ENCANA™

# ANNUAL INFORMATION FORM

**February 25, 2004**

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## INTRODUCTORY INFORMATION

EnCana Corporation ("EnCana" or the "Corporation") was formed through the business combination (the "Merger"), on April 5, 2002, of Alberta Energy Company Ltd. ("AEC") and PanCanadian Energy Corporation ("PanCanadian"). The Merger was accomplished through an arrangement in respect of AEC under the *Business Corporations Act* (Alberta) and certain corporate changes for PanCanadian. Pursuant to the Merger, PanCanadian indirectly acquired all of the outstanding common shares of AEC in consideration for common shares issued by PanCanadian. PanCanadian's name was also changed to EnCana Corporation and its board of directors and senior management were reconstituted. Following completion of the Merger, AEC remained in existence, as an indirect wholly owned subsidiary of EnCana. On January 1, 2003, AEC and another subsidiary were amalgamated with EnCana. As a result of these transactions, the former PanCanadian and the former AEC continue as one corporation known as EnCana Corporation.

In this annual information form, unless otherwise specified or the context otherwise requires, reference to "EnCana" or to the "Corporation" includes reference to subsidiaries of and partnership interests held by EnCana Corporation and its subsidiaries. Any reference to "EnCana" or the "Corporation" for periods prior to the Merger are to EnCana's founding companies, PanCanadian and AEC, and their subsidiaries and partnership interests.

Unless otherwise indicated, all financial information included and incorporated by reference in this annual information form is determined using Canadian generally accepted accounting principles ("Canadian GAAP"), which differs from generally accepted accounting principles in the United States ("U.S. GAAP"). The notes to EnCana's audited consolidated financial statements contain a discussion of the principal differences between EnCana's financial results calculated under Canadian GAAP and under U.S. GAAP.

In accordance with Canadian GAAP, the consolidated financial statements of EnCana include the results of PanCanadian prior to the Merger and do not include any results related to AEC's operations prior to the Merger. Accordingly, unless otherwise indicated, all financial information contained in this annual information form for 2002 and prior periods does not reflect any results of AEC prior to the Merger. Unless otherwise indicated, other statistical information and operational results are presented on the same basis.

**Unless otherwise specified, all dollar amounts are expressed in United States dollars, all references to "dollars" or "$" are to United States dollars and all references to "C$" are to Canadian dollars.** For the financial years ended prior to December 31, 2003, all audited consolidated financial statements of EnCana were expressed in Canadian dollars. For purposes of expressing in United States dollars amounts that were previously expressed in Canadian dollars, the relevant amounts have been translated into United States dollars in the manner discussed in Note 2 to EnCana's audited consolidated financial statements for the year ended December 31, 2003. Capital expenditures budgeted for 2004 which are expected to be incurred in Canada have been translated into United States dollars using a rate of $0.73 United States dollars per one Canadian dollar.

## NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: capital investment levels and the allocation thereof, drilling plans and the timing and location thereof, production levels and the timing of achieving such levels, pipeline capacity, reserve estimates, the timing of completion of the Ekwan pipeline, the timing of completion of the Wild Goose Storage Facility expansion, the timing of completion of the Countess Storage Facility and the use of its capacity, the use of facilities related to the Hythe Gas Storage Facility and the timing thereof, the future impact of the Alberta Energy and Utilities Board's September 2003 shut-in order, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, the timing and completion of acquisitions, the timing and completion of the Starks Storage facility, net cash flows, geographical expansion, the amount and use of steam power generated by the Foster Creek cogeneration facility, recovery improvement in the Weyburn oil field, plans for seismic surveys, the netback price received by EnCana, projected increases in oil shipment volumes through the OCP pipeline and the forward-looking statements identified in the Corporation's Management's Discussion and Analysis for the year ended December 31, 2003, which is incorporated into this annual information form by reference.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other things contemplated by the forward-looking statements will not occur. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this annual information form include, but are not limited to: volatility of oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in EnCana's North American and foreign oil and natural gas and midstream operations, risks of war, hostilities, civil insurrection and instability affecting countries in which EnCana and its subsidiaries operate and terrorist threats, risks inherent in EnCana's and its subsidiaries' marketing operations, including credit risk, imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves, EnCana's and its subsidiaries' ability to replace and expand oil and natural gas reserves, EnCana's ability to generate sufficient cash flow from operations to meet its current and future obligations, EnCana's ability to access external sources of debt and equity capital, general economic and business conditions, EnCana's ability to enter into or renew leases, the timing and costs of gas storage facility, well and pipeline construction, EnCana's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, EnCana's and its subsidiaries' ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, risks associated with existing and potential future lawsuits and regulatory actions against EnCana and its subsidiaries, political and economic conditions in the countries in which EnCana and its subsidiaries operate including Ecuador, the risk that the anticipated synergies to be realized by the Merger will not be realized, difficulty in obtaining necessary regulatory approvals and such other risks and uncertainties described from time to time in EnCana's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive.

The forward-looking statements contained in this annual information form are made as of the date hereof and EnCana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this annual information form are expressly qualified by this cautionary statement.

## NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In 2003, the securities regulatory authorities in Canada (other than Quebec) adopted National Instrument 51-101 ("NI 51-101"), which imposes new oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. NI 51-101 and its companion policy specifically contemplate the granting of exemptions from some of the disclosure standards prescribed by NI 51-101 to companies that are active in the United States ("U.S.") capital markets, to permit the substitution of the standards required by the SEC in order to provide for comparability of oil and gas disclosure with that provided by U.S. and other international issuers. EnCana has obtained an exemption from Canadian securities regulatory authorities to permit it to provide disclosure in accordance with the relevant legal requirements of the SEC. Accordingly, the reserves data and other oil and gas information included or incorporated by reference in this annual information form is disclosed in accordance with U.S. disclosure requirements and practices. Such information, as well as the information that EnCana discloses in the future in reliance on the exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment.

EnCana has disclosed proved reserve quantities, using the standards contained in U.S. Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities" ("FAS 69").

Under U.S. disclosure standards, reserves and production information is disclosed on a net basis (after royalties). Unless otherwise indicated, the reserves and production information contained in this annual information form is shown on that basis.

