbls per day)	27.4	12.5	11.1
Oil (MBbls per day)	7.8	11.9	12.5
Average Sales Price			
Gas, including hedging (per MCF)	$ 3.15	$ 4.60	$ 4.10
Gas, (gain) loss on hedging (per MCF)	(0.06)	(0.12)	(0.05)
Gas, excluding hedging (per MCF)	3.09	4.48	4.05
NGLs (per Bbl)	15.92	22.50	25.38
Oil, including hedging (per Bbl)	28.32	26.51	29.06
Oil, (gain) loss on hedging (per Bbl)	—	—	1.01
Oil, excluding hedging (per Bbl)	$28.32	$26.51	$30.07
Other International			
Production			
Gas (MMCF per day)	165	170	118
Oil (MBbls per day)	5.9	7.3	9.6
Average Sales Price			
Gas, including hedging (per MCF)	$ 2.27	$ 2.83	$ 2.57
Gas, (gain) loss on hedging	(0.08)	—	—
Gas, excluding hedging	2.19	2.83	2.57
Oil (per Bbl)	$24.30	$23.42	$27.73
Worldwide			
Production			
Gas (MMCF per day)	1,916	1,724	1,724
NGLs (MBbls per day)	60.1	47.1	47.2
Oil (MBbls per day)	49.1	63.2	73.7
Average Sales Price			
Gas, including hedging (per MCF)	$ 3.19	$ 4.03	$ 3.42
Gas, (gain) loss on hedging	(0.16)	0.48	0.45
Gas, excluding hedging (per MCF)	3.03	4.51	3.87
NGLs (per Bbl)	14.46	16.79	19.51
Oil, including hedging (per Bbl)	24.11	23.45	25.44
Oil, (gain) loss on hedging (per Bbl)	(0.18)	1.10	2.62
Oil, excluding hedging (per Bbl)	$23.93	$24.55	$28.06

Production Unit Costs

The Company's production unit costs follow. Production costs consist of production taxes and well operating costs.

Year Ended December 31,	2002	2001	2000
		(per MCFE)	
North America			
U.S.			
Average Production Costs	$0.62	$0.69	$0.57
Average Production Taxes	0.20	0.26	0.22
DD&A Rates	0.66	0.75	0.74
Canada			
Average Production Costs	0.38	0.65	0.69
Average Production Taxes	0.02	0.02	0.03
DD&A Rates	0.97	0.77	0.67
Other International			
Average Production Costs	0.32	0.21	0.31
Average Production Taxes	0.02	0.01	—
DD&A Rates	1.02	1.05	0.83
Worldwide			
Average Production Costs	0.50	0.64	0.57
Average Production Taxes	0.12	0.18	0.16
DD&A Rates	$0.81	$0.78	$0.73

Reserves

The following table sets forth estimates by the Company's petroleum engineers of proved oil, NGLs and gas reserves at December 31, 2002. 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, 2002	Proved Developed	Proved Undeveloped	Total Proved Reserves
North America			
U.S.			
Gas (BCF)	3,617	1,136	4,753
NGLs (MMBbls)	179.2	61.2	240.4
Oil (MMBbls)	155.2	32.0	187.2
Total U.S. (BCFE)	5,623	1,696	7,319
Canada			
Gas (BCF)	1,836	460	2,296
NGLs (MMBbls)	53.1	6.7	59.8
Oil (MMBbls)	12.9	1.5	14.4
Total Canada (BCFE)	2,232	509	2,741
Other International			
Gas (BCF)	263	578	841
Oil (MMBbls)	12.9	73.4	86.3
Total Other International (BCFE)	340	1,018	1,358
Worldwide			
Gas (BCF)	5,716	2,174	7,890
NGLs (MMBbls)	232.3	67.9	300.2
Oil (MMBbls)	181.0	106.9	287.9
Total Worldwide (BCFE)	8,196	3,222	11,418

Miller and Lents, Ltd. and Sproule Associates Limited, independent oil and gas consultants, have reviewed the estimates of proved reserves of natural gas, oil and NGLs that BR attributed to its net interests in oil and gas properties as of December 31, 2002. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and international interests (excluding Canada and Argentina) and Sproule Associates Limited reviewed the Company's interests in Canada and Argentina. 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 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

Competition—The Company actively competes for reserve acquisitions, exploration leases and sales of oil and gas, frequently against companies with substantially larger financial and other resources. In its marketing activities, the

Company competes with numerous companies for the sale of oil, gas and NGLs. Competitive factors in the Company's business include price, contract terms, quality of service, pipeline access, transportation discounts and distribution efficiencies.

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 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, the reclamation and abandonment of wells, sites and facilities 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;
- 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. 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 continue to evolve. 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. 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. 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, because regulatory requirements frequently change and may become more stringent and as with other companies engaged in similar businesses, 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.

Filings of Reserve Estimates With Other Agencies—During 2002, the Company filed estimates of its oil and gas reserves for the year 2001 with the Department of Energy. These estimates differ by 5 percent or less from the reserve data presented. For information concerning proved oil, NGLs and gas reserves, see page 58.

Employees

The Company had 2,003 and 2,167 employees at December 31, 2002 and 2001, respectively. At December 31, 2002, 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. In addition, the Company has adopted a Code of Business Conduct and Ethics 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.

ITEM THREE

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.

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 royalty disputes 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 $68 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could also 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. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings 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.

The Company has also been named as a defendant in the lawsuit styled *UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al,* No. 98-854, filed in 1995 in the District Court in The Hague and currently pending in the Court of Appeal in The Hague, the Netherlands. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.5 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a Judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeal in The Hague issued an interim Judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. The Company and the other defendants are continuing to present evidence to the Court and vigorously assert defenses against these claims. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. The Company is unable at this time to reasonably predict the outcome, or, in the event of an unfavorable outcome, to reasonably estimate the possible loss or range of loss, if any, in this lawsuit. Accordingly, there has been no reserve established for this matter.

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 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 of these other lawsuits and proceedings cannot be predicted with certainty, management believes that the resolution of these other matters will not have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

The Company has established reserves for legal proceedings which are included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves a complex 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 of up to approximately $25 million to $30 million in excess of the amounts currently accrued. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued.

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 2002.

EXECUTIVE OFFICERS OF THE REGISTRANT

Bobby S. Shackouls, 52—Chairman of the Board, President and Chief Executive Officer, Burlington Resources Inc., July 1997 to present. President and Chief Executive Officer, Burlington Resources Oil & Gas Company, October 1994 to June 1998.

Randy L. Limbacher, 44—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. President and Chief Executive Officer, Burlington Resources Oil & Gas Company, July 1998 to December 2000. Vice President, Gulf Coast Division, Burlington Resources Oil & Gas Company, February 1997 to June 1998.

Steven J. Shapiro, 50—Executive Vice President and Chief Financial Officer, Burlington Resources Inc., December 2002 to present. Senior Vice President and Chief Financial Officer, Burlington Resources Inc., October 2000 to December 2002. Senior Vice President, Chief Financial Officer and Director, Vastar Resources, Inc., 1993 to September 2000.

L. David Hanower, 43—Senior Vice President, Law and Administration, Burlington Resources Inc., July 1998 to present. Senior Vice President, Law, Burlington Resources Inc., April 1996 to June 1998.

John A. Williams, 58—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. Senior Vice President, Exploration, Burlington Resources Oil & Gas Company, July 1998 to December 2000. Senior Vice President, Exploration, Burlington Resources Inc., October 1997 to June 1998.

PART II

ITEM FIVE

MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's common stock, par value $.01 per share (Common Stock) is traded on the New York Stock Exchange under the symbol ''BR'' and on the Toronto Stock Exchange under the symbol ''B.'' At December 31, 2002, the number of holders of Common Stock was 16,273. Information on Common Stock prices and quarterly dividends is shown on page 60 under the subheading ''Quarterly Financial Data — Unaudited.'' See also ''Equity Compensation Plan Information'' under Part III, Item 12 of this report.

ITEM SIX

SELECTED FINANCIAL DATA

The selected financial data for the Company set forth below for the five years ended December 31, 2002 should be read in conjunction with the consolidated financial statements and accompanying notes thereto.

	2002	2001	2000	1999	1998
	(In Millions, Except per Share Amounts)				
INCOME STATEMENT DATA					
Revenues	$ 2,964	$ 3,419	$3,218	$2,359	$2,225
Income (Loss) Before Income Taxes and Cumulative Effect of Change in Accounting Principle	569	907	967	(13)	(624)
Net Income (Loss)	454	561	675	(10)	(338)
Basic Earnings (Loss) per Common Share	2.26	2.71	3.13	(0.05)	(1.60)
Diluted Earnings (Loss) per Common Share	2.25	2.70	3.12	(0.05)	(1.60)
Cash Dividends Declared per Common Share	$ 0.55	$ 0.55	$ 0.55	$ 0.46	$ 0.46
BALANCE SHEET DATA					
Total Assets	$10,645	$10,582	$7,506	$7,165	$7,060
Long-term Debt	3,853	4,337	2,301	2,769	2,684
Stockholders' Equity	$ 3,832	$ 3,525	$3,750	$3,229	$3,312
Common Shares Outstanding	201	201	216	216	216

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

BR 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, primarily from its properties located in the Rocky Mountain natural gas fairway of North America, complemented by several key international projects. 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 the start-up and delivery of several key projects.

The Company has adopted a very disciplined capital allocation process, with the objective of achieving modest 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, BR 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 is often beyond the Company's control, and ''commercial'', which includes commodity price volatility, local price differentials in its various areas of operations and attention to operating margins. Each of these factors is complex, challenging and highly variable.

To address subsurface risks, BR utilizes most 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. The Company has put considerable emphasis in recent years 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 maintain production. 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. BR 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. BR 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 to the Company's operations.

At BR, managing the commercial risks is an ongoing priority. 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 very 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, BR will from time to time use various financial tools to hedge the price it will receive for a particular commodity in the future. The primary purpose of these activities is to provide for adequate financial returns on the significant investments that the Company makes annually to replenish its productive base and grow its reserves while leaving as much commodity price upside as possible for the Company's stockholders. Margin enhancement is another important element in BR's business, including attention to cash operating and administrative costs 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 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 commodity itself — 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 are 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 which are valued in the public market place daily. Because these three asset classes are not always valued consistently with each other, opportunities may exist from time to time to take advantage of these various valuation differences. These valuation differences are key to BR's capital allocation philosophy.

At BR, there are three types of investment alternatives that constantly compete for available capital. These include drilling opportunities, acquisition opportunities and financial opportunities such as share repurchases and debt repayment. Depending on circumstances and the relative valuations of the asset classes described above, BR allocates capital among its investment alternatives which is 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 BR'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

The Company expects full year production volumes in 2003 to average between 2,573 and 2,708 MMCFE per day. In 2003, the Company is expected to experience some gas equivalent production decreases as a result of property sales in 2002 and natural declines. However, the Company expects to offset these production declines with new projects such as the Lost Cabin Gas Plant expansion in Madden Field in Wyoming, which was completed during the third quarter of 2002, the Ourhoud Field in Algeria and other projects that are anticipated to start-up during 2003 such as crude oil development projects in the MLN Field in Algeria and the Bootes and Ursa offshore Fields in China.

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 volatile. Commodity prices are affected by changes in 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 effect increases or decreases in production volumes will have on future revenues.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to the Company's long-term success. In 2002, the Company spent approximately $1.2 billion on development, exploration and plants and pipeline capital and an additional $604 million on acquisitions. In 2002, the Company's reserve replacement costs were $1.03 per MCFE excluding acquisitions or $1.06 per MCFE including acquisitions. The Company replaced 161 percent of its worldwide production from all sources and 103 percent of its worldwide production excluding acquisitions during 2002.

On June 30, 2002, the Company sold the Val Verde gathering and processing plant (Val Verde Plant), which contributed $19 million in third party revenues in 2002. As a result of the sale, in addition to the future revenue loss, the Company expects its transportation expenses to increase approximately $40 million annually offset partially by lower operating expenses of approximately $11 million and lower DD&A of approximately $9 million. The Company has certain wells that qualify for Section 29 Tax Credits. In 2002, the Company generated $16 million of Section 29 Tax Credits. Production from qualified wells ceased to generate Section 29 Tax Credits at the end of 2002.

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, 2002 and December 31, 2001 was 51 percent and 55 percent, respectively. The reduction in total debt to total capital was accomplished by the use of proceeds from the disposal of assets and the generation of cash flows from operations. Based on the current price environment, the Company believes that it will generate sufficient cash from operations to fund the 2003 capital expenditures, excluding potential acquisitions. At December 31, 2002, the Company had $443 million of cash and cash equivalents on hand.

In February 2002, Burlington Resources Finance Company (BRFC) issued $350 million of 5.7% Notes due March 1, 2007 (February Notes), which were fully and unconditionally guaranteed by BR. The proceeds from the February Notes were used to retire commercial paper that was issued to finance the acquisition of certain assets from ATCO Gas and Pipeline Ltd. (ATCO). The February Notes reduced the Company's amount available under its shelf registration statement on file with the Securities and Exchange Commission (SEC) to $397 million. In May 2002, the Company restored its shelf registration statement to $1,500 million.

In June 2002, the Company retired a $100 million 8¼% Note. To retire the 8¼% Note, the Company issued a $104 million promissory note at a per annum rate equal to the sum of Eurodollar rates plus 0.70 percent. The $104 million promissory note was retired on September 16, 2002. During 2002, the Company also retired $675 million of net commercial paper and had no commercial paper outstanding at December 31, 2002.

In June 2002, the Company commenced an offer to exchange outstanding 5.6% Notes due 2006, 6.5% Notes due 2011 and 7.4% Notes due 2031, which were issued by BRFC and fully and unconditionally guaranteed by BR, in a private offering in November 2001 (Private Notes), for a like principal amount of 5.6% Notes due 2006, 6.5% Notes due 2011 and 7.4% Notes due 2031 to be issued by BRFC, fully and unconditionally guaranteed by BR and registered under the Securities Act of 1933, as amended (Registered Notes). In July 2002, following the expiration of the exchange offer, the Company issued the Registered Notes. All of the Private Notes were exchanged for Registered Notes and the Private Notes were cancelled.

Burlington Resources Capital Trust I, Burlington Resources Capital Trust II (collectively, the Trusts), BR and BRFC have a shelf registration statement on file with the SEC as mentioned above. Pursuant to such 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 had credit commitments in the form of revolving credit facilities (Revolvers) as of December 31, 2002. The Revolvers are comprised of agreements for $600 million, $400 million and Canadian $468 million (U.S. $296 million). The $600 million Revolver expires in December 2006 and the $400 million and Canadian $468 million Revolvers expire in December 2003 unless renewed by mutual consent. The Company has the option to convert any remaining balances on the $400 million and Canadian $468 million Revolvers to one-year and five-year plus one day term notes, respectively. Under the covenants of the Revolvers, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements). The Revolvers are available to cover 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, 2002, there are no amounts outstanding under the Revolvers and no outstanding commercial paper.

Net cash provided by operating activities in 2002 was $1,549 million compared to $2,106 million and $1,598 million in 2001 and 2000, respectively. The decrease in 2002 compared to 2001 was primarily due to lower net income, excluding non-cash items. Net income was lower principally as a result of lower natural gas and NGLs prices and lower oil sales volumes partially offset by higher natural gas and NGLs sales volumes. The increase in 2001 compared to 2000 was primarily due to higher net income, excluding non-cash items, resulting primarily from higher natural gas prices and lower working capital needs.

The Company has various commitments primarily related to leases for office space, other property and equipment and demand charges on firm transportation agreements for its production of natural gas. The Company expects to fund these commitments with cash generated from operations. The following table summarizes the Company's contractual obligations at December 31, 2002.

		Payments Due by Period			
Contractual Obligation	**Total**	**Less than 1 Year**	**1-2 Years**	**3-4 Years**	**After 4 Years**
			(In Millions)		
Total debt(1)	$3,957	$ 63	$ —	$ 944	$2,950
Non-cancellable operating leases(2)	249	44	53	40	112
Drilling rig commitments(2)	104	72	32	—	—
Transportation demand charges(2)	863	140	202	166	355
Total Contractual Obligations	$5,173	$319	$287	$1,150	$3,417

(1) See discussion of long-term debt above and Note 7 of Notes to Consolidated Financial Statements.
(2) See Note 11 of Notes to Consolidated Financial Statements for discussion of these commitments.

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, two Canadian transportation agreements and a natural gas purchase agreement. 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.

While the mark-to-market positions under the hedging agreements and the natural gas purchase agreement 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, 2002, the aggregate unfavorable mark-to-market position under the aforementioned hedging agreements was approximately $13 million. A rating change would have had no impact on the Company related to the natural gas purchase agreement since the mark-to-market position under such agreement was favorable to the Company. 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 $27 million as of December 31, 2002.

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 site restoration and dismantlement, royalty payments and exploration programs where governmental organizations require such support.

Changes in credit rating also impact the cost of borrowing under the Company's Revolvers, but have no impact on availability of credit under the agreements. The Revolvers are filed as exhibits 10.18, 10.19 and 10.31 to this Form 10-K.

The Company has investments in three entities that it accounts for under the equity method. The book values of the Company's interests in Lost Creek Gathering Company, L.L.C. (Lost Creek), Evangeline Gas Pipeline Company (Evangeline) and CLAM Petroleum B.V. (CLAM) are $13 million, $2 million and $31 million, respectively. As of December 31, 2002, CLAM had no outstanding debt, Lost Creek had outstanding debt totalling $52 million and Evangeline had outstanding debt totalling $43 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. At December 31, 2002, the Company also owns a 1.5 percent interest in a foreign entity that is accounted for at cost. The Company is the guarantor of approximately $14 million of the entity's total outstanding debt.

In December 2000, the Company's Board of Directors authorized the repurchase of up to $1 billion of the Company's Common Stock. During 2002, the Company repurchased none of its Common Stock. Through December 31, 2002, the Company has repurchased approximately 16.3 million shares or $693 million of its Common Stock under this $1 billion authorization.

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

Capital Expenditures and Resources

Capital expenditures in 2002 totaled $1,837 million compared to $3,454 million and $1,012 million in 2001 and 2000, respectively. The Company invested $997 million on internal development and exploration of oil and gas properties during 2002 compared to $1,085 million and $858 million in 2001 and 2000, respectively. The Company invested $604 million on property acquisitions in 2002 compared to $1,997 million and $49 million in 2001 and 2000, respectively. Property acquisitions in 2002 included the purchase of certain assets, located in the Viking-Kinsella area, in January 2002 from ATCO, a Canadian regulated gas utility, for approximately $344 million and $141 million for the purchase of certain oil and gas properties located in Wise and Denton Counties, Texas in August 2002. The Company also invested $193 million on plants and pipelines in 2002 compared to $346 million and $76 million in 2001 and 2000, respectively. Property acquisitions and plants and pipelines in 2001 primarily included assets from the Canadian Hunter Exploration Ltd. (Hunter) acquisition. See Note 2 of Notes to Consolidated Financial Statements for additional information regarding the Hunter acquisition. Capital expenditures in 2003, excluding proved property acquisitions, are expected to be approximately $1.4 billion. Capital expenditures in 2003 are expected to be primarily for internal development and exploration of oil and gas properties and plant and pipeline expenditures. Capital expenditures are expected to be funded from internal cash flows.

During the fourth quarter of 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its portfolio, primarily in the U.S. Due to their high cost structure, high production volume decline rates and limited growth opportunities, substantially all of the Gulf of Mexico Shelf and south and east Texas assets were included in the non-core, non-strategic properties. During 2002, the Company completed the sale of certain non-core, non-strategic properties, including the Val Verde Plant. Based on the purchase and sale agreements, the divestiture program sales price totaled $1.3 billion. Due to differences between purchase and sale agreement dates and closing dates, the Company generated proceeds, before post closing adjustments, of approximately $1.2 billion and recognized a net pretax gain of $68 million. The producing properties that were sold during the year generated $202 million, $401 million and $416 million of revenues and incurred $140 million, $478 million and $336 million of direct operating expenses during the years 2002, 2001 and 2000, respectively. The Company used a portion of the proceeds generated from property sales to retire commercial paper, to repay the $104 million promissory note and for general corporate purposes, including funding a portion of the Company's capital program. The Company also expects to use the remaining proceeds for general corporate purposes, including funding a portion of the Company's future capital program.

In connection with the divestiture program, the Company also recorded a restructuring liability of $10 million in the fourth quarter of 2001. As of December 31, 2002, all of the restructuring liability had been paid.

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.

Other International

The Company's Other 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 local sales points based on spot or contract prices.

Qualitative and Quantitative Disclosure About Market Risk

Commodity Risk

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

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

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires enterprises to recognize all derivatives as either assets or liabilities on the balance sheet and measure 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 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 uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of crude oil and natural gas may have on the fair value of the Company's derivative instruments. For example, at December 31, 2002, 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 $97 million decrease in the net unrealized gain. The derivative instruments in place at December 31, 2002 hedged approximately 30 percent of the Company's expected natural gas production volumes through 2003.

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 the 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 established formal internal control procedures which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to counterparties through formal credit policies and monitoring procedures. In the normal course of business, collateral is not required for financial instruments with credit risk.

Foreign Currency Risk

The Company's reported cash flows related to its Canadian operating subsidiaries are based on cash flows measured in Canadian dollars and converted to the U.S. dollar equivalent based on the average of the Canadian and U.S. dollar exchange rates for the period reported. The Company's Canadian operating subsidiaries have no financial obligations that are denominated in U.S. dollars.

Dividends

On January 22, 2003, the Board of Directors declared a common stock quarterly cash dividend of $0.1375 per share, payable April 1, 2003 to shareholders of record on March 7, 2003. Dividend levels are determined by the Board of Directors based on profitability, capital expenditures, financing and other factors. The Company declared cash dividends on Common Stock totaling approximately $111 million and paid dividends totaling approximately $139 million during 2002. During the year, the Company paid five quarterly dividends, including fourth quarter 2002, which normally would have been paid in January 2003.

Application of Critical Accounting Policies

Oil and Gas Reserves

The process of estimating quantities of natural gas, NGLs and crude oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. As described in Note 1 of Notes to Consolidated Financial Statements, the Company uses the unit-of-production method to amortize 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. See the Supplementary Financial Information for reserve data.

Successful Efforts Method of Accounting

The Company accounts for its oil and gas properties using the successful efforts method of accounting for its exploration and development activities. Acquisition and development costs are capitalized and amortized using the unit-of-production method based on proved and proved developed reserves estimated by the Company's reserve engineers. Changes in reserve quantities as described below will cause corresponding changes in depletion expense in periods subsequent to the quantity revision. Unsuccessful exploration or dry hole wells are expensed 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 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 proved crude oil, NGLs and natural gas reserves, future crude oil, NGLs and natural gas prices and costs to extract these reserves. Downward revisions in estimated reserve quantities, increases in future cost estimates or depressed crude oil, NGLs and natural gas prices could cause the Company to reduce the carrying amounts of its properties. See Note 13 of Notes to Consolidated Financial Statements for impairment of oil and gas properties.

Costs attributable to the Company's unproved properties 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. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year 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.

Goodwill

As described in Note 3 of Notes to Consolidated Financial Statements, the Company accounts for goodwill in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires an annual impairment assessment in lieu of periodic amortization. The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. These estimates are based on future net cash flows and are based upon management's estimates of proved reserves as well as the success of future exploration for and development of unproved reserves. Downward revisions of estimated reserve quantities, increases in future cost estimates or depressed crude oil, NGLs and natural gas prices could lead to an impairment of all or a portion of goodwill in future periods.

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded on 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 estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for crude oil, natural gas 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 a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. 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, 2002 Compared With Year Ended December 31, 2001

The Company reported net income of $454 million or $2.25 diluted earnings per common share in 2002 compared to net income of $561 million or $2.70 diluted earnings per common share in 2001. Net income in 2002 included a net after tax gain of $46 million or $0.23 per diluted share related to the disposal of assets and the reversal of a tax valuation reserve of $27 million or $0.13 per diluted share related to the sale of assets in the United Kingdom (U.K.) sector of the North Sea. Net income in 2002 included an after tax loss of $14 million or $0.07 per diluted share compared to an after tax gain of $6 million or $0.03 per diluted share in 2001 consisting of ineffectiveness related to cash-flow and fair-value hedges. Net income in 2002 also included an after tax loss of $6 million or $0.03 per diluted share compared to an after tax gain of $6 million or $0.03 per diluted share in 2001 related to changes in the fair value of derivative instruments that do not qualify for hedge accounting.

Revenues

Revenues decreased $455 million to $2,964 million in 2002 from $3,419 million in 2001. The $455 million decrease in revenues primarily consists of $627 million related to lower natural gas and NGLs prices and higher crude oil prices, $31 million due to lower revenues related to ineffectiveness on cash-flow and fair-value hedges, $20 million due to lower revenues related to changes in the fair value of derivative instruments that do not qualify for hedge accounting and $22 million due to the sale of the Val Verde Plant in the second quarter of 2002. These decreases in revenues were partially offset by increased revenues of $241 million related to higher gas and NGLs sales volumes and lower oil sales volumes. Details of commodity prices and sales volumes variances are described below.

Price Variances

Average natural gas prices, including a $0.16 realized gain per MCF related to hedging activities, decreased $0.84 per MCF in 2002 to $3.19 per MCF from $4.03 per MCF, including a $0.48 loss per MCF related to hedging activities, in 2001. Lower average natural gas prices resulted in decreased revenues of $588 million during 2002. Imbedded in the average natural gas prices during 2002 was also the impact of location basis differentials that varied widely compared to the same period in 2001 primarily in the western U.S. and western Canada. Average NGLs prices decreased $2.33 per barrel in 2002 to $14.46 per barrel from $16.79 per barrel in 2001, resulting in reduced revenues of $51 million during 2002. Average crude oil prices, including an $0.18 realized gain per barrel related to hedging activities, increased $0.66 per barrel in 2002 to $24.11 per barrel from $23.45 per barrel, including a $1.10 loss per barrel related to hedging activities, in 2001. Higher average crude oil prices resulted in increased revenues of $12 million during 2002.

Volume Variances

Average natural gas sales volumes increased 192 MMCF per day in 2002 to 1,916 MMCF per day from 1,724 MMCF per day in 2001, resulting in increased revenues of $282 million during 2002. Average NGLs sales volumes increased 13.0 MBbls per day in 2002 to 60.1 MBbls per day from 47.1 MBbls per day in 2001, resulting in higher revenues of $80 million during 2002. Average crude oil sales volumes decreased 14.1 MBbls per day in 2002 to 49.1 MBbls per day from 63.2 MBbls per day in 2001, reducing revenues $121 million during 2002. Average natural gas sales volumes in Canada increased 369 MMCF per day primarily due to the acquisitions of Hunter in late 2001 and ATCO in early 2002 and an aggressive drilling program. The increase of 369 MMCF per day in Canada was partially offset by reductions of 172 MMCF per day resulting from natural declines in production and asset sales in the Onshore Gulf Coast, the Gulf of Mexico Shelf, the San Juan Basin and the Permian Basin. Average NGLs sales volumes in Canada also increased 14.9 MBbls per day primarily due to the acquisition of Hunter. Average crude oil sales volumes decreased 12.4 MBbls per day primarily due to natural declines in production and asset sales in the Gulf of Mexico Shelf, Canada and the Permian Basin.

Total Costs and Other Income—Net

Total costs and other income—net were $2,395 million in 2002 compared to $2,512 million in 2001. Total costs and other income—net in 2001 included $184 million related to the impairment of oil and gas properties held for sale and a restructuring charge of $10 million related to severance and other exit costs. Excluding the $194 million charges in 2001, total costs and other income—net in 2002 increased $77 million. The $77 million increase was primarily due to a $98 million increase in DD&A, an $84 million increase in interest expense, a $28 million increase in exploration costs, a $13 million increase in transportation expenses and a $12 million increase in administrative expenses partially offset by a $60 million increase in gain on disposal of assets, a $43 million decrease in taxes other than income taxes, a $28 million decrease in production and processing expenses, excluding the $10 million restructuring charge in 2001, and a $27 million increase in other income—net.