In this annual information form, certain natural gas volumes have been converted to barrels of oil equivalent ("BOEs") on the basis of six thousand cubic feet ("Mcf") to one barrel ("bbl"). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

## CORPORATE STRUCTURE

### Name and Incorporation

As described under "Introductory Information", EnCana Corporation was formed through the Merger involving AEC and PanCanadian. EnCana is incorporated under the *Canada Business Corporations Act* ("CBCA").

AEC was incorporated on September 18, 1973 under *The Companies Act* (Alberta) and was continued under the *Business Corporations Act* (Alberta) on September 30, 1986.

PanCanadian was incorporated under the CBCA on June 26, 2001 in order to participate in the reorganization of Canadian Pacific Limited ("CPL") by way of a plan of arrangement whereby, effective October 1, 2001, CPL distributed to its common shareholders all of the shares of five public companies holding the assets of CPL's five primary operating subsidiaries, including PanCanadian. The holders of common shares of PanCanadian Petroleum Limited exchanged their shares for common shares of PanCanadian. At the conclusion of the CPL reorganization, PanCanadian Petroleum Limited became a wholly owned subsidiary of PanCanadian. PanCanadian Petroleum Limited and PanCanadian were amalgamated on January 1, 2002 and continued under the name "PanCanadian Energy Corporation". On completion of the Merger with AEC on April 5, 2002, PanCanadian's name was changed to "EnCana Corporation".

Prior to the CPL reorganization, PanCanadian Petroleum Limited was a public corporation, approximately 85 percent of which was held by CPL and 15 percent by the public. Originally established by CPL in 1958 as Canadian Pacific Oil and Gas Limited, PanCanadian Petroleum Limited began its operations using the fee title lands that the Government of Canada had transferred to CPL as part of CPL's building of the national railway across Canada. PanCanadian Petroleum Limited resulted from the amalgamation, under the laws of Canada, on December 31, 1971, of PanCanadian Petroleum Limited (incorporated as Central Leduc Oils Limited in 1947) and Canadian Pacific Oil and Gas Limited (incorporated in 1958). PanCanadian Petroleum Limited was continued under the CBCA on April 9, 1980.

The executive and registered office of EnCana is located at 1800, 855 – 2nd Street S.W., Calgary, Alberta, Canada T2P 2S5.

### Intercorporate Relationships

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of EnCana's principal subsidiaries and partnerships with total assets that exceed 10 percent of the total consolidated assets of EnCana or revenues that exceed 10 percent of the total consolidated revenues of EnCana as at and for the year ended December 31, 2003:

| Subsidiaries & Partnerships | Percentage Owned[(1)] | Jurisdiction of Incorporation, Continuance or Formation |
|---|---|---|
| EnCana Oil & Gas Partnership | 100 | Alberta |
| EnCana Midstream & Marketing | 100 | Alberta |
| EnCana West Ltd. | 100 | Alberta |
| Alenco Inc. | 100 | Delaware |
| EnCana Oil & Gas (USA) Inc. | 100 | Delaware |
| McMurry Oil Company | 100 | Wyoming |
| EnCana Marketing (USA) Inc. | 100 | Delaware |

Notes:

(1) Includes indirect ownership.

The above table does not include all of the subsidiaries and partnerships of EnCana. The assets and revenues of unnamed subsidiaries and partnerships in the aggregate did not exceed 20 percent of the total consolidated assets or total consolidated revenues of EnCana as at and for the year ended December 31, 2003.

## GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of the world's leading independent crude oil and natural gas exploration and production companies, based on landholdings and production at December 31, 2003. EnCana's key landholdings are in western Canada, the U.S. Rocky Mountains, Ecuador, the United Kingdom ("U.K.") central North Sea, offshore Canada's East Coast and the Gulf of Mexico. EnCana explores for, produces and markets natural gas, crude oil and natural gas liquids ("NGLs") in Canada and the U.S. EnCana is also engaged in exploration and production activities internationally including production from Ecuador and the U.K. central North Sea. EnCana has interests in midstream operations and assets, including natural gas storage, NGLs gathering and processing facilities, power plants and pipelines.

Upon completion of the Merger on April 5, 2002, EnCana's business was organized into four operating divisions: Onshore North America, Offshore & International Operations, Offshore & New Ventures Exploration, and Midstream & Marketing. During 2003, EnCana reorganized its operations, and now operates under two main divisions: (i) Upstream; and (ii) Midstream & Marketing. The following describes the significant transactions and events in the last three years in the businesses that are now conducted in those divisions.

### UPSTREAM

The Upstream division manages EnCana's exploration, development and production of natural gas, NGLs and crude oil and other related activities. The majority of EnCana's Upstream operations are located in Canada, the U.S., Ecuador and the U.K. central North Sea. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.

#### Canada

EnCana's Canadian Upstream operations are divided into two regions — Canadian Plains and Canadian Foothills & Frontier.

##### *Canadian Plains Region*

The Canadian Plains region of western Canada encompasses EnCana's natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation's crude oil projects in northeast Alberta, southern Alberta and Saskatchewan and coalbed methane ("CBM") projects in southern Alberta.

EnCana pursues natural gas in shallow and deep horizons and has had several discoveries over the last three years. EnCana is also involved in crude oil development projects including steam-assisted gravity drainage ("SAGD") operations at Foster Creek and Christina Lake in northeast Alberta. Commercial production commenced at Foster Creek in the fourth quarter of 2001. In 2003, the Corporation completed an expansion of the Foster Creek project to increase production beyond its original design capacity. At the end of 2003, EnCana completed the third phase of a planned seven phase carbon dioxide ("$CO_2$") miscible flood development at Weyburn, Saskatchewan. There are now 32 patterns, or well groupings, on stream out of a planned total of 75 patterns.

Exploration for CBM — natural gas derived from coal seams — over the last three years has led to the development of a number of CBM pilot projects located on the Palliser Block of southern Alberta. In the last half of 2003, EnCana expanded its CBM development by drilling approximately 200 wells on the Palliser Block.

In February 2003, EnCana sold a 10 percent interest in the Syncrude Joint Venture ("Syncrude") to Canadian Oil Sands Limited ("COS") for net cash consideration of approximately $690 million (C$1.0 billion). In July 2003, COS acquired EnCana's remaining 3.75 percent interest in Syncrude and an overriding royalty for net cash consideration of approximately $309 million (C$427 million), bringing the total net cash consideration from the sales to approximately $1.0 billion (C$1.5 billion). Both of these transactions are subject to post-closing adjustments.