DD&A increased primarily due to a higher unit-of-production rate related to changes in production resulting from the Canadian acquisitions, which had higher rates than the average unit-of-production rates for the Company. DD&A also increased due to higher natural gas production volumes in Canada. Interest expense increased primarily due to higher debt balances during 2002 resulting from the Hunter acquisition in late 2001 and other property acquisitions consummated in early 2002. Exploration costs increased primarily due to higher amortization of undeveloped lease costs of $54 million, higher drilling rig costs of $17 million and higher geological and geophysical (G&G) and other expenses of $20 million partially offset by lower exploratory dry hole costs of $63 million. The higher drilling rig expenses, which were approximately $40 million during 2002, were attributable to the subletting of a deepwater drilling rig currently under lease to the Company. This $40 million charge covers the anticipated loss for the remaining term of the lease. Transportation expenses increased primarily due to higher contract rates. Administrative expenses increased primarily due to higher payroll and benefits. Gain on disposal of assets was higher due to the divestiture of non-core, non-strategic properties. Taxes other than income taxes decreased primarily due to lower crude oil and natural gas revenues. Production and processing expenses decreased primarily due to lower well operating costs. Other income—net increased primarily due to higher interest income, lower foreign currency transaction losses and lower miscellaneous expenses incurred in 2002 compared to 2001.

Income Tax Expense

Income tax expense was $115 million in the 2002 compared to $349 million in 2001. The decrease in tax expense was primarily due to lower pretax income. The Company also recorded benefits of $86 million in 2002 compared to $20 million in 2001 related to interest deductions allowed in both the U.S. and Canada on transactions associated with cross-border financing entered into in the second half of 2001 and the first quarter of 2002. Year 2002 also included the reversal of a tax valuation reserve of $27 million in September 2002 related to the sale of assets in the U.K. sector of the North Sea. The Company also recorded a benefit of $26 million and $3 million in 2002 and 2001, respectively, due to a reduction in the Alberta provincial corporate tax rate in Canada. The benefit in 2002 was partially offset by an increase in expense of $12 million related to an increase in the U.K.'s income tax rate. Net Section 29 Tax Credits were $1 million in 2002 compared to $24 million in 2001.

Year Ended December 31, 2001 Compared With Year Ended December 31, 2000

The Company reported net income of $561 million or $2.70 diluted earnings per common share in 2001 compared to net income of $675 million or $3.12 diluted earnings per common share in 2000. Net income in 2001 included a non-cash after tax charge of $116 million or $0.56 per diluted share primarily related to the impairment of oil and gas properties held for sale. The Company evaluates the impairment of its 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. In December 2001, primarily as a result of the Company's decision to exit the Gulf of Mexico Shelf and divest of certain other properties, the Company recognized a pretax charge of $184 million ($116 million after tax) related to those properties. The Company also recognized a $6 million after tax restructuring charge or $0.03 per share related to severance and other exit costs. Net income in 2001 also included an after tax gain of $6 million or $0.03 per diluted share related to ineffectiveness on cash-flow and fair-value hedges and an after tax gain of $6 million or $0.03 per diluted share related to changes in the fair value of derivative instruments which do not qualify for hedge accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*. For more discussion of SFAS No. 133, see Note 1 of Notes to Consolidated Financial Statements. The results of operations for 2001 included one month of activities related to the Hunter acquisition.

Revenues

Revenues increased $201 million to $3,419 million in 2001 from $3,218 million in 2000. The $201 million increase in revenues primarily consists of $291 million related to higher natural gas prices and lower crude oil and NGLs prices, $10 million due to higher revenues related to changes in the fair value of derivative instruments that do not qualify for hedge accounting and $9 million related to ineffectiveness on cash-flow and fair-value hedges. These increases in revenues were partially offset by decreased revenues of $107 million related to lower commodity sales volumes.

Price variances

Average natural gas prices, including a $0.48 realized loss per MCF related to hedging activities, increased $0.61 per MCF in 2001 to $4.03 per MCF from $3.42 per MCF, including a $0.45 loss per MCF related to hedging activities, in 2000. Higher average natural gas prices resulted in increased revenues of $384 million during 2001. Average NGLs prices decreased $2.72 per barrel in 2001 to $16.79 per barrel from $19.51 per barrel in 2000, resulting in reduced revenues of $46 million during 2001. Average crude oil prices, including a $1.10 realized gain per barrel related to hedging activities, decreased $1.99 per barrel in 2001 to $23.45 per barrel from $25.44 per barrel, including a $2.62 per barrel related to hedging activities, in 2000. Lower average crude oil prices resulted in reduced revenues of $46 million during 2001.

Volume variances

Average crude oil sales volumes decreased 10.5 MBbls per day in 2001 to 63.2 MBbls per day from 73.7 MBbls per day in 2000, reducing revenues $99 million during 2001. Average natural gas sales volumes were the same as the prior year at 1,724 MMCF per day, however, due to one less day in 2001 compared to 2000, natural gas revenues were down $6 million. Average NGLs sales volumes decreased slightly to 47.1 MBbls per day in 2001 from 47.2 MBbls per day in 2000, resulting in lower revenues of $2 million. Average crude oil sales volumes decreased 8.1 MBbls per day primarily due to natural declines in production and reduced capital spending in the Deepwater Gulf of Mexico, the Gulf of Mexico Shelf and south Louisiana areas and natural declines in production and property sales in 2000 in Other International. Although total natural gas sales volumes were the same as the prior year, average natural gas sales volumes were higher in Canada and the East Irish Sea. Average natural gas sales volumes in Canada increased 92 MMCF per day primarily due to a successful drilling program and the Hunter acquisition in late 2001. Average natural gas sales volumes in the East Irish Sea increased 36 MMCF per day primarily due to an additional interest acquired in the area. These increases were offset primarily due to lower natural gas sales volumes of 128 MMCF per day as a result of lower capital spending in the Gulf of Mexico Shelf and natural declines in production in the San Juan Basin, south Louisiana and Other International.

Total Costs and Other Income—Net

Total costs and other income—net were $2,512 million in 2001 compared to $2,251 million in 2000. The $261 million increase was primarily due to a $184 million increase in impairment of oil and gas properties held for sale, a $35 million increase in production and processing expenses, including $10 million related to severance and other exit costs, a $32 million increase in transportation expenses, a $25 million increase in DD&A, a $21 million increase in exploration costs, a $7 million increase in taxes other than income taxes and a $3 million increase in administrative expenses partially offset by a $33 million increase in other income—net, a $7 million decrease in interest expense and a $6 million increase in gain on disposal of assets.

Production and processing expenses increased primarily due to higher workover expense, higher service, electrical and lease fuel costs. DD&A increased primarily due to a higher unit-of-production rate related to changes in production primarily resulting from the Canadian acquisitions which had higher rates than average unit-of-production rates for the Company and higher finding costs. Exploration costs increased primarily due to higher drilling rig expenses of $29 million and higher exploratory dry hole costs of $28 million partially offset by lower G&G and other expenses of $21 million and lower amortization of undeveloped lease costs of $16 million. Transportation expenses increased primarily due to higher tariffs and taxes other than income taxes increased primarily due to higher crude oil and natural gas revenues. Interest Expense decreased primarily due to higher capitalized interest during 2001. Other income—net increased primarily due to higher interest income in 2001 as a result of excess cash on hand during the year, higher gain on disposal of assets and lower interest expense related to tax matters. Administrative expenses in 2001 compared to 2000 increased $3 million. However, year 2000 administrative expenses included a legal accrual of $32 million related to certain litigation. This $32 million was partially offset by the reversal of a $26 million valuation allowance related to a receivable due from a former affiliate. The Company reversed the $26 million valuation allowance after reevaluating the issues and concluding that it was probable that the receivable would be collected.

Income Taxes

Income tax expense was $349 million in 2001 compared to $292 million in 2000. The increase in tax expense was primarily due to lower tax benefits related to Section 29 Tax Credits and tax-accrual adjustments partially offset by lower tax on 2001 pretax income. Section 29 Tax Credits were $24 million in 2001 compared to $52 million in 2000. Favorable tax-accrual adjustments were $21 million in 2001 compared to $56 million in 2000 primarily related to prior period activity.

Acquisition—2001

On December 5, 2001, the Company consummated a transaction with Hunter valued at approximately U.S. $2.1 billion, resulting in an excess purchase price of approximately $793 million which was reflected as goodwill. This acquisition was funded with cash on hand and proceeds from the issuances of $1.5 billion of fixed-rate notes and $400 million of commercial paper. The transaction was accounted for under the purchase method in accordance with SFAS No. 141. See Note 2 of Notes to Consolidated Financial Statements for more information related to this transaction.

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. 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.

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 royalty disputes 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 $68 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could also 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. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings 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.

The Company has also been named as a defendant in the lawsuit styled *UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al*, No. 98-854, filed in 1995 in the District Court in The Hague and currently pending in the Court of Appeal in The Hague, the Netherlands. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.5 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a Judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeal in The Hague issued an interim Judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. The Company and the other defendants are continuing to present evidence to the Court and vigorously assert defenses against these claims. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. The Company is unable at this time to reasonably predict the outcome, or, in the event of an unfavorable outcome, to reasonably estimate the possible loss or range of loss, if any, in this lawsuit. Accordingly, there has been no reserve established for this matter.

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 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 of these other lawsuits and proceedings cannot be predicted with certainty, management believes that the resolution of these other matters will not have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

The Company has established reserves for legal proceedings which are included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves a complex 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 of up to approximately $25 million to $30 million in excess of the amounts currently accrued. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued.

Other Matters

Recent Accounting Pronouncements

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN No. 46), which addresses consolidation by business enterprises of variable interest entities. FIN No. 46 clarifies the application of Accounting Research Bulletin No. 51, *Consolidated Financial Statements,* to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN No. 46 applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. The Company does not expect to identify any variable interest entities that must be consolidated. In the event a variable interest entity is identified, the Company does not expect the requirements of FIN No. 46 to have a material impact on its consolidated financial condition or results of operations.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* (FIN No. 45). FIN No. 45 requires certain guarantees to be recorded at fair value, which is different from current practice to record a liability only when a loss is probable and reasonably estimable, as those terms are defined in FASB Statement No. 5, Accounting for Contingencies. FIN No. 45 also requires the Company to make significant new disclosures about guarantees. The disclosure requirements of FIN No. 45 are effective for the Company in the first quarter of fiscal year 2003. FIN No. 45's initial recognition and initial measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company's previous accounting for guarantees issued prior to the date of the initial application of FIN No. 45 will not be revised or restated to reflect the provisions of FIN No. 45. The Company does not expect the adoption of FIN No. 45 to have a material impact on its consolidated financial position, results of operations or cash flows.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, ''Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).'' SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred and establishes that fair value is the objective for initial measurement of the liability. The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. The Company adopted SFAS No. 146 on January 1, 2003, but at this time this statement has no effect on the Company's consolidated financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections*. SFAS No. 145, which is effective for fiscal years beginning after May 15, 2002, provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The Company adopted SFAS No. 145 on January 1, 2003, but at this time this statement has no effect on the Company's consolidated financial position or results of operations.

In June 2001, the FASB issued SFAS No. 143, *Accounting for 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 cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Based on current estimates, the Company expects to record a net-of-tax cumulative effect of change in accounting principle loss, in the first quarter of 2003, of approximately $59 million in accordance with the provisions of SFAS No. 143. There will be no impact on the Company's cash flows as a result of adopting SFAS No. 143.

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 expressions. 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. Some of the important factors that could cause actual results to differ from any such projections or other forward-looking statements follow.

Commodity Prices—Changes in crude oil, NGLs and natural gas 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 can also impact the Company's determination of proved reserves and the standardized measure of discounted future net cash flows relative to crude oil, NGLs and natural gas reserves. In addition, periods of sharply lower commodity prices could affect the Company's production levels and/or cause it to curtail capital spending projects and delay or defer exploration, exploitation or development projects.

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, ''Commodity Risk.''

Exploration and Production Risk—The Company's business is subject to all of the risks and uncertainties normally associated with the exploration for and development and production of crude oil, NGLs and natural gas, including uncertainties as the presence, size and recoverability of hydrocarbons. The exploration for crude oil and natural gas is a high-risk business in which significant numbers of dry holes and high associated costs can be incurred in the process of seeking commercial discoveries.

The process of estimating quantities of proved reserves is inherently uncertain and involves subjective engineering, geological, geophysical and economic determinations. 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 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 successful pilot project or the operation of an installed program.

Projecting future crude oil, NGLs and natural gas 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.

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.

Development Risk—A significant portion of the Company's development plans involve large projects in Canada, Algeria, the East Irish Sea, China, 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, 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, delivery schedules for critical equipment and arrangements for the gathering and transportation of the produced hydrocarbons.

Foreign Operations Risk—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 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 crude oil, NGLs and natural gas 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 crude oil, NGLs and natural gas, 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—The Company actively competes for property acquisitions, exploration leases and sales of crude oil, NGLs and natural gas, 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.

Legal and Regulatory Risk—The Company's operations are affected by foreign, national, state and local laws and regulations. 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. 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—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.

Environmental Regulations and Liabilities—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.

ITEM EIGHT

FINANCIAL STATEMENTS AND SUPPLEMENTARY FINANCIAL INFORMATION
BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF INCOME

Year Ended December 31,	2002	2001	2000
	(In Millions, Except per Share Amounts)		
REVENUES	**$2,964**	**$3,419**	**$3,218**
COSTS AND OTHER INCOME—NET			
Taxes Other than Income Taxes	123	166	159
Transportation Expense	350	337	305
Production and Processing	467	505	470
Depreciation, Depletion and Amortization	833	735	710
Exploration Costs	286	258	237
Impairment of Oil and Gas Properties	—	184	—
Administrative	161	149	146
Interest Expense	274	190	197
(Gain)/Loss on Disposal of Assets	(68)	(8)	(2)
Other Expense (Income)—Net	(31)	(4)	29
Total Costs and Other Income—Net	**2,395**	**2,512**	**2,251**
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	569	907	967
Income Tax Expense	115	349	292
Income Before Cumulative Effect of Change in Accounting Principle	454	558	675
Cumulative Effect of Change in Accounting Principle—Net	—	3	—
NET INCOME	**$ 454**	**$ 561**	**$ 675**
EARNINGS PER COMMON SHARE			
Basic			
Before Cumulative Effect of Change in Accounting Principle	$ 2.26	$ 2.70	$ 3.13
Cumulative Effect of Change in Accounting Principle—Net	—	0.01	—
NET INCOME	**$ 2.26**	**$ 2.71**	**$ 3.13**
Diluted			
Before Cumulative Effect of Change in Accounting Principle	$ 2.25	$ 2.69	$ 3.12
Cumulative Effect of Change in Accounting Principle—Net	—	0.01	—
NET INCOME	**$ 2.25**	**$ 2.70**	**$ 3.12**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED BALANCE SHEET

December 31,	2002	2001
	(In Millions, Except Share Data)	
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 443	$ 116
Accounts Receivable	515	398
Commodity Hedging Contracts and Other Derivatives	4	118
Inventories	48	50
Other Current Assets	51	33
	1,061	715
Oil and Gas Properties (Successful Efforts Method)	12,716	16,038
Other Properties	1,140	1,416
	13,856	17,454
Accumulated Depreciation, Depletion and Amortization	5,353	8,623
Properties—Net	8,503	8,831
Goodwill	803	782
Other Assets	278	254
Total Assets	**$10,645**	**$10,582**
LIABILITIES		
Current Liabilities		
Accounts Payable	$ 809	$ 599
Taxes Payable	44	6
Accrued Interest	61	61
Dividends Payable	—	28
Other Current Liabilities	45	17
Current Maturities of Long-term Debt	63	—
	1,022	711
Long-term Debt	3,853	4,337
Deferred Income Taxes	1,436	1,403
Commodity Hedging Contracts and Other Derivatives	33	15
Other Liabilities and Deferred Credits	469	591
Commitments and Contingent Liabilities (Note 11)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.01 per Share (Authorized 75,000,000 Shares; One Share Issued)	—	—
Common Stock, Par Value $.01 per Share (Authorized 325,000,000 Shares; Issued 241,188,688 Shares for both 2002 and 2001)	2	2
Paid-in Capital	3,941	3,944
Retained Earnings	1,675	1,332
Deferred Compensation—Restricted Stock	(9)	(9)
Accumulated Other Comprehensive Loss	(164)	(106)
Cost of Treasury Stock (39,749,431 and 40,395,695 Shares for 2002 and 2001, respectively)	(1,613)	(1,638)
Stockholders' Equity	3,832	3,525
Total Liabilities and Stockholders' Equity	**$10,645**	**$10,582**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

Year Ended December 31,	2002	2001	2000
		(In Millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 454	$ 561	$ 675
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities			
Depreciation, Depletion and Amortization	833	735	710
Deferred Income Taxes	39	219	219
Exploration Costs	286	258	237
Impairment of Oil and Gas Properties	—	184	—
Gain on Disposal of Assets	(68)	(8)	(2)
Changes in Derivative Fair Values	32	(25)	—
Working Capital Changes, Net of Acquisition			
Accounts Receivable	(117)	467	(341)
Inventories	2	6	8
Other Current Assets	(17)	(3)	1
Accounts Payable	138	(187)	109
Taxes Payable	43	(46)	(33)
Accrued Interest	4	23	(3)
Other Current Liabilities	(8)	(2)	4
Changes in Other Assets and Liabilities	(72)	(76)	14
Net Cash Provided By Operating Activities	1,549	2,106	1,598
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Properties	(1,851)	(1,293)	(941)
Acquisition of Hunter, net of cash acquired	—	(2,087)	—
Proceeds from Sales and Other	1,180	1	19
Net Cash Used In Investing Activities	(671)	(3,379)	(922)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from Long-term Debt	454	2,247	70
Reduction in Long-term Debt	(879)	(211)	(564)
Dividends Paid	(139)	(116)	(89)
Common Stock Purchases	—	(684)	(121)
Common Stock Issuances	13	41	92
Debt Issuance Costs and Other	2	(20)	(21)
Net Cash Provided By (Used In) Financing Activities	(549)	1,257	(633)
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	(2)	—	—
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	327	(16)	43
CASH AND CASH EQUIVALENTS			
Beginning of Year	116	132	89
End of Year	**$ 443**	**$ 116**	**$ 132**

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)						
BALANCE, DECEMBER 31, 1999	$ 2	$3,966	$ 328	$(3)	$ (54)	$(1,010)	$3,229
Comprehensive Income (Loss)							
Net Income			675				675
Foreign Currency Translation					(16)		(16)
Comprehensive Income (Loss)			675		(16)		659
Cash Dividends Declared ($0.55 per Share)			(119)				(119)
Common Stock Purchases (3,505,000 Shares)						(125)	(125)
Stock Option Activity and Other		(22)		(2)		130	106
BALANCE, DECEMBER 31, 2000	2	3,944	884	(5)	(70)	(1,005)	3,750
Comprehensive Income (Loss)							
Net Income			561				561
Foreign Currency Translation					(90)		(90)
Cumulative Effect of Change in Accounting Principle—Hedging					(366)		(366)
Hedging Activities					420		420
Comprehensive Income (Loss)			561		(36)		525
Cash Dividends Declared ($0.55 per Share)			(113)				(113)
Common Stock Purchases (16,092,000 Shares)						(684)	(684)
Stock Option Activity						41	41
Issuance of Restricted Stock				(10)		10	—
Amortization of Restricted Stock				6			6
BALANCE, DECEMBER 31, 2001	2	3,944	1,332	(9)	(106)	(1,638)	3,525
Comprehensive Income (Loss)							
Net Income			454				454
Foreign Currency Translation					34		34
Hedging Activities					(86)		(86)
Minimum Pension Liability					(6)		(6)
Comprehensive Income (Loss)			454		(58)		396
Cash Dividends Declared ($0.55 per Share)			(111)				(111)
Stock Option Activity		(3)				16	13
Issuance of Restricted Stock				(9)		9	—
Amortization of Restricted Stock				9			9
BALANCE, DECEMBER 31, 2002	**$2**	**$3,941**	**$1,675**	**$(9)**	**$(164)**	**$(1,613)**	**$3,832**

See accompanying Notes to Consolidated Financial Statements.

BURLINGTON RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Accounting Policies

Principles of Consolidation and Reporting

The consolidated financial statements include the accounts of Burlington Resources Inc. (BR) and its majority-owned subsidiaries (collectively, the Company). 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.

Properties

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. Costs of unproved properties are capitalized and amortized on a composite basis, based on past success experience and average property lives.

The Company evaluates the impairment of its 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 the sum of the expected undiscounted future cash flows is less than the asset's net book value. Cash flows are determined based upon proved 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 NYMEX 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. 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. The Company's abandonment liability, included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet, was $106 million and $201 million at December 31, 2002 and 2001, respectively.

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 on the straight-line method based on expected lives of the individual assets or group of assets.

Revenue Recognition

Natural gas, NGLs and crude oil revenues are recorded on 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 estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for crude oil, natural gas 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. At December 31, 2002 and 2001, product inventory was $5 million and $3 million, respectively. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess 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, 2002 and 2001, the Company had net gas imbalance receivables of $19 million and $39 million, respectively.

Royalty Payable

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

Functional Currency

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 other comprehensive income. 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 foreign entities other than BR's Canadian operating subsidiaries are measured using the U.S. dollar as the functional currency. For 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, 2002, 2001 and 2000 are losses of $1 million, $7 million and $4 million, respectively.

Commodity Hedging Contracts and Other Derivatives

The Company enters into derivative contracts, primarily options and swaps, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. The Company also enters into derivative contracts to mitigate the risk of foreign currency exchange rate fluctuations. On January 1, 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Effective with the adoption of SFAS No. 133, all derivatives were 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, the gain or loss on the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is either recognized in income along with an offsetting adjustment to the basis 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 when a hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of options used in cash-flow hedges rather than changes of intrinsic value only. As a result, changes in the entire fair value of option contracts are deferred in accumulated other comprehensive income until the hedged transaction affects earnings to the extent such contracts are effective. 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 production is discontinued in instances where the related fair-value hedging instrument becomes ineffective. The balance in the fair-value hedge adjustment account is recorded in income when the related production is delivered. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged production are included in revenues and are included in realized prices in the period that the related production is delivered. 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 also 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. The Company attempts to minimize credit risk exposure to counterparties through formal credit policies and monitoring procedures. Generally, collateral is not required for financial instruments with credit risk.

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.

Stock-based Compensation

At December 31, 2002, the Company has three stock-based employee compensation plans, which are described more fully in Note 9.

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 2002, 2001 and 2000 were $10.83, $13.35 and $10.33, respectively. The fair values of employee stock options were calculated using a variation of the Black-Scholes stock option valuation model with the following weighted average assumptions for grants in 2002, 2001 and 2000: stock price volatility of 31 percent, 35 percent and 35 percent, respectively; risk free rate of return ranging from 3 percent to 5 percent; dividend yield of 1.43 percent, 1.32 percent and 1.46 percent, respectively; and an expected term of 3 to 5 years.

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee compensation. The fair value of stock options included in the pro forma amounts is not necessarily indicative of future effects on net income and earnings per common share (EPS).

Year Ended December 31,	**2002**	**2001**	**2000**
	(In Millions, Except per Share Amounts)		
Net income—as reported	$ 454	$ 561	$ 675
Pro forma stock based employee compensation cost, after tax (unaudited)	11	12	12
Net income—pro forma (unaudited)	$ 443	$ 549	$ 663
Basic EPS—as reported	$ 2.26	$ 2.71	$ 3.13
Basic EPS—pro forma (unaudited)	2.21	2.65	3.08
Diluted EPS—as reported	2.25	2.70	3.12
Diluted EPS—pro forma (unaudited)	$ 2.20	$ 2.64	$ 3.06

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 that 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

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 201 million, 207 million and 216 million for the years ended December 31, 2002, 2001 and 2000, respectively. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The weighted average number of common shares outstanding for computing diluted EPS, including dilutive stock options, was 202 million, 208 million and 216 million for the years ended December 31, 2002, 2001 and 2000, respectively. For the years ended December 31, 2002, 2001 and 2000, approximately 4 million shares attributable to the exercise of outstanding options were excluded from the calculation of diluted EPS because the effect was antidilutive. The Company has no preferred stock or other convertible securities affecting EPS, and therefore, no adjustments related to preferred stock or other convertible securities 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 oil, NGLs and gas reserve volumes and the future development, dismantlement and abandonment costs as well as estimates relating to certain gas, NGLs and oil revenues and expenses. Actual results could differ from those estimates.

2. Business Combination and Other Property Acquisitions and Divestitures

Other Property Acquisitions—2002

In August 2002, the Company purchased certain oil and gas properties located in Wise and Denton Counties, Texas for $141 million. On January 3, 2002, the Company consummated a property acquisition, for properties located in the Viking-Kinsella area, from ATCO Gas and Pipelines Ltd. (ATCO), a Canadian regulated gas utility, for approximately $344 million.

Acquisition of Canadian Hunter Exploration Ltd. (Hunter)—2001

On December 5, 2001, BR acquired all of the outstanding shares of Hunter valued at approximately U.S. $2.1 billion, resulting in an excess purchase price of approximately $793 million which was reflected as goodwill. This acquisition was funded with cash on hand and proceeds from the issuances of $1.5 billion of fixed-rate notes and $400 million of commercial paper. The transaction was accounted for under the purchase method in accordance with SFAS No. 141. The results of operations of Hunter were included in the Company's financial statements effective December 5, 2001. The purchase price was calculated as follows.

	(In Millions)
Calculation of purchase price for assets acquired	
Cash paid for stock purchased	$2,014
Cash settlement of employee stock options	66
Other purchase price costs (e.g. fees, etc.)	17
Cash acquired	(10)
Total purchase price for common equity	2,087
Plus fair market value of liabilities assumed	
Current and other liabilities	308
Deferred tax	902
Total liabilities	1,210
Total purchase price for assets acquired	$3,297

Other purchase price costs relate primarily to professional fees of approximately $16 million and other direct transaction costs of approximately $1 million.

The following is the allocation of the purchase price to specific assets and liabilities based on estimates of fair values and costs. All of the goodwill was assigned to the Company's Canadian reporting unit.

	(In Millions)
Current assets	$ 74
Other assets	45
Properties, plant and equipment	2,385
Goodwill	793
	3,297
Current liabilities	(105)
Other liabilities	(194)
Long-term debt	(9)
Deferred tax	(902)
	$2,087

The following table presents the unaudited pro forma results of the Company as though the acquisition had occurred on January 1, 2000. Pro forma results are not necessarily indicative of actual results.

	2001	**2000**
	(In Millions, Except per Share Amounts)	
Revenues	$3,902	$3,648
Net income	696	757
Basic earnings per common share	3.36	3.51
Diluted earnings per common share	$ 3.34	$ 3.50

Divestitures

During the fourth quarter of 2001, the Company announced its intent to sell certain non-core, non-strategic properties in order to improve the overall quality of its portfolio, primarily in the U.S. Due to their high cost structure, high production volume decline rates and limited growth opportunities, substantially all of the Gulf of Mexico Shelf and south and east Texas assets were included in the non-core, non-strategic properties. During 2002, the Company completed the sale of certain non-core, non-strategic properties, including the Val Verde Plant. Based on the purchase and sale agreements, the divestiture program sales price totaled $1.3 billion. Due to differences between purchase and sale agreement dates and closing dates, the Company generated proceeds, before post closing adjustments, of approximately $1.2 billion and recognized a net pretax gain of $68 million. The producing properties that were sold during the year generated $202 million, $401 million and $416 million of revenues and incurred $140 million, $478 million and $336 million of direct operating expenses during the years 2002, 2001 and 2000, respectively. The Company used a portion of the proceeds generated from property sales to retire commercial paper, to repay the $104 million promissory note and for general corporate purposes, including funding a portion of the Company's capital program. The Company also expects to use the remaining proceeds for general corporate purposes, including funding a portion of the Company's future capital program.