In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources ("Petrovera") for approximately $285 million (C$374 million), before working capital adjustments. Petrovera is an Alberta partnership that produces heavy oil in western Canada. EnCana's share of Petrovera's net production averaged approximately 17,500 barrels per day of crude oil in 2003.

***Canadian Foothills & Frontier Region***

The Canadian Foothills & Frontier region includes EnCana's natural gas and crude oil exploration, development and production activities in northern Alberta and British Columbia. It also includes EnCana's exploration and development activities offshore the East Coast of Canada and in the Northwest Territories.

In 2003, EnCana completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in Cutbank Ridge, which is located in the foothills of British Columbia and Alberta. In September 2003, EnCana purchased a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 million (C$369 million). The Corporation had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales, resulting in the total landholding of approximately 500,000 net acres.

The Corporation has developed a large land position offshore the East Coast of Canada. Since the Deep Panuke natural gas discovery in 1999, EnCana has conducted an active exploration program, on its own and with partners. In February 2003, EnCana requested an adjournment of the regulatory approval process for offshore development at Deep Panuke. In December 2003, following the drilling of two successful exploration wells, Margaree and MarCoh, EnCana initiated work on a new plan for a potential offshore development at Deep Panuke.

**United States**

EnCana's interests in the U.S. are primarily located in the U.S. Rockies, north Texas, the Gulf of Mexico and Alaska. The development of the U.S. as a core area began in June 2000, when EnCana Oil & Gas (USA) Inc., an indirect wholly owned subsidiary of EnCana, acquired all of the shares of McMurry Oil Company and other private interests ("McMurry") for total consideration of approximately $778 million, including the assumption of debt. McMurry's principal producing properties are in the Jonah natural gas field located in the Green River Basin of southwest Wyoming.

In February 2001, EnCana Oil & Gas (USA) Inc., through a wholly owned subsidiary, acquired all of the shares of Ballard Petroleum LLC ("Ballard") for net cash consideration of approximately $220 million. Ballard's principal producing properties are in the Mamm Creek natural gas field located in the Piceance Basin of northwest Colorado.

As a result of the McMurry acquisition in June 2000, and a consolidation of some of EnCana's U.S. subsidiaries in December 2000, EnCana Oil & Gas (USA) Inc. indirectly owned all of the partnership interests in Jonah Gas Gathering Corporation, a Wyoming general partnership which owned the Jonah Gas Gathering System. In September 2001, EnCana Oil & Gas (USA) Inc.'s indirect interest in Jonah Gas Gathering Corporation was sold for proceeds of approximately $360 million.

In May 2002, wholly owned subsidiaries of EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from subsidiaries of El Paso Corporation ("El Paso") for approximately $275 million. The principal producing properties acquired from the El Paso subsidiaries are located in the Piceance Basin of northwest Colorado.

In July 2002, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from a subsidiary of The Williams Companies ("Williams") for approximately $350 million. The principal producing properties acquired from the Williams subsidiary are located in the Jonah natural gas field in southwest Wyoming.

In July 2003, EnCana Oil & Gas (USA) Inc. acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of approximately $91 million. This acquisition included interests in developed and undeveloped reserves, natural gas and associated NGLs production, and acreage located in north Texas.

In October 2003, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from Mesa Hydrocarbons LLC ("Mesa") for net cash consideration of approximately $100 million. The principal producing properties acquired from Mesa are in the Piceance Basin of northwest Colorado.

Also in October 2003, EnCana Energy Resources Inc., an indirect wholly owned subsidiary of EnCana, divested crude oil, natural gas and associated NGLs production, reserves, acreage and facilities located primarily in Montana for net cash consideration of approximately $85 million.

In the Gulf of Mexico, a subsidiary of EnCana participated in the Llano oil discovery in 1998. In October 2003, this non-operated interest in the Llano discovery was exchanged for additional interests in the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana.

EnCana has been increasing its landholdings in the Gulf of Mexico through lease sales, farm-ins, exchanges and acquisitions. Several exploration wells have been drilled over the last three years, including a 25 percent non-operated interest in a significant crude oil discovery at Tahiti in 2002. A deepwater discovery in the Gulf of Mexico at Sturgis was announced in October 2003 in which EnCana holds a 25 percent non-operated interest.

**Ecuador**

EnCana entered Ecuador in 1999 through the acquisition of Pacalta Resources Ltd. for total consideration of approximately $703 million, and is involved in crude oil exploration, development and production primarily in the Oriente Basin. In the fourth quarter of 2000, EnCana farmed-in to a 40 percent non-operated interest in Block 15 in the Oriente Basin. The Corporation further increased its activity in Ecuador in January 2003 through an acquisition of additional reserves and production from Vintage Petroleum, Inc. ("Vintage") for net cash consideration of approximately $116 million.

In November 2003, EnCana divested its interest in Block 27 in the Oriente Basin for net cash consideration of approximately $14 million.

EnCana is part of a consortium that completed construction of the Oleoducto de Crudos Pesados ("OCP") pipeline in Ecuador in August 2003. The pipeline was fully commissioned in November 2003 and has a capacity of 450,000 barrels per day. EnCana has an indirect 36.3 percent equity interest in OCP and a 15-year shipping commitment of approximately 108,000 barrels per day.

**United Kingdom**

In January 2000, EnCana completed the purchase of 13.5 percent and 20.2 percent interests in the Scott and Telford crude oil fields, respectively, in the U.K. central North Sea, for net cash consideration of approximately $177 million. In October 2003, through the Llano exchange referred to above, EnCana acquired an additional 14.0 percent interest in each of the Scott and Telford fields. The Corporation also assumed operatorship of the Scott and Telford fields. In early 2004, EnCana completed the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively, for net cash consideration of approximately $126 million. EnCana now holds 41.0 percent of the Scott field and 54.3 percent of the Telford field.

In the spring of 2001, the Corporation made a significant crude oil discovery in the U.K. central North Sea at Buzzard. In November 2003, the U.K. Department of Trade and Industry approved the development plan for Buzzard.

**International New Ventures Exploration**

EnCana invests a small portion (less than 5 percent) of its capital in high potential exploration beyond its core geographic areas, primarily in Africa, South America and the Middle East.

## MIDSTREAM & MARKETING

EnCana's midstream activities are primarily comprised of natural gas storage operations, NGLs processing and power generation operations.