In connection with the divestiture program, the Company also recorded a restructuring liability of $10 million in the fourth quarter of 2001. As of December 31, 2002, all of the restructuring liability had been paid.

3. Goodwill

Effective January 1, 2002, the Company adopted SFAS No. 142, *Goodwill and Other Intangible Assets.* SFAS No. 142 requires the Company to test goodwill for impairment rather than amortize. Under the transition provisions of SFAS No. 142, goodwill acquired in a business combination for which the acquisition date is after June 30, 2001 is not to be amortized and is to be reviewed for impairment under existing standards until adoption of SFAS No. 142 on January 1, 2002. The entire goodwill balance of $803 million at December 31, 2002, which is not deductible for tax purposes, is related to the acquisition of Hunter on December 5, 2001. Accordingly, the Company recorded no goodwill amortization during 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.

All of the goodwill was assigned to the Company's Canadian reporting unit which consists of all of the Company's Canadian subsidiaries. The initial adoption of SFAS No. 142 required the Company to perform a two-step fair value based goodwill impairment test as of January 1, 2002. The first step of the test compares the book value of the Company's reporting unit to its estimated fair value. The second step of the goodwill impairment test is only required if the net book value of the reporting unit exceeds the fair value. The second step of the goodwill impairment test compares the implied fair value of goodwill in accordance with the methodology prescribed by SFAS No. 142 to its book value to determine if an impairment is required. During the second quarter of 2002, the Company completed the first step of its impairment analysis related to its goodwill and determined that the Company's fair value of its Canadian reporting unit exceeded its net book value at January 1, 2002, thereby eliminating the need for the second step.

In addition to the initial impairment test, SFAS No. 142 requires companies to test goodwill for impairment annually. The Company performed step one of its annual goodwill impairment test in the fourth quarter of 2002 and determined that the fair value of the Company's Canadian reporting unit exceeded its net book value as of September 30, 2002. Therefore, step two was not required.

The following table reflects the changes in the carrying amount, including the final purchase accounting adjustment, of goodwill during the year as it relates to the Canadian reporting unit.

	(In Millions)
Balance—January 1, 2002	$782
Changes in foreign exchange rates during the period	7
Purchase accounting adjustments related to foreign income taxes and other	14
Balance—December 31, 2002	$803

4. Oil and Gas and Other Properties

Oil and gas properties consisted of the following.

December 31,	**2002**	**2001**
	(In Millions)	
Proved properties	$11,441	$14,556
Unproved properties	1,275	1,482
	12,716	16,038
Accumulated depreciation, depletion and amortization	5,077	8,060
Oil and gas properties—net	$ 7,639	$ 7,978

Other properties consisted of the following.

December 31,	**Depreciable Life-Years**	**2002**	**2001**
		(In Millions)	
Plants and pipeline systems	10-20	$ 804	$ 979
Land, building, improvements and furniture and fixtures	0-40	111	145
Data processing & telecommunications equipment	3-7	152	229
Other	3-15	73	63
		1,140	1,416
Accumulated Depreciation		276	563
Other properties—net		$ 864	$ 853

5. Income Taxes

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

Year Ended December 31,	2002	2001	2000
		(In Millions)	
Domestic	$ 548	$ 470	$ 673
Foreign	21	437	294
Total	$ 569	$ 907	$ 967

The provision for income taxes follows.

Year Ended December 31,	2002	2001	2000
		(In Millions)	
Current			
Federal	$ 37	$ 25	$ 37
State	11	19	10
Foreign	28	86	26
	76	130	73
Deferred			
Federal	63	76	84
State	4	14	15
Foreign	(28)	129	120
	39	219	219
Total	$ 115	$ 349	$ 292

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

Year Ended December 31,	2002	2001	2000
U.S. statutory rate	35.0%	35.0%	35.0%
State income taxes	1.7	2.3	2.3
Taxes on foreign income in excess of U.S. statutory rate	9.4	8.5	4.5
Effect of change in foreign income tax rate	(2.3)	(0.3)	—
Section 29 tax credits(1)	(0.2)	(2.6)	(5.4)
Cross-border financing benefit	(15.1)	(2.2)	—
Other(2)	(8.4)	(2.3)	(6.2)
Effective rate	20.1%	38.4%	30.2%

(1) In 2002, the tax benefit associated with section 29 tax credits was reduced by $16 million (2.9%) as a result of the 1996-1998 federal income tax audit. Adjustments related to section 29 tax credits certification issues of $7 million (–0.7%) and $34 million (–3.5%) were made in 2001 and 2000, respectively.

(2) In 2002, other primarily consisted of the reversal of a $27 million (–4.8%) tax valuation reserve related to the sale of assets in the U.K. Sector of the North Sea. In 2000, other primarily consisted of a $28 million (–2.9%) reserve related to tax sharing agreements between former affiliated companies.

Deferred income tax liabilities (assets) follow.

December 31,	**2002**	**2001**
	(In Millions)	
Deferred income tax liabilities		
Property, plant and equipment	$1,868	$1,875
Commodity hedging contracts and other derivatives	—	33
	1,868	1,908
Deferred income tax assets		
AMT credit carryforward	(307)	(347)
Deferred foreign tax credits	—	(55)
Foreign net operating loss carryforwards	(17)	(2)
Commodity hedging contracts and other derivatives	(21)	—
Financial accruals and other	(121)	(178)
	(466)	(582)
Less valuation allowance	34	77
	$1,436	$1,403

The net deferred income tax liabilities at December 31, 2002 and 2001 include deferred state income tax liabilities of approximately $53 million and $49 million, respectively. The net deferred income tax liabilities also include foreign tax liabilities of approximately $1,119 million and $1,102 million at December 31, 2002 and 2001, 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. It is not practicable to estimate the deferred tax liability related to such undistributed earnings.

The Alternative Minimum Tax (AMT) credit carryforward, related primarily to nonconventional fuel tax credits, is available to offset future federal income tax liabilities. The AMT credit carryforward has no expiration date. Of the $17 million tax benefit for operating loss carryforwards, which relate to foreign jurisdictions, $2 million has no expiration date, $14 million will expire after 2007 and $1 million will expire between 2003 and 2007.

6. Commodity Hedging Contracts and Other Derivatives

The Company uses derivative instruments to manage risks associated with natural gas, crude oil and electricity price volatility as well as foreign currency exchange rate fluctuations. Derivative instruments that meet the hedge criteria in SFAS No. 133 are designated as cash-flow hedges, fair-value hedges, or foreign-currency 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 crude oil and natural gas 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. In addition to hedges of commodity prices, the Company also uses foreign-currency swaps to hedge its exposure to exchange rate fluctuations related to its Canadian subsidiaries.

Cash-Flow Hedges

At December 31, 2002, the Company's cash-flow hedges consisted of fixed-price swaps, producer collars (purchased put options and written call options), producer three-ways (purchased put spreads and written call options), purchased call options combined with either the costless collars or producer three-ways and consumer collars (purchased call options and written put options). The fixed-price swap agreements are used to fix the prices of anticipated future natural gas production. The costless collars are used to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The producer three-ways are collars combined with put options that effectively replace the floor of the collars with a fixed premium over the index price in low price environments. In addition, the Company has combined purchased call options with producer collars and producer three-ways to allow the Company to participate in price increases above a specified price. The consumer collars are used to establish floor and ceiling prices on anticipated purchases of electricity. There were no net premiums received when the Company entered into these option agreements.

Fair-Value Hedges

At December 31, 2002, the Company's fair-value hedges consisted of price swaps that 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 crude oil or natural gas 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.

Foreign-Currency Hedges

At December 31, 2002, the Company's foreign-currency hedges consisted of foreign currency swaps used to fix the amount of Canadian dollars a Canadian subsidiary receives on anticipated sales denominated in U.S. dollars.

Derivatives Not Designated as Hedges

The Company also has foreign currency swaps that, prior to September 1, 2002, were collectively designated as a hedge of Hunter's net investment in a U.S. dollar denominated foreign subsidiary. During September 2002, the foreign entity that was the subject of the hedge was transferred to a U.S. subsidiary of the Company and the swaps were de-designated as a hedge.

A summary of the Company's derivative instruments as of December 31, 2002 follows.

			Notional Amount					
Settlement Period	Derivative Instrument	Hedge Strategy	Gas (MMBTU)	Oil (Barrels)	Electricity (Megawatts)	US $ (In Millions)	Average Underlying Price	Fair Value Asset (Liability)
2003	Swap	Cash flow	18,315,630				$ 2.81	$ (17)
	Purchased put	Cash flow	184,325,000				3.16	21
	Written call	Cash flow	184,325,000				4.94	(32)
	Written put	Cash flow	178,850,000				2.36	(3)
	Purchased put	Cash flow		450,000			25.00	—
	Written put	Cash Flow		450,000			20.00	—
	Written call	Cash flow		450,000			30.36	(1)
	Swap	Foreign currency				$ 17	1.42	(2)
	Swap	Fair value	2,699,500				3.06	3
	N/A	Fair value (obligation)	2,699,500				3.13	(3)
	Purchased call	Cash flow			175,200		40.30	1
	Written put	Cash flow			175,200		26.45	(1)
2004	Swap	Cash flow	15,613,289				2.95	(13)
	Swap	Foreign currency				7	1.43	(1)
	Swap	Fair value	2,166,800				2.83	3
	N/A	Fair value (obligation)	2,166,800				2.85	(3)
2005	Swap	Cash flow	10,513,930				2.89	(6)
	Swap	Fair value	1,459,200				2.65	1
	N/A	Fair value (obligation)	1,459,200				2.65	(1)
	Swap	Not designated				$116	1.50	(8)
2006 to 2007	Swap	Cash flow	1,672,500				$ 3.06	(1)
								$ (63)

The derivative assets and liabilities represent the difference between hedged values and market values on hedged volumes of the commodities as of December 31, 2002. During 2002, hedging activities related to cash settlements increased revenues by $114 million. In addition, during 2002, losses of $22 million were recorded in revenues associated with ineffectiveness of cash-flow and fair-value hedges and losses of $10 million were recorded in revenues related to changes in fair value derivative instruments which do not qualify for hedge accounting.

In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, the Company recorded a net-of-tax cumulative-effect-type loss adjustment of $366 million in accumulated other comprehensive income to recognize at fair value all derivatives that were designated as cash-flow hedging instruments. The Company recorded cash-flow hedge derivatives liabilities of $582 million ($361 million after tax), fair value hedge derivative assets of $16 million ($10 million after tax), related liability adjustments to book value of fair-value hedged items of $16 million ($10 million after tax) and an after tax non-cash gain of $3 million was recorded in current earnings as a cumulative effect of accounting change.

Changes in other comprehensive income for the year ended December 31, 2002 follow.

	(In Millions)
Accumulated other comprehensive income hedging activities—December 31, 2001	$ 54
Reclassification adjustments for settled contracts	(68)
Current period changes in fair value of settled contracts	20
Changes in fair value of outstanding hedging positions	(38)
Accumulated other comprehensive loss on hedging activities—December 31, 2002	$ (32)

Based on commodity prices and foreign exchange rates as of December 31, 2002, the Company expects to reclassify losses of $34 million ($21 million after tax) to earnings from the balance in accumulated other comprehensive loss during the next twelve months. At December 31, 2002, the Company had derivative assets of $8 million and derivative liabilities of $71 million of which $4 million and $38 million is included in Other Assets and Other Current Liabilities, respectively, on the Consolidated Balance Sheet.

7. Long-term Debt

Long-term debt follows.

December 31,	**2002**	**2001**
	(In Millions)	
Commercial Paper	$ —	$ 675
Notes, 8¼%, due 2002	—	100
Notes, 6.40%, due 2003	63	63
Notes, 5.60%, due 2006	500	500
Notes, 6.60%, due 2007	94	94
Notes, 5.70%, due 2007	350	—
Debentures, 9⅞%, 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, 7⅝%, due 2013	100	100
Debentures, 9⅛%, due 2021	150	150
Debentures, 7.65%, due 2023	88	88
Debentures, 8.20%, due 2025	150	150
Debentures, 6⅞%, due 2026	67	67
Debentures, 7⅜%, due 2029	92	92
Notes, 7.20%, due 2031	575	575
Notes, 7.40%, due 2031	500	500
Discounts and Other	(41)	(45)
Total debt	3,916	4,337
Less current maturities	63	—
Total long-term debt	$3,853	$4,337

The Company has debt maturities of $63 million due in 2003, $0 million due in 2004 and 2005, $500 million due in 2006, $444 million due in 2007 and $2,950 million due in 2008 and thereafter. The Company had no outstanding commercial paper at December 31, 2002. The Company's commercial paper borrowings at December 31, 2001 had weighted average interest rates of approximately 3 percent. The fair value of debt outstanding, excluding commercial paper, as of December 31, 2002 and 2001 was $4,443 million and $3,727 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 on file with the Securities and Exchange Commission (SEC). Pursuant to such 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 February 2002, BRFC issued $350 million of 5.7% Notes due March 1, 2007 (February Notes), which were fully and unconditionally guaranteed by BR. The proceeds from the February Notes were used to retire commercial paper that was issued to finance the acquisition of certain assets from ATCO. The February Notes reduced the Company's amount available under its shelf registration statement on file with the SEC to $397 million. In May 2002, the Company restored its shelf registration statement to $1,500 million.