EnCana continues to pursue expansions of its North American continental natural gas storage network with the expansion of the Wild Goose storage facility in northern California and the completion of the first phase of the Countess storage facility east of Calgary. The Wild Goose expansion is scheduled for completion in April 2004. The first phase of the new Countess facility came online in October 2003.

Also in October 2003, EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, announced that it is planning to build a new, high-deliverability natural gas storage facility in southwest Louisiana. This planned facility is known as the Starks project and the first phase of the facility is anticipated to be fully in-service by the third quarter of 2005.

In December 2001, EnCana sold its 100 percent interest in Alberta Oilsands Pipeline Ltd., owner of the Alberta Oilsands Pipelines System, for approximately $137 million (C$218 million).

In January 2003, EnCana completed the sale of its indirect 70 percent interest in the Cold Lake Pipeline System ("Cold Lake") for approximately $270 million (C$425 million). The Corporation has retained crude oil transportation capacity on the pipeline for its production through its existing long-term contracts. EnCana also completed the sale of its indirect 100 percent interest in the Express Pipeline System ("Express") in January 2003 for approximately $778 million (C$1.2 billion), which included the assumption of approximately $385 million (C$600 million) in debt by the purchaser. EnCana has retained crude oil transportation capacity on the system through its existing long-term contracts.

EnCana's marketing activities include the sale and delivery of produced product and the purchase of third party product, primarily for the optimization of midstream assets as well as the optimization of transportation arrangements not fully utilized for the Corporation's own production. EnCana's production of NGLs in western Canada is marketed through Kinetic Resources (LPG), an Alberta partnership in which EnCana has an indirect 75 percent interest, and Kinetic Resources (U.S.A.), a Michigan partnership in which EnCana has an indirect 75 percent interest (collectively, "Kinetic"). EnCana crude oil marketing supplies a limited number of third parties with marketing services for a fee.

All Houston-based merchant energy trading operations were discontinued following the Merger in 2002.

## NARRATIVE DESCRIPTION OF THE BUSINESS

EnCana's business is conducted in two main divisions: (i) Upstream; and (ii) Midstream & Marketing.

### UPSTREAM

The majority of EnCana's Upstream operations are located in Canada, the U.S., Ecuador and the U.K. central North Sea. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.

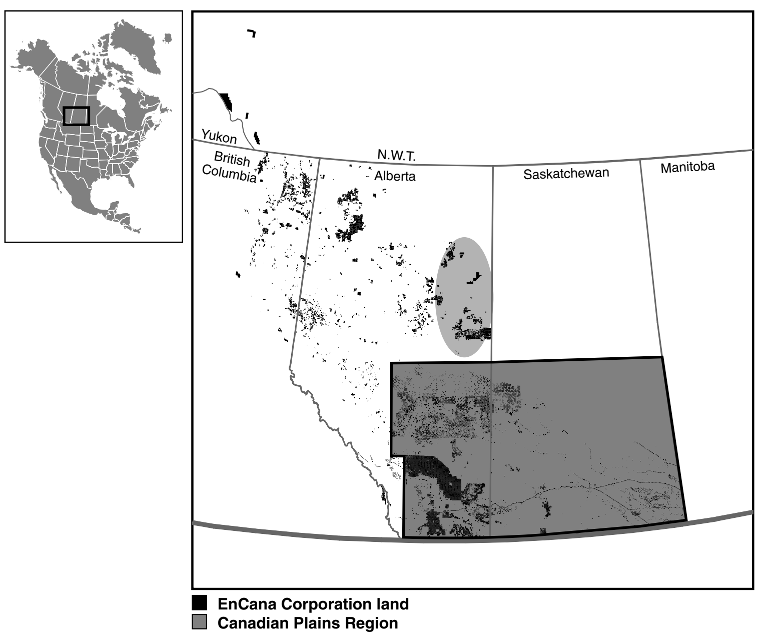
As at December 31, 2003, EnCana had net proved reserves of approximately 957 million barrels of crude oil and NGLs and 8.4 trillion cubic feet of natural gas, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 61 percent of total net proved reserves. See "Reserves and Other Oil and Gas Information".

*In the following discussion, comparative production information for 2002 is presented on the basis of combining the results of PanCanadian and AEC for the period prior to the Merger.*

#### Canada

Western Canada is EnCana's principal foundation, largely from its industry leading land position of approximately 25.1 million gross acres (approximately 21.5 million net acres, of which approximately 15.1 million net acres are undeveloped). The mineral rights on approximately one quarter of this land is acreage owned in fee title by EnCana, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights.

***Canadian Plains Region***




The Canadian Plains region encompasses EnCana's natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation's crude oil development projects, including thermal recovery projects at Foster Creek and Christina Lake using SAGD technology and a $CO_2$ miscible flood project at Weyburn. The region also includes EnCana's CBM projects in southern Alberta.

EnCana's 2004 capital investment in core programs for natural gas projects in the Canadian Plains region is budgeted to be approximately $860 million, with approximately $20 million directed to exploration and approximately $840 million to development. EnCana anticipates drilling approximately 3,450 gross natural gas wells (3,300 net wells) in this region in 2004. Capital investment in 2004 for crude oil projects is budgeted to be approximately $390 million, primarily directed towards development projects, including approximately $180 million for SAGD projects, and the drilling of approximately 570 gross oil wells (560 net wells).

The following describes EnCana's major producing areas or activities in the Canadian Plains region.

Suffield

At December 31, 2003, EnCana held an average 99 percent interest in the petroleum and natural gas rights to approximately 1.1 million gross acres (approximately 1.1 million net acres, of which approximately 223,000 net acres are undeveloped) in the productive Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeast Alberta.

The Suffield area is largely made up of the Suffield Block. Operations on the Suffield Block are carried out by EnCana in cooperation with the Canadian military according to guidelines established under agreements with the Government of Canada. At December 31, 2003, there were 6,514 gross producing shallow natural gas wells (6,497 net wells). There were also 66 gross natural gas wells (66 net wells) producing from deeper formations. EnCana's 2003 net production on the Suffield Block averaged 230 million cubic feet per day of dry, sweet natural gas (193 million cubic feet per day in 2002).

EnCana operates and holds a 100 percent interest in properties along the west side of the Suffield Block which produce heavy oil. At December 31, 2003, there were 861 gross producing oil wells (856 net wells), of which 551 gross wells (551 net wells) were horizontal wells. In 2003, EnCana's Suffield area net crude oil production averaged 26,945 barrels per day (22,834 barrels per day in 2002).

Brooks

At December 31, 2003, EnCana held an average 96 percent interest in the petroleum and natural gas rights to approximately 1.1 million gross acres (approximately 1.0 million net acres, of which approximately 134,000 net acres are undeveloped) in the Brooks area of southern Alberta, located east of Calgary. EnCana had interests in 7,886 gross producing natural gas wells (7,541 net wells) and 459 gross producing oil wells (449 net wells) at December 31, 2003. EnCana's net production in 2003 averaged 434 million cubic feet per day of natural gas and 15,295 barrels per day of crude oil and NGLs (429 million cubic feet per day of natural gas and 16,253 barrels per day of crude oil and NGLs in 2002).

Calgary

At December 31, 2003, EnCana held an average 94 percent interest in the petroleum and natural gas rights to approximately 1.3 million gross acres (approximately 1.2 million net acres, of which approximately 295,000 net acres are undeveloped) in the Calgary area. EnCana had interests in 2,573 gross producing natural gas wells (2,406 net wells) and 230 gross producing oil wells (183 net wells) at December 31, 2003. Average net production for 2003 in this area was 329 million cubic feet per day of natural gas and 7,342 barrels per day of crude oil and NGLs (345 million cubic feet per day of natural gas and 8,019 barrels per day of crude oil and NGLs in 2002).

Foster Creek

EnCana holds surface access rights for petroleum, natural gas and oilsands exploration, development and transportation from areas within the Primrose Block (Cold Lake Air Weapons Range) which were granted by the Government of Canada. EnCana has acquired, and has certain rights to acquire, oilsands leases wherever deposits of crude oil bitumen are identified within the areas for which petroleum and natural gas lease rights are held. EnCana is currently operating a 100 percent owned thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology. In 2003, EnCana's net production averaged 21,823 barrels per day of crude oil (13,026 barrels per day in 2002). Construction of the Phase I Expansion of the Foster Creek project was completed in the third quarter of 2003. The Phase I Expansion is designed to increase 2004 net production to an expected average rate of approximately 28,000 barrels per day of crude oil.

In 2003, EnCana completed the construction and commenced commercial operation of an 80 megawatt, natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. The facility reached its full capacity of 80 megawatts in the fourth quarter of 2003. The steam generated by the facility is being used within the SAGD operation and the power generated is being sold into the Alberta Power Pool grid.

Christina Lake

EnCana completed construction of a 100 percent owned thermal crude oil recovery pilot project at Christina Lake using SAGD technology, and commenced production at the end of the third quarter of 2002. Net production was approximately 3,806 barrels of crude oil per day in 2003 (307 barrels per day in 2002).

Thermal Recovery Research and Development

EnCana continues to research and develop technologies to increase recovery and decrease the costs of extracting crude oil bitumen from oilsands.

One focus area is to reduce the reliance on steam in crude oil bitumen production. To this end, EnCana is piloting two technologies using solvents as part of the extraction process. The Solvent Aided Process ("SAP") mixes a small amount of solvent with steam to enhance recovery, while the Vapex process uses solvent in place of steam. After piloting SAP at Senlac, Saskatchewan in 2002, EnCana began construction of a pilot operation at Christina Lake in 2003. SAP testing at Christina Lake is expected to begin in the second quarter of 2004. The Vapex pilot commenced testing at Foster Creek in 2002, with additional research planned for 2004. Another focus area is artificial lift where EnCana is pursuing pump designs that are anticipated to enable the Corporation to implement low pressure SAGD and decrease facility capital costs. In 2003, EnCana successfully field-tested certain downhole pumps under existing SAGD operating conditions, allowing for further development of technology.

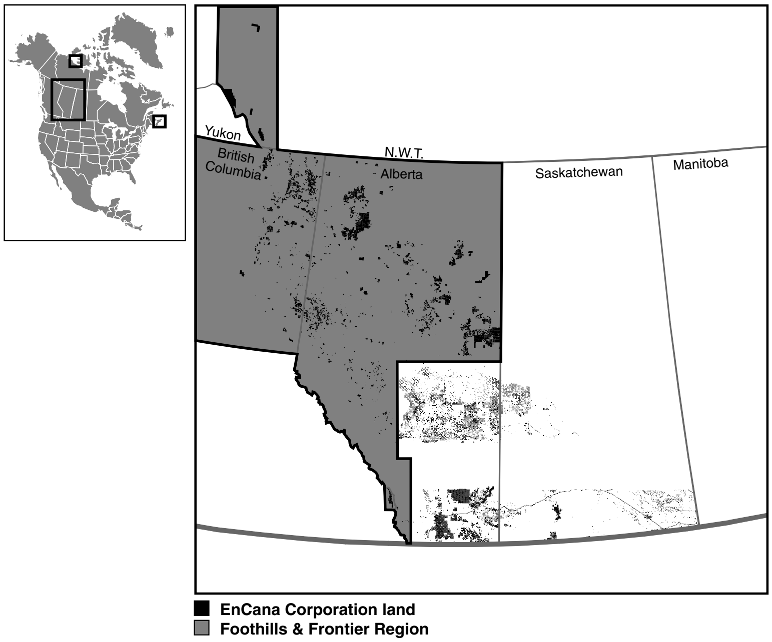
Weyburn

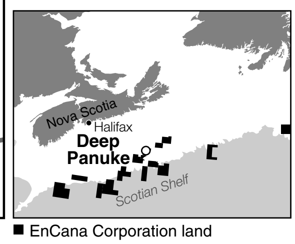
EnCana has a 62 percent working interest (50 percent economic interest) in the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area with a $CO_2$ miscible flood project. EnCana's net production from Weyburn in 2003 averaged 10,846 barrels of crude oil per day (10,549 barrels per day in 2002).

Coalbed Methane

EnCana is expanding CBM development on its 100 percent owned fee title lands in southern Alberta. During 2003, the Corporation drilled approximately 270 wells, increasing production from the commercial demonstration project to approximately 10 million cubic feet per day. In 2004, EnCana plans to drill approximately 300 wells, which is expected to increase CBM production to approximately 30 million cubic feet per day by year end.