In June 2002, the Company retired a $100 million 8¼% Note. To retire the 8¼% Note, The Louisiana Land and Exploration Company, a subsidiary of BR, issued a $104 million promissory note at a per annum rate equal to the sum of Eurodollar rates plus 0.70 percent. The $104 million promissory note was retired on September 16, 2002. During 2002, the Company also retired $675 million of net commercial paper and had no commercial paper outstanding at December 31, 2002.

In June 2002, the Company commenced an offer to exchange outstanding 5.6% Notes due 2006, 6.5% Notes due 2011 and 7.4% Notes due 2031, which were issued by BRFC and fully and unconditionally guaranteed by BR, in a private offering in November 2001 (Private Notes), for a like principal amount of 5.6% Notes due 2006, 6.5% Notes due 2011 and 7.4% Notes due 2031 to be issued by BRFC, fully and unconditionally guaranteed by BR and registered under the Securities Act of 1933, as amended (Registered Notes). In July 2002, following the expiration of the exchange offer, the Company issued the Registered Notes. All of the Private Notes were exchanged for Registered Notes and the Private Notes were cancelled.

The Company had credit commitments in the form of revolving credit facilities (Revolvers) as of December 31, 2002. The Revolvers are comprised of agreements for $600 million, $400 million and Canadian $468 million (U.S. $296 million). The $600 million Revolver expires in December 2006 and the $400 million and Canadian $468 million Revolvers expire in December 2004 unless renewed by mutual consent. The Company has the option to convert any remaining balances on the $400 million and Canadian $468 million Revolvers to one year and five-year plus one day term notes, respectively. The Revolvers are available to cover 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, 2002, there are no amounts outstanding under the Revolvers and no outstanding commercial paper.

At the Company's option, interest on borrowings under the $600 million and $400 million Revolvers is based on the prime rate or Eurodollar rates. The other Revolver bears interest at rates based on prime or Eurodollar rates also at the Company's option, however, the lenders have the option to provide bankers' acceptances in lieu of Eurodollar rate loans. Under the covenants of the Revolvers, Company debt cannot exceed 60 percent of capitalization (as defined in the agreements).

Outstanding borrowings of $138 million and $127 million as of December 31, 2002 and 2001, respectively, on Company-owned 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.

8. Significant Concentrations

In 2002, 2001 and 2000, approximately 43 percent, 42 percent and 44 percent, respectively, of the Company's gas production was transported to direct sale customers through pipeline systems owned by two companies. The Company expects to continue to transport a substantial portion of its future gas production through these pipeline systems. See Note 11 for demand charges paid under firm and interruptible transportation capacity rights on interstate and intrastate pipeline systems.

9. Common Stock

The Company's Common Stock activity follows.

Number of Shares	Issued	Treasury	Outstanding
BALANCE AT DECEMBER 31, 1999	241,188,770	25,219,025	215,969,745
Adjustment of unexchanged Poco shares	(72)		(72)
Treasury shares purchased		3,505,000	(3,505,000)
Shares issued under compensation plans, net of forfeitures		(190,547)	190,547
Option exercises		(2,913,585)	2,913,585
BALANCE AT DECEMBER 31, 2000	241,188,698	25,619,893	215,568,805
Adjustment of unexchanged Poco shares	(10)		(10)
Treasury shares purchased		16,092,000	(16,092,000)
Shares issued under compensation plans, net of forfeitures		(264,011)	264,011
Option exercises		(1,052,187)	1,052,187
BALANCE AT DECEMBER 31, 2001	241,188,688	40,395,695	200,792,993
Shares issued under compensation plans, net of forfeitures		(242,216)	242,216
Option exercises		(404,048)	404,048
BALANCE AT DECEMBER 31, 2002	241,188,688	39,749,431	201,439,257

Stock Compensation Plans

The Company's 2002 Stock Incentive Plan (the 2002 Plan) succeeds its 1993 Stock Incentive Plan (the 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 whole or 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 7,500,000. At December 31, 2002, 7,465,425 shares were available for grant under the 2002 Plan.

In 1997, the Company adopted the 1997 Employee Stock Incentive Plan (the 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 2002 Plan. 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 5,000,000 shares. At December 31, 2002, 4,998,500 shares were available for grant under the 1997 Plan, of which up to 150,000 shares annually may be restricted stock.

The Company issued 257,025, 256,700 and 211,350 shares of restricted stock in 2002, 2001 and 2000, respectively, from the 1993, 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, 2002, 2001, and 2000 was approximately $35.73, $50.30 and $34.62, respectively. Related compensation expense of approximately $9 million, $7 million and $4 million was recognized for the years ended December 31, 2002, 2001 and 2000, respectively.

The Company's 2000 Stock Option Plan (the 2000 Plan) for Non-Employee Directors provides for the annual grant of a nonqualified option for 2,000 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 5,000 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 250,000. At December 31, 2002, 185,000 shares were available for grant under the 2000 Plan.

The Company's stock option activity follows.

	Options	Weighted Average Exercise Price
Balance, December 31, 1999	8,898,798	$ 37.80
Granted	1,432,925	34.55
Exercised	(2,913,585)	31.73
Cancelled	(837,044)	35.38
Balance, December 31, 2000	6,581,094	40.08
Granted	1,638,675	50.53
Exercised	(1,052,187)	35.81
Cancelled	(303,324)	47.00
Balance, December 31, 2001	6,864,258	42.93
Granted	1,008,850	35.64
Exercised	(404,048)	31.80
Cancelled	(304,846)	45.11
Balance, December 31, 2002	7,164,214	$ 42.44

The following table summarizes information related to stock options outstanding and exercisable at December 31, 2002.

Options Outstanding	Range of Exercise Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price
1,573,569	$ 23.32–$34.89	$ 31.85	4.5	1,364,971	$ 31.48
2,518,305	35.38– 44.00	39.05	6.1	1,570,255	41.20
3,072,340	45.25– 52.03	50.64	5.3	2,594,923	50.62
7,164,214	$ 23.32–$52.03	$ 42.44	5.4	5,530,149	$ 43.22

Exercisable stock options and weighted average exercise prices at December 31, 2001 and 2000 follow.

	Options Exercisable	Weighted Average Exercise Price
December 31, 2001	4,838,074	$ 41.41
December 31, 2000	5,348,994	$ 41.36

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 one-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 one-hundredth of a share of Series A Junior Participating Preferred Stock at a price of $200 per one 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 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.

On November 8, 1999 (effective November 18, 1999), the Company's Board of Directors designated one of the authorized preferred shares as Special Voting Stock. The Special Voting Stock was entitled to a number of votes equal to the number of outstanding Exchangeable Shares of Burlington Resources Canada Inc. (other than Exchangeable Shares held by the Company), on all matters presented to the stockholders of the Company. The one share of Special Voting Stock was issued to CIBC Mellon Trust Company, as trustee pursuant to the Voting and Exchange Trust Agreement among the Company, Burlington Resources Canada Inc. and CIBC Mellon Trust Company, for the benefit of the holders of the Exchangeable Shares of Burlington Resources Canada Inc. On September 14, 2001, all of the remaining outstanding Exchangeable Shares issued by the Company's subsidiary, Burlington Resources Canada Inc., in connection with the November 1999 acquisition of Poco Petroleums Ltd., were exchanged for the Company's Common Stock. The trustee returned the share of Special Voting Stock to the Company and by its terms it was deemed retired and cancelled and has been eliminated from the Company's capital.

10. 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. 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 provides a charitable award benefit to Directors who have served on the Board of Directors for at least two years. Upon the death of a Director, the Company will donate $1 million to one or more educational institutions or private foundations nominated by the Director. At December 31, 2002, a $7 million liability had been accrued for these benefits and is included in Other Liabilities and Deferred Credits on the Company's Consolidated Balance Sheet. In January 2003, the Board of Directors amended the program to provide that persons first elected to serve on the Board of Directors after January 2003 will not be eligible to participate in the program. Directors at the time of the amendment remain eligible for the program.

The Company has a discretionary defined contribution plan (401(k) Plan). 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 $11,000 in 2002. 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 $9 million, $8 million and $8 million to the 401(k) Plan for the years ended December 31, 2002, 2001 and 2000, respectively, to match eligible contributions by employees.

The following tables set forth the amounts recognized in the Consolidated Balance Sheet and Statement of Income.

	Pension Benefits		**Postretirement Benefits**	
Year Ended December 31,	**2002**	**2001**	**2002**	**2001**
	(In Millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$181	$160	$ 41	$ 32
Service cost	9	9	—	—
Interest cost	12	11	3	3
Amendments	—	—	—	—
Actuarial loss	2	1	1	9
Participant contributions	—	—	2	2
Acquisition	—	12	—	—
Benefits paid	(17)	(12)	(5)	(5)
Benefit obligation at end of year	187	181	42	41
Change in plan assets				
Fair value of plan assets at beginning of year	155	156	—	—
Actual return on plan assets	(12)	(4)	—	—
Employer contribution	12	—	3	3
Participant contributions	—	—	2	2
Acquisition	—	15	—	—
Benefits paid	(17)	(12)	(5)	(5)
Fair value of plan assets at end of year	138	155	—	—
Funded status	(49)	(26)	(42)	(41)
Unrecognized net actuarial loss	48	21	17	16
Unrecognized prior service cost	1	1	(6)	(6)
Net accrued benefit cost	—	(4)	(31)	(31)
Minimum pension liability	(13)	—	—	—
Intangible asset	3	—	—	—
Accumulated other comprehensive loss	10	—	—	—
Net accrued benefit cost	$ —	$ (4)	$ (31)	$ (31)

The market value of the Company's pension plan assets has declined as a result of market conditions and paid benefits, and at December 31, 2002, plan assets were lower than the accumulated benefit obligation. When the actuarial present value of the accumulated benefit obligation exceeds plan assets, a minimum pension liability adjustment is required. At December 31, 2002, the minimum pension liability adjustment was $13 million. For those plans where the accumulated benefit obligation and the projected benefit obligation exceeded the related fair value of the plans assets, the aggregate accumulated benefit obligation, projected benefit obligation and related assets for those plans were $137 million, $176 million and $124 million, respectively.

	Pension Benefits			**Postretirement Benefits**		
Year Ended December 31,	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
	(In Millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 9	$ 9	$ 9	$ —	$ —	$ —
Interest cost	12	11	11	3	3	3
Expected return on plan assets	(14)	(14)	(13)	—	—	—
Recognized net actuarial loss	1	—	—	—	—	—
Net benefit cost	$ 8	$ 6	$ 7	$ 3	$ 3	$ 3

	Pension Benefits			Postretirement Benefits		
Year Ended December 31,	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Weighted average assumptions						
Discount rate	6.75%	7.25%	7.50%	6.75%	7.25%	7.50%
Expected return on plan assets	8.50%	9.00%	9.00%	—	—	—
Rate of compensation increase	4.50%	5.00%	5.00%	—	—	—

A 10 percent annual rate of increase in the per capita cost of pre-age 65 covered health care benefits was assumed for 2003. The rate is assumed to decrease gradually to 5 percent for 2008 and remain at that level thereafter. A 12 percent annual rate of increase in the per capita cost of post-age 65 covered health care benefits was assumed to decrease gradually to 5 percent for 2010 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	$ 236	$ (203)
Effect on postretirement benefit obligation	$3,984	$(3,417)

11. Commitments and Contingent Liabilities

Demand Charges

The Company has entered into contracts which provide firm transportation capacity rights on interstate and intrastate pipeline systems. The remaining terms on these contracts range from 1 to 21 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. The Company paid $156 million, $128 million and $123 million of demand charges for the years ended December 31, 2002, 2001 and 2000, 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, 2002 follow.

	(In Millions)
2003	$140
2004	109
2005	93
2006	91
2007	75
Thereafter	355
Total	$863

Lease Obligations

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $29 million, $23 million and $24 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2002 follow.

	(In Millions)
2003	$ 44
2004	28
2005	25
2006	21
2007	19
Thereafter	112
Total	$249

Drilling Rig Commitments

During 1998, the Company entered into agreements to lease two deep water drilling rigs through 2004 with remaining commitments of $92 million. These commitments will be utilized by drilling exploration wells, partner participation or subletting to the extent possible. In addition, the Company has other drilling rig commitments of $6 million, $5 million and $1 million for 2003, 2004 and 2005, respectively.

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.

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 $68 million. In the event that the Company is found to have violated the civil False Claims Act, the Company could also 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. The Company has established a reserve that management believes to be adequate to provide for this potential liability based upon its evaluation of this matter. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings 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.

The Company has also been named as a defendant in the lawsuit styled *UNOCAL Netherlands B.V., et al v. Continental Netherlands Oil Company B.V., et al,* No. 98-854, filed in 1995 in the District Court in The Hague and currently pending in the Court of Appeal in The Hague, the Netherlands. Plaintiffs, who are working interest owners in the Q-1 Block in the North Sea, have alleged that the Company and other former working interest owners in the adjacent Logger Field in the L16a Block unlawfully trespassed or were otherwise unjustly enriched by producing part of the oil from the adjoining Q-1 Block. The plaintiffs claim that the defendants infringed upon plaintiffs' right to produce the minerals present in its license area and acted in violation of generally accepted standards by failing to inform plaintiffs of the overlap of the

Logger Field into the Q-1 Block. Plaintiffs seek damages of $97.5 million as of January 1, 1997, plus interest. For all relevant periods, the Company owned a 37.5 percent working interest in the Logger Field. Following a trial, the District Court in The Hague rendered a Judgment in favor of the defendants, including the Company, dismissing all claims. Plaintiffs thereafter appealed. On October 19, 2000, the Court of Appeal in The Hague issued an interim Judgment in favor of the plaintiffs and ordered that additional evidence be presented to the court relating to issues of both liability and damages. The Company and the other defendants are continuing to present evidence to the Court and vigorously assert defenses against these claims. The Company has also asserted claims of indemnity against two of the defendants from whom it had acquired a portion of its working interest share. If the Company is successful in enforcing the indemnities, its working interest share of any adverse judgment could be reduced to 15 percent for some of the periods covered by plaintiffs' lawsuit. The Company is unable at this time to reasonably predict the outcome, or, in the event of an unfavorable outcome, to reasonably estimate the possible loss or range of loss, if any, in this lawsuit. Accordingly, there has been no reserve established for this matter.