***Canadian Foothills & Frontier Region***




The major producing areas of the Canadian Foothills & Frontier region include Greater Sierra in northeast British Columbia, Sexsmith/Hythe/Saddle Hills in northwest Alberta, and the Primrose Block and Pelican Lake in northeast Alberta. The region also encompasses EnCana's recent Cutbank Ridge land acquisition spanning the British Columbia-Alberta border, as well as exploration and development activities offshore the East Coast of Canada and in the Northwest Territories.

EnCana's 2004 capital investment in core programs for natural gas projects in the Canadian Foothills & Frontier region is budgeted to be approximately $990 million, with approximately $110 million directed to exploration and approximately $880 million to development. EnCana plans to drill approximately 620 gross natural gas wells (590 net wells) and approximately 100 gross crude oil wells (95 net wells) in this region in 2004. Capital investment for crude oil projects is budgeted to be approximately $100 million, primarily directed towards development projects.

Greater Sierra

In the Greater Sierra area of northeast British Columbia, at December 31, 2003, EnCana held an average 86 percent interest in the petroleum and natural gas rights to approximately 3.2 million gross acres (approximately 2.8 million net acres, of which approximately 2.4 million net acres are undeveloped). EnCana held an average 96 percent interest in 13 production facilities in the area that were capable of processing approximately 320 million cubic feet per day of natural gas as at December 31, 2003. EnCana is currently in the process of constructing the $43 million Ekwan pipeline in northeast British Columbia which will transport natural gas to Alberta. The pipeline will extend approximately 80 kilometres with a capacity of approximately 400 million cubic feet per day. Completion of the pipeline is expected in the second quarter of 2004. EnCana had interests in 503 gross producing natural gas wells (440 net wells) at December 31, 2003. EnCana's net production in 2003 averaged 143 million cubic feet per day of natural gas and 607 barrels per day of NGLs (110 million cubic feet per day of natural gas and 524 barrels per day of NGLs in 2002).

Sexsmith/Hythe/Saddle Hills

In the Sexsmith/Hythe/Saddle Hills area in northwest Alberta, at December 31, 2003, EnCana held an average 80 percent interest in the petroleum and natural gas rights to approximately 529,000 gross acres (approximately 423,000 net acres, of which approximately 248,000 net acres are undeveloped). EnCana had interests in 296 gross natural gas wells (239 net wells) and 100 gross oil wells (67 net wells) that were producing at December 31, 2003. EnCana's net production in 2003 averaged 114 million cubic feet per day of natural gas and 2,990 barrels per day of crude oil and NGLs (99 million cubic feet per day of natural gas and 3,113 barrels per day of crude oil and NGLs in 2002).

EnCana operates and has a 62 percent interest in a 210 million cubic feet per day sour natural gas and liquids processing plant and an 85 percent interest in a 50 million cubic feet per day sweet natural gas plant in the Sexsmith area. EnCana owns 100 percent of and operates the Hythe sour natural gas plant, which has a capacity of approximately 170 million cubic feet per day. The Hythe and Sexsmith sour natural gas plants are interconnected by pipeline to provide greater operating efficiencies. EnCana also owns and operates a 240-kilometre natural gas gathering system in the area.

Primrose Block

At December 31, 2003, EnCana held an average 97 percent interest in the petroleum and natural gas rights to approximately 868,000 gross acres (approximately 842,000 net acres, of which approximately 541,000 net acres are undeveloped) on the Primrose Block in northeast Alberta. At December 31, 2003, EnCana had interests in 533 gross natural gas wells (511 net wells) that were producing. In 2003, EnCana's net production from Primrose averaged 174 million cubic feet per day of natural gas (187 million cubic feet per day in 2002), the majority of which is processed through 100 percent controlled and operated compression facilities. EnCana's 2003 production volumes, primarily from the Primrose Block, were affected by an Alberta Energy and Utilities Board decision, in September 2003, to shut-in natural gas production that may put at risk the recovery of bitumen resources in the area. The decision resulted in EnCana's annualized natural gas production in the region declining by approximately three million cubic feet per day. The future impact of this decision is not known at this time but EnCana does not expect it to be material.

Pelican Lake

At December 31, 2003, EnCana held a 100 percent interest in approximately 224,000 gross acres (approximately 224,000 net acres, of which approximately 167,000 net acres are undeveloped) of crude oil bitumen rights at Pelican Lake in north-central Alberta. EnCana also holds a 38 percent interest in a 110-kilometre, 20-inch diameter crude oil pipeline which connects the Pelican Lake area to a major pipeline that transports crude oil from northern Alberta to crude oil markets. EnCana's net production in 2003 from this area averaged 15,944 barrels per day of crude oil (13,739 barrels per day in 2002) from interests in 460 gross oil wells (453 net wells) that were producing at December 31, 2003.

Cutbank Ridge

In September 2003, EnCana completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in the Canadian Rocky Mountain foothills. The lands in this new resource play — called Cutbank Ridge — are located approximately 50 kilometres southwest of Dawson Creek, British Columbia. In September 2003, EnCana purchased a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 million (C$369 million). The Corporation had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales, resulting in the total landholding of approximately 500,000 net acres in the area. In 2003, EnCana drilled 19 net natural gas wells at Cutbank Ridge which produced approximately 14 million cubic feet per day of natural gas in December 2003. In 2004, EnCana plans to drill approximately 40 net natural gas wells at Cutbank Ridge.

East Coast of Canada

Offshore Nova Scotia on the East Coast of Canada, EnCana has a 100 percent working interest in the Deep Panuke natural gas discovery approximately 250 kilometres off the coast of Nova Scotia in approximately 40 metres of water. Infrastructure in this relatively under-explored basin will require expansion, the cost of which must be borne at least partly by the Deep Panuke project. In February 2003, EnCana requested an adjournment of the regulatory approval process in order to pursue further steps to improve the project's economics. In December 2003, following the drilling of two successful exploration wells, Margaree (100 percent operated interest) and MarCoh (24.5 percent operated interest), EnCana initiated work on a new plan for a potential offshore development at Deep Panuke.

In 2002, the Corporation participated in the drilling of the Annapolis well offshore Nova Scotia, which encountered approximately 30 metres of net natural gas pay over several zones. Further plans to assess the potential of this discovery are under development. EnCana has a 26 percent non-operated interest in the discovery.