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 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 of these other lawsuits and proceedings cannot be predicted with certainty, management believes that the resolution of these other matters will not have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

The Company has established reserves for legal proceedings which are included in Other Liabilities and Deferred Credits on the Consolidated Balance Sheet. The establishment of a reserve involves a complex 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 of up to approximately $25 million to $30 million in excess of the amounts currently accrued. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued.

Guarantee

At December 31, 2002, the Company owns a 1.5 percent interest in a foreign entity that is accounted for at cost. The Company is the guarantor of approximately $14 million of the entity's total outstanding debt.

12. Supplemental Cash Flow Information

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

Year Ended December 31,	**2002**	**2001**	**2000**
		(In Millions)	
Interest paid—net of capitalized interest(1)	$ 260	$ 155	$ 195
Income taxes paid—net	$ 40	$ 136	$ 88

(1) Capitalized interest was $22 million, $9 million and $0 million for the years ended December 31, 2002, 2001 and 2000, respectively.

In December 2001, the Company purchased all of the outstanding shares of Hunter for $2,087 million, net of cash acquired. In conjunction with the acquisition, liabilities were assumed as follows.

	(In Millions)
Fair value of assets acquired	$3,297
Cash paid for the capital stock, net of cash acquired	2,087
Liabilities assumed	$1,210

At December 31, 2002, 2001 and 2000, capital expenditures included in Accounts Payable balance on the Consolidated Balance Sheet were $326 million, $298 million and $232 million, respectively.

13. Impairment of Oil and Gas Properties

In December 2001, primarily as a result of the Company's decision to exit the Gulf of Mexico Shelf and divest of certain other properties, the Company recognized a pretax impairment charge of $184 million primarily related to the impairment of oil and gas properties held for sale. The net book value of these properties at December 31, 2001 totaled approximately $338 million. These properties were sold during 2002.

14. Segment and Geographic Information

The Company's reportable segments are U.S., Canada and Other International. These segments are engaged principally in the exploration, development, production and marketing of oil, gas and NGLs. The accounting policies for the segments are the same as those described in Note 1. Intersegment sales were $17 million, $157 million and $85 million in 2002, 2001, 2000, respectively.

The following tables present information about reported segment operations.

	North America			
Year Ended December 31, 2002	**U.S.**	**Canada**	**Other International**	**Total**
	(In Millions)			
Revenues	$1,642	$1,161	$161	$2,964
Depreciation, depletion and amortization	350	382	78	810
Income (loss) before income taxes and cumulative effect of change in accounting principle	817	278	(99)	996
Capital expenditures	$ 491	$ 868	$435	$1,794

	North America			
Year Ended December 31, 2001	**U.S.**	**Canada**	**Other International**	**Total**
	(In Millions)			
Revenues	$2,260	$ 947	$212	$3,419
Depreciation, depletion and amortization	459	170	86	715
Impairment of oil and gas properties	184	—	—	184
Income before income taxes and cumulative effect of change in accounting principle	772	458	25	1,255
Capital expenditures	$ 653	$2,558	$217	$3,428

	North America			
Year Ended December 31, 2000	**U.S.**	**Canada**	**Other International**	**Total**
	(In Millions)			
Revenues	$2,280	$752	$186	$3,218
Depreciation, depletion and amortization	510	123	58	691
Income before income taxes and cumulative effect of change in accounting principle	1,026	313	36	1,375
Capital expenditures	$ 468	$336	$179	$ 983

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, total interest expense and other expense (income)—net have been excluded from segment operations.

Year Ended December 31,	**2002**	**2001**	**2000**
		(In Millions)	
Income before income taxes and cumulative effect of change in accounting principle for reportable segments	$996	$1,255	$1,375
Corporate expenses	184	170	184
Interest expense	274	190	197
Other expense (income)—net	(31)	(12)	27
Consolidated income before income taxes and cumulative effect of change in accounting principle	$569	$ 907	$ 967

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

Year Ended December 31,	**2002**	**2001**	**2000**
		(In Millions)	
Total capital expenditures for reportable segments	$1,794	$3,428	$ 983
Administrative capital expenditures	43	26	29
Consolidated capital expenditures	$1,837	$3,454	$1,012

15. Taxes Other Than Income Taxes

Taxes other than income taxes are as follow.

Year Ended December 31,	**2002**	**2001**	**2000**
		(In Millions)	
Severance taxes	$ 85	$ 137	$ 130
Ad valorem taxes	25	17	17
Payroll taxes and other	13	12	12
Total taxes other than income taxes	$ 123	$ 166	$ 159

16. Other Matters

Recent Accounting Pronouncements

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN No. 46), which addresses consolidation by business enterprises of variable interest entities. FIN No. 46 clarifies the application of Accounting Research Bulletin No. 51, *Consolidated Financial Statements,* to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN No. 46 applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. The Company does not expect to identify any variable interest entities that must be consolidated. In the event a variable interest entity is identified, the Company does not expect the requirements of FIN No. 46 to have a material impact on its financial condition or results of operations.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* (FIN No. 45). FIN No. 45 requires certain guarantees to be recorded at fair value, which is different from current practice to record a liability only when a loss is probable and reasonably estimable, as those terms are defined in FASB Statement No. 5, Accounting for Contingencies. FIN No. 45 also requires the Company to make significant new disclosures about guarantees. The disclosure requirements of FIN No. 45 are effective for the Company in the first quarter of fiscal year 2003. FIN No. 45's initial recognition and initial measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company's previous accounting for guarantees issued prior to the date of the initial application of FIN No. 45

will not be revised or restated to reflect the provisions of FIN No. 45. The Company does not expect the adoption of FIN No. 45 to have a material impact on its consolidated financial position, results of operations or cash flows.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, ''Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).'' SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred and establishes that fair value is the objective for initial measurement of the liability. The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. The Company adopted SFAS No. 146 on January 1, 2003, but at this time this statement has no effect on the Company's consolidated financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections*. SFAS No. 145, which is effective for fiscal years beginning after May 15, 2002, provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The Company adopted SFAS No. 145 on January 1, 2003, but at this time this statement has no effect on the Company's consolidated financial position or results of operations.

In June 2001, the FASB issued SFAS No. 143, *Accounting for 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 cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Based on current estimates, the Company expects to record a net-of-tax cumulative effect of change in accounting principle loss, in the first quarter of 2003, of approximately $59 million in accordance with the provisions of SFAS No. 143. There will be no impact on the Company's cash flows as a result of adopting SFAS No. 143.

REPORT OF MANAGEMENT

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

BR maintains a system of internal controls and a program of internal auditing that provides management with reasonable assurance that the Company's assets are protected and that its published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets regularly with BR's independent accountants, financial management, counsel and internal audit. To ensure complete independence, the independent accountants and internal audit personnel have full and free access to the Audit Committee to discuss the results of their audits, the adequacy of internal controls and the quality of financial reporting.

Our independent accountants provide an objective independent review by their audit of the Company's financial statements. Their audit is conducted in accordance with auditing standards generally accepted in the United States of America and includes a review of internal accounting controls to the extent deemed necessary for the purposes of their audit.

Steven J. Shapiro
Executive Vice President and
Chief Financial Officer

Joseph P. McCoy
Vice President, Controller and
Chief Accounting Officer

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, cash flows and stockholders' equity, present fairly, in all material respects, the financial position of Burlington Resources Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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 6 to the consolidated financial statements, on January 1, 2001, the Company changed its method of accounting for its derivative instruments and hedging activities in connection with its adoption of Statement of Financial Accounting Standards No. 133, ''Accounting for Derivative Instruments and Hedging Activities'', as amended.

February 19, 2003
Houston, Texas

PricewaterhouseCoopers LLP

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.

Year Ended December 31, 2002	North America U.S.	North America Canada	Other International	Total
			(In Millions)	
Property acquisition				
Unproved	$ 4	$ 13	$ —	$ 17
Proved	178	352	74	604
Exploration	35	126	40	201
Development				
Proved developed	165	279	32	476
Proved undeveloped	81	69	153	303
Total costs incurred	$463	$839	$299	$1,601

Year Ended December 31, 2001	North America U.S.	North America Canada(1)	Other International	Total
			(In Millions)	
Property acquisition				
Unproved	$ 14	$ 876	$ 4	$ 894
Proved	67	1,042	30	1,139
Exploration	99	76	48	223
Development				
Proved developed	292	251	10	553
Proved undeveloped	111	37	125	273
Total costs incurred	$583	$2,282	$217	$3,082

(1) The amounts exclude deferred taxes of $902 million related to the Hunter acquisition.

Year Ended December 31, 2000	North America U.S.	North America Canada	Other International	Total
			(In Millions)	
Property acquisition				
Unproved	$ 12	$ 21	$ 9	$ 42
Proved	6	14	29	49
Exploration	106	129	61	296
Development				
Proved developed	219	122	19	360
Proved undeveloped	69	30	61	160
Total costs incurred	$412	$316	$179	$907

The Company estimates that it will spend capital of approximately $589 million, $371 million and $241 million in 2003, 2004 and 2005, respectively, for the development of its proved undeveloped reserves.

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

Results of operations for oil, NGLs and gas producing activities, which exclude pipeline and processing activities, corporate general and administrative expenses, fixed-rate depreciation expense, and payroll and miscellaneous taxes, were as follow. Intersegment sales were $17 million, $157 million and $85 million in 2002, 2001 and 2000, respectively.

	North America		Other	
Year Ended December 31, 2002	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Revenues	$1,631	$1,162	$161	$2,954
Production costs	307	141	23	471
Exploration costs	116	121	49	286
Operating expenses	233	187	43	463
Depreciation, depletion and amortization	330	358	75	763
Income tax provision	224	151	10	385
Results of operations for oil and gas producing activities	$ 421	$ 204	$ (39)	$ 586

	North America		Other	
Year Ended December 31, 2001	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Revenues	$2,181	$946	$212	$3,339
Production costs	401	137	17	555
Exploration costs	167	52	39	258
Operating expenses	260	123	45	428
Depreciation, depletion and amortization	438	162	82	682
Impairment of oil and gas properties	184	—	—	184
Income tax provision (benefit)	265	234	(1)	498
Results of operations for oil and gas producing activities	$ 466	$238	$ 30	$ 734

	North America		Other	
Year Ended December 31, 2000	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Revenues	$2,226	$748	$186	$3,160
Production costs	372	122	20	514
Exploration costs	103	92	42	237
Operating expenses	276	89	30	395
Depreciation, depletion and amortization	487	118	54	659
Income tax provision	256	157	23	436
Results of operations for oil and gas producing activities	$ 732	$170	$ 17	$ 919

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BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

The following table reflects estimated quantities of proved oil, NGLs and gas 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, oil and NGLs that BR attributed to its net interests in oil and gas properties as of December 31, 2002. Miller and Lents, Ltd. reviewed the reserve estimates for the Company's U.S. and international interests (excluding Canada and Argentina) and Sproule Associates Limited reviewed the Company's interests in Canada and Argentina. 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.

	Oil (MMBbls)			
	North America		Other	
	U.S.	Canada	International	Worldwide
PROVED DEVELOPED AND UNDEVELOPED RESERVES				
December 31, 1999	216.2	51.9	44.1	312.2
Revisions of previous estimates	0.2	8.3	0.9	9.4
Extensions, discoveries and other additions	7.5	1.9	15.3	24.7
Production	(18.8)	(4.6)	(3.5)	(26.9)
Purchases of reserves in place	0.6	—	14.7	15.3
Sales of reserves in place	(1.5)	—	(1.5)	(3.0)
December 31, 2000	204.2	57.5	70.0	331.7
Revisions of previous estimates	(10.7)	(0.6)	0.4	(10.9)
Extensions, discoveries and other additions	66.7	2.9	2.5	72.1
Production	(16.1)	(4.3)	(2.7)	(23.1)
Purchases of reserves in place	0.4	1.2	0.8	2.4
Sales of reserves in place	(0.2)	(0.1)	—	(0.3)
December 31, 2001	244.3	56.6	71.0	371.9
Revisions of previous estimates	(2.0)	(1.4)	(1.6)	(5.0)
Extensions, discoveries and other additions	2.8	5.3	6.3	14.4
Production	(13.0)	(2.8)	(2.1)	(17.9)
Purchase of reserves in place	1.2	—	19.9	21.1
Sales of reserves in place	(46.1)	(43.3)	(7.2)	(96.6)
December 31, 2002	187.2	14.4	86.3	287.9
PROVED DEVELOPED RESERVES				
December 31, 1999	168.3	43.2	13.5	225.0
December 31, 2000	169.7	43.0	10.4	223.1
December 31, 2001	163.7	38.4	9.3	211.4
December 31, 2002	155.2	12.9	12.9	181.0

NGLs (MMBbls)			Gas (BCF)				
North America			North America				Total
U.S.	Canada	Worldwide	U.S.	Canada	Other International	Worldwide	Equivalent (BCFE)
212.6	51.2	263.8	4,935	1,211	803	6,949	10,404
(1.5)	(8.8)	(10.3)	(71)	(103)	(9)	(183)	(188)
24.1	5.7	29.8	489	192	8	689	1,016
(13.2)	(4.1)	(17.3)	(463)	(125)	(43)	(631)	(896)
0.2	0.1	0.3	5	18	—	23	117
—	(0.1)	(0.1)	(11)	(4)	(30)	(45)	(64)
222.2	44.0	266.2	4,884	1,189	729	6,802	10,389
5.8	(12.9)	(7.1)	107	(66)	(35)	6	(102)
9.6	4.8	14.4	253	165	58	476	995
(12.6)	(4.6)	(17.2)	(409)	(158)	(62)	(629)	(871)
2.7	16.4	19.1	59	1,007	207	1,273	1,402
—	—	—	(2)	(1)	—	(3)	(5)
227.7	47.7	275.4	4,892	2,136	897	7,925	11,808
9.8	14.7	24.5	(14)	(140)	(11)	(165)	(48)
15.7	9.2	24.9	350	341	85	776	1,012
(11.9)	(10.0)	(21.9)	(346)	(293)	(60)	(699)	(938)
—	0.2	0.2	153	268	—	421	549
(0.9)	(2.0)	(2.9)	(282)	(16)	(70)	(368)	(965)
240.4	59.8	300.2	4,753	2,296	841	7,890	11,418
168.3	41.6	209.9	3,907	983	289	5,179	7,788
177.6	35.5	213.1	3,903	960	251	5,114	7,731
175.5	39.3	214.8	3,771	1,758	384	5,913	8,470
179.2	53.1	232.3	3,617	1,836	263	5,716	8,196

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

A summary of the standardized measure of discounted future net cash flows relating to proved oil, NGLs and gas 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 oil, NGLs and gas reserves.