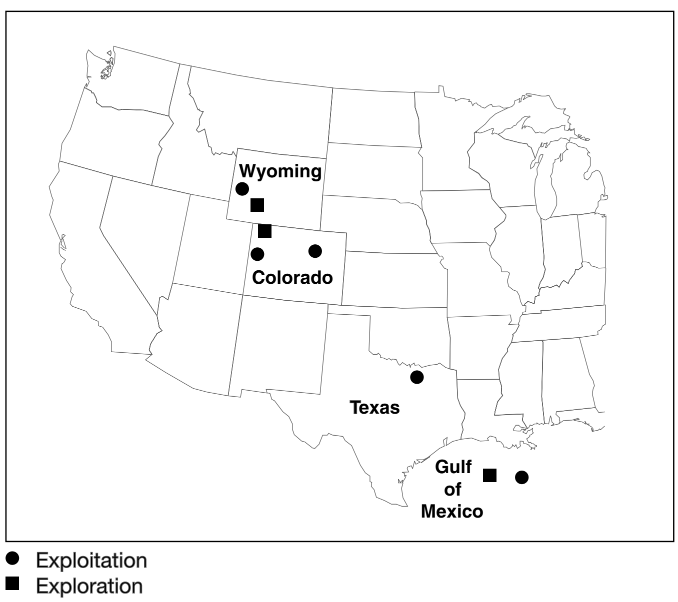
At December 31, 2003, EnCana held an interest in approximately 4.4 million gross acres (approximately 3.0 million net acres) of exploration lands offshore Nova Scotia. The Corporation also held an interest in approximately 4.3 million gross acres (approximately 2.8 million net acres) of exploration lands located offshore Newfoundland and Labrador at December 31, 2003. EnCana operates 19 of its 25 exploration licenses in these areas and has an average working interest of approximately 66 percent.

Northwest Territories

EnCana has an approximate 37 percent interest in two exploration blocks comprising approximately 529,000 gross acres (approximately 198,000 net acres) in the Mackenzie Delta region of Canada's Northwest Territories. The Corporation is planning to drill one exploration well in the first half of 2004.

The Corporation has an approximate 60 percent working interest in two exploration blocks comprising approximately 388,000 gross acres (approximately 233,000 net acres) in the Norman Wells area of the Northwest Territories. EnCana is planning to drill one exploration well in the first half of 2004.

**United States**




EnCana's operations in the U.S. Rockies area are currently focused on exploiting deep, tight, long-life natural gas formations primarily in the Jonah sweet natural gas field located in the Green River Basin of southwest Wyoming and the Mamm Creek natural gas field located in the Piceance Basin of northwest Colorado. EnCana's U.S. operations also include interests in north Texas, the Gulf of Mexico and Alaska, as well as various natural gas gathering and processing assets.

EnCana's 2004 capital investment in core programs for natural gas projects in the U.S. is budgeted at approximately $820 million, with approximately $90 million directed to exploration and approximately $730 million to development, and includes the drilling of approximately 535 gross natural gas wells (500 net wells). Capital investment for crude oil projects is budgeted to be approximately $100 million, primarily directed to exploration projects.

Jonah

At Jonah in southwest Wyoming, EnCana held an average 75 percent interest in the petroleum and natural gas rights to approximately 77,000 gross acres (approximately 58,000 net acres, of which approximately 48,000 net acres are undeveloped) and had interests in 327 gross natural gas wells (287 net wells) that were producing at December 31, 2003. EnCana's net production in 2003 averaged 374 million cubic feet per day of natural gas and 3,348 barrels per day of NGLs (275 million cubic feet per day of natural gas and 2,788 barrels per day of NGLs in 2002).

Mamm Creek

At Mamm Creek in northwest Colorado, EnCana held an average 96 percent interest in the petroleum and natural gas rights to approximately 176,000 gross acres (approximately 168,000 net acres, of which approximately 113,000 net acres are undeveloped) and had interests in 601 gross natural gas wells (591 net wells) that were producing at December 31, 2003. EnCana's net production in 2003 averaged 125 million cubic feet per day of natural gas and 1,013 barrels per day of NGLs (56 million cubic feet per day of natural gas and 389 barrels per day of NGLs in 2002).

In October 2003, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from Mesa for net cash consideration of approximately $100 million. The principal producing properties acquired from Mesa are in the Piceance Basin of northwest Colorado.

North Texas

In north Texas, EnCana held an average 77 percent interest in the petroleum and natural gas rights to approximately 95,000 gross acres (approximately 73,000 net acres, of which approximately 59,000 net acres are undeveloped) and had interests in 163 gross natural gas wells (159 net wells) that were producing at December 31, 2003. EnCana's net production in 2003 averaged seven million cubic feet per day of natural gas and 218 barrels per day of NGLs.

In July 2003, EnCana Oil & Gas (USA) Inc. acquired the common shares of Savannah for net cash consideration of approximately $91 million. This acquisition included interests in developed and undeveloped reserves, natural gas and associated NGLs production, and acreage located in north Texas.

Gulf of Mexico

EnCana owns a 25 percent non-operated interest in the Tahiti crude oil discovery, located in the deep water Green Canyon Block 640. Four appraisal wells were drilled in the first half of 2003 to evaluate this discovery.

In October 2003, a subsidiary of EnCana exchanged its 22.5 percent non-operated interest in the Llano crude oil discovery in the Gulf of Mexico for additional interests in the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana. Also in October 2003, a deepwater discovery in the Gulf of Mexico at Sturgis was announced in which EnCana holds a 25 percent non-operated interest.

EnCana has working interest acreage in over 262 exploration blocks comprising approximately 1.5 million gross acres (approximately 663,000 net acres) in the Gulf of Mexico, with options to add approximately 15 additional blocks. Such options were acquired through large regional farm-ins and the Corporation's ongoing land acquisition program.