	North America		Other	
2002	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Future cash inflows	$ 24,879	$ 10,563	$ 3,861	$ 39,303
Less related future				
Production costs	5,543	1,634	1,072	8,249
Development costs	750	327	614	1,691
Income taxes	6,018	2,940	475	9,433
Future net cash flows	12,568	5,662	1,700	19,930
10% annual discount for estimated timing of cash flows	6,976	1,894	646	9,516
Standardized measure of discounted future net cash flows	$ 5,592	$ 3,768	$ 1,054	$ 10,414

	North America		Other	
2001	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Future cash inflows	$ 15,544	$ 6,206	$ 3,948	$ 25,698
Less related future				
Production costs	4,612	1,606	1,042	7,260
Development costs	752	654	741	2,147
Income taxes	2,701	1,433	621	4,755
Future net cash flows	7,479	2,513	1,544	11,536
10% annual discount for estimated timing of cash flows	3,971	920	645	5,536
Standardized measure of discounted future net cash flows	$ 3,508	$ 1,593	$ 899	$ 6,000

	North America		Other	
2000	**U.S.**	**Canada**	**International**	**Total**
			(In Millions)	
Future cash inflows	$ 52,400	$ 13,722	$ 3,895	$ 70,017
Less related future				
Production costs	7,732	1,394	926	10,052
Development costs	670	656	632	1,958
Income taxes	14,959	4,655	773	20,387
Future net cash flows	29,039	7,017	1,564	37,620
10% annual discount for estimated timing of cash flows	15,173	2,879	764	18,816
Standardized measure of discounted future net cash flows	$ 13,866	$ 4,138	$ 800	$ 18,804

BURLINGTON RESOURCES INC.
SUPPLEMENTARY FINANCIAL INFORMATION

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

	2002	2001	2000
		(In Millions)	
January 1	$ 6,000	$ 18,804	$ 6,293
Revisions of previous estimates			
Changes in prices and costs	6,744	(22,602)	18,827
Changes in quantities	(26)	60	(157)
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,235	483	2,613
Purchases of reserves in place	656	1,147	191
Sales of reserves in place	(1,215)	(15)	(46)
Accretion of discount	815	2,879	825
Sales of oil and gas, net of production costs	(2,483)	(2,784)	(2,646)
Net change in income taxes	(2,158)	7,836	(8,023)
Changes in rate of production and other	846	192	927
Net change	4,414	(12,804)	12,511
December 31	$ 10,414	$ 6,000	$18,804

Quarterly Financial Data—Unaudited

	2002				2001			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In Millions, Except per Share Amounts)							
Revenues(a)	$ 833	$ 651	$ 786	$ 694	$ 643	$ 679	$ 942	$1,155
Income Before Income Taxes and Cumulative Effect of change in Accounting Principle(b)	234	67	207	61	(137)	106	380	557
Income Before Cumulative Effect of Change in Accounting Principle	157	79	170	48	(79)	73	231	333
Net Income (Loss)(b)	157	79	170	48	(79)	73	231	336
Basic Earnings (Loss) per Common Share	0.78	0.39	0.84	0.24	(0.39)	0.36	1.10	1.57
Diluted Earnings (Loss) per Common Share	0.78	0.39	0.84	0.24	(0.39)	0.36	1.10	1.56
Cash Dividends Declared per Common Share	0.14	0.13	0.14	0.14	0.14	0.13	0.14	0.14
Common Stock Price Range								
High	43.67	39.65	45.34	41.60	39.75	44.19	51.95	53.63
Low	$34.76	$32.00	$36.90	$32.30	$32.75	$31.69	$37.55	$40.98

(a) Revenues for previously reported quarters reflect reclassifications made between revenues and costs and expenses during the fourth quarter of 2002. Revenues as reported in the Company's previously filed quarterly reports on Form 10-Q were as follow.

	2002			2001		
	3rd	2nd	1st	3rd	2nd	1st
	(In Millions, Except per Share Amounts)					
Revenues, as reported	$ 630	$ 769	$ 683	$ 666	$ 928	$1,152

(b) During the fourth quarter of 2001, the Company recognized a non-cash, pretax charge of $184 million primarily related to the impairment of oil and gas properties held for sale.

ITEM NINE

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

ITEMS TEN AND ELEVEN

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT AND EXECUTIVE COMPENSATION

A definitive proxy statement for the 2003 Annual Meeting of Stockholders (the Proxy Statement) of the Company will be filed no later than 120 days after the end of the fiscal year with the Securities and Exchange Commission. The information set forth therein under ''Election of Directors'' and ''Executive Compensation'' is incorporated herein by reference. 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.

ITEM TWELVE

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

The information required is set forth under the caption ''Stock Ownership of Management and Certain Other Holders'' in the Proxy Statement and is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

At December 31, 2002

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (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	5,656,724	42.10	7,650,425
Equity compensation plan not approved by security holders(1)	1,507,490	43.69	4,998,500
Total	7,164,214	42.44	12,648,925

(1) See Note 9 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

The information required is set forth under the caption ''Certain Relationships and Related Transactions'' in the Proxy Statement and is incorporated herein by reference.

ITEM FOURTEEN

CONTROLS AND PROCEDURES

Within 90 days prior to the filing date of this report, 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 its disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) to the Securities Exchange Act of 1934, as amended). Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer believe that the disclosure controls and procedures are effective with respect to timely communication 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.

There were no significant changes in the Company's internal controls or in other factors that could significantly affect internal controls subsequent to the date of the most recently completed evaluation, including any corrective actions with regards to significant deficiencies and material weaknesses.

PART IV

ITEM FIFTEEN

EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

Reports on Form 8-K

The Company filed no reports on Form 8-K during the last quarter of the fiscal year ended December 31, 2002.

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	March 12, 2003
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Executive Vice President and Chief Financial Officer	March 12, 2003
/s/ JOSEPH P. MCCOY Joseph P. McCoy	Vice President, Controller and Chief Accounting Officer	March 12, 2003
/s/ REUBEN V. ANDERSON Reuben V. Anderson	Director	March 12, 2003
/s/ LAIRD I. GRANT Laird I. Grant	Director	March 12, 2003
/s/ JOHN T. LAMACCHIA John T. LaMacchia	Director	March 12, 2003
/s/ JAMES F. MCDONALD James F. McDonald	Director	March 12, 2003
/s/ KENNETH W. ORCE Kenneth W. Orce	Director	March 12, 2003
/s/ DONALD M. ROBERTS Donald M. Roberts	Director	March 12, 2003
/s/ JOHN F. SCHWARZ John F. Schwarz	Director	March 12, 2003
/s/ WALTER SCOTT, JR. Walter Scott, Jr.	Director	March 12, 2003
/s/ WILLIAM E. WADE, JR. William E. Wade, Jr.	Director	March 12, 2003
/s/ ROBERT J. HARDING Robert J. Harding	Director	March 12, 2003

CERTIFICATIONS

I, Bobby S. Shackouls, certify that:

1. I have reviewed this annual report on Form 10-K of Burlington Resources Inc.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the ''Evaluation Date''); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

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

CERTIFICATIONS

I, Steven J. Shapiro, certify that:

1. I have reviewed this annual report on Form 10-K of Burlington Resources Inc.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the ''Evaluation Date''); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

Steven J. Shapiro
Executive Vice President and
Chief Financial Officer

CERTIFICATION ACCOMPANYING ANNUAL REPORT
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

(18 U.S.C. §1350)

The undersigned, Bobby S. Shackouls, Chairman of the Board, President and Chief Executive Officer of Burlington Resources Inc. (Company), hereby certifies that the Annual Report of the Company on Form 10-K for the year ended December 31, 2002 (the Report) (1) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 12, 2003

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

CERTIFICATION ACCOMPANYING ANNUAL REPORT
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

(18 U.S.C. §1350)

The undersigned, Steven J. Shapiro, Executive Vice President and Chief Financial Officer of Burlington Resources Inc. (Company), hereby certifies that the Annual Report of the Company on Form 10-K for the year ended December 31, 2002 (the Report) (1) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 12, 2003

Steven J. Shapiro
Executive Vice President and
Chief Financial Officer

BURLINGTON RESOURCES INC.

AMENDED EXHIBIT INDEX

The following exhibits are filed as part of this report.

Exhibit Number	Description	
3.1	Certificate of Incorporation of Burlington Resources Inc. as amended November 18, 1999	*
	Certificate of Elimination of Burlington Resources Inc. filed December 12, 2002 relating to the elimination of the Special Voting Stock	
3.2	By-Laws of Burlington Resources Inc. amended as of March 1, 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)	*
†10.1	The 1988 Burlington Resources Inc. Stock Option Incentive Plan as amended (Exhibit 10.4 to Form 8, filed March 1993)	*
†10.2	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 10.1 to Form 10-Q, filed April 2002)	*
†10.3	Burlington Resources Inc. Senior Executive Survivor Benefit Plan dated as of January 1, 1989 (Exhibit 10.11 to Form 8, filed February 1989)	*
†10.4	Burlington Resources Inc. Deferred Compensation Plan as amended and restated (Exhibit 10.4 to Form 10-K, filed February 1997)	*
†10.5	Burlington Resources Inc. Supplemental Benefits Plan as amended and restated (Exhibit 10.5 to Form 10-K, filed February 1997)	*
†10.6	Amended and Restated Employment Contract between the Company and Bobby S. Shackouls (Exhibit 10.29 to Form 10-Q, filed August 1999)	*
†10.7	Burlington Resources Inc. Compensation Plan for Non-Employee Directors as amended and restated (Exhibit 10.8 to Form 10-K, filed February 1997)	*
†10.8	Amended and Restated Burlington Resources Inc. Executive Change in Control Severance Plan (Exhibit 10.8 to Form 10-K, filed February 2001)	*
†10.9	Burlington Resources Inc. Retirement Income Plan for Directors (Exhibit 10.21 to Form 8, filed February 1991)	*

Exhibit Number	Description	
†10.10	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	
	Amendment No. 2 dated January 22, 2003 to Burlington Resources Inc. 1991 Director Charitable Award Plan	
10.11	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)	*
†10.12	Burlington Resources Inc. 1992 Stock Option Plan for Non-employee Directors (Exhibit 28.1 of Form S-8, No. 33-46518, filed March 1992)	*
†10.13	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)	*
†10.14	Burlington Resources Inc. 1992 Performance Share Unit Plan as amended and restated (Exhibit 10.17 to Form 10-K, filed February 1997)	*
†10.15	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)	*
†10.16	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 10.2 to Form 10-K, filed February 2001)	*
†10.17	Burlington Resources Inc. 1997 Performance Share Unit Plan (Exhibit 10.21 to Form 10-K, filed February 1997)	*
10.18	$400 million Short-term Revolving Credit Agreement, dated as of February 25, 1998, as Amended and Restated December 5, 2002, between Burlington Resources Inc. and JPMorgan Chase Bank, as agent	
10.19	$600 million Long-term Revolving Credit Agreement, dated as of February 25, 1998, as Amended and Restated December 7, 2001, between Burlington Resources Inc. and JPMorgan Chase Bank, as agent (Exhibit 10.19 to Form 10-K, filed February 2002)	*
	Amendment No. 1 dated April 25, 2002 to $600 million Long-term Revolving Credit Agreement (Exhibit 10.19 to Amendment No. 1 to Form S-4, filed June 2002)	*
	Amendment No. 2 dated December 5, 2002 to $600 million Long-term Revolving Credit Agreement	
†10.20	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)	*
†10.21	The LL&E Supplemental Excess Plan (Exhibit 10(j) to LL&E's Form 10-K, filed March 1993)	*
†10.22	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)	*
†10.23	Poco Petroleums Ltd. Incentive Stock Option Plan (Form S-8 No. 333-91247, filed November 18, 1999)	*
†10.24	Employee Savings Plan for Eligible Employees of Poco Petroleums Ltd. (Exhibit 4.4 to Form S-8 No. 333-95071, filed January 20, 2000)	*

Exhibit Number	Description	
†10.25	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)	*
†10.26	Burlington Resources Inc. 2000 Stock Option Plan for Non-Employee Directors (Exhibit 10.30 to Form 10-Q, filed August 2000)	*
†10.27	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)	*
†10.28	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 10.2 to Form 10-Q, filed April 2002)	*
10.29	Pre-Acquisition Agreement between Burlington Resources Inc. and Canadian Hunter Exploration Ltd. dated October 8, 2001 (Exhibit 99.2 to Form 8-K, filed October 2001)	*
10.30	Canadian Credit Agreement, dated as of March 31, 2000, as Amended and Restated December 5, 2002, among Burlington Resources Canada Ltd., Canadian Hunter Exploration Ltd., Burlington Resources Inc. and J.P. Morgan Chase Bank, Toronto Branch	
10.31	$350 million Bridge Revolving Credit Agreement, dated as of January 2, 2002, between Burlington Resources Inc. and JPMorgan Chase Bank, as agent	*
10.32	Burlington Resources Inc. 2002 Stock Incentive Plan (Exhibit A to Schedule 14A, filed March 15, 2002)	*
10.33	Burlington Resources Inc. 1997 Employee Stock Incentive Plan	
21.1	Subsidiaries of the Registrant	
23.1	Consent of Independent Accountants — 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	

*Exhibit incorporated herein by reference as indicated.

†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.