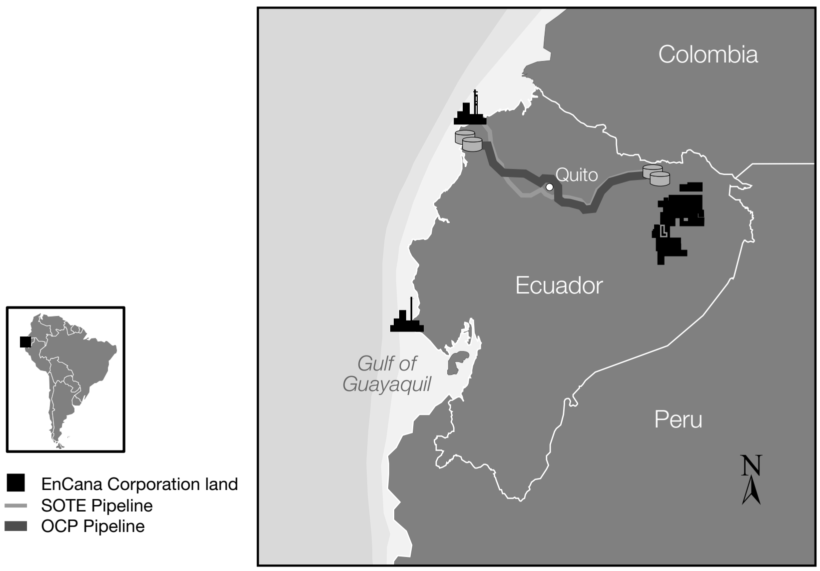
Alaska

EnCana has working interests in approximately 1.8 million gross acres (approximately 802,000 net acres) of exploration lands in both offshore and onshore Alaska.

Other

EnCana owns and operates various gas gathering and NGLs processing facilities in Colorado. Near Fort Lupton, Colorado, the gathering facilities include field compression and over 1,000 kilometres of pipelines, and the processing plant has a capacity of approximately 90 million cubic feet per day. Near Rifle, Colorado, EnCana's gathering facilities have a capacity of approximately 240 million cubic feet per day and include over 645 kilometres of pipelines. Near Rangely, Colorado, the Corporation's gathering facilities include field compression and over 1,600 kilometres of pipelines. The processing plant has a capacity of approximately 60 million cubic feet per day.

**Ecuador**




In Ecuador, EnCana is the largest private sector crude oil producer. An indirect, wholly owned subsidiary of EnCana owns one concession in the Oriente Basin, known as the Tarapoa Block. The Corporation has a 100 percent working interest in this concession, which is operated under a participation contract permitting the subsidiary to explore for and produce crude oil at its sole risk and expense during the contract term. The participation contract for the Tarapoa Block has a primary term through to August 1, 2015.

EnCana's 2004 capital investment in core programs for crude oil projects in Ecuador is budgeted to be approximately $180 million, directed primarily to development projects, and includes the drilling of approximately 45 gross crude oil wells (25 net wells).

In the fourth quarter of 2000, EnCana farmed-in to a 40 percent non-operated interest in Block 15 in the Oriente Basin. The concession is operated under a participation contract which has primary terms through to July 2012 for base area production and July 2019 for production resulting from additional exploration.

In January 2003, EnCana acquired majority operating interest in Blocks 14, 17 and Shiripuno, in the Oriente Basin, from Vintage for net cash consideration of approximately $116 million. The acquisition included both developed and undeveloped reserves producing approximately 4,000 barrels of crude oil per day from Blocks 14 and 17. The production contracts for Blocks 14 and 17 expire in July, 2012 and December, 2018, respectively.

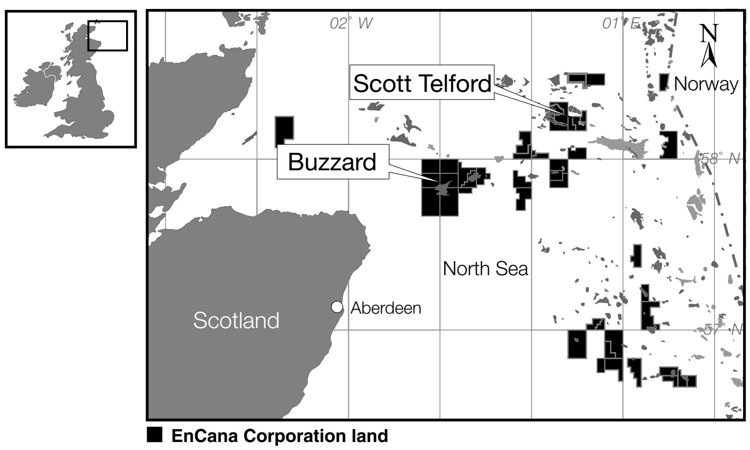
At December 31, 2003, EnCana held an average 64 percent interest in the petroleum rights to approximately 1.4 million gross acres (approximately 891,000 net acres, of which approximately 811,000 net acres are undeveloped) in Ecuador. At December 31, 2003, 172 gross crude oil wells (127 net wells) were producing. EnCana's net crude oil production in 2003 was 51,089 barrels per day (36,521 barrels per day in 2002).

With the commissioning of the OCP pipeline completed in November 2003, the Corporation expects 2004 net production from Ecuador to range between 68,000 and 74,000 barrels per day of crude oil.

OCP Pipeline

EnCana is part of a consortium that completed construction of the OCP pipeline in August 2003. The pipeline was fully commissioned in November 2003. OCP is a 500-kilometre pipeline with a capacity of approximately 450,000 barrels per day that runs from the crude oil producing area of Ecuador to the Pacific Coast. Pursuant to the terms of the agreement with the Government of Ecuador, the OCP pipeline will be transferred to the Government of Ecuador, without cost, after a 20-year operating period. EnCana has an indirect 36.3 percent equity interest in OCP, and a 15-year shipping commitment of approximately 108,000 barrels per day.

**United Kingdom**




EnCana has a working interest in the Scott and Telford crude oil fields located in the U.K. central North Sea, 190 kilometres northeast of Aberdeen, Scotland. EnCana's working interest is 41.0 percent at Scott and 54.3 percent at Telford. In October 2003, EnCana assumed operatorship of the Scott and Telford fields.

Crude oil produced from both fields is processed at the production platform and transported via pipeline through the non-operated Forties pipeline system. The Corporation acquired its initial interests in these fields (13.5 percent in Scott and 20.2 percent in Telford) in January 2000. In October 2003, EnCana increased its ownership by 14 percent in both the Scott and Telford fields through an exchange involving a subsidiary's interest in the Llano crude oil discovery in the Gulf of Mexico. In early 2004, EnCana further increased its ownership through the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively.

EnCana's 2004 capital investment in the U.K. is budgeted to be approximately $360 million, directed primarily to development projects, and includes the drilling of approximately 15 gross crude oil wells (7 net wells).

At December 31, 2003, there were 24 gross crude oil wells (7 net wells) producing. EnCana's net sales of crude oil and NGLs averaged 10,128 barrels per day in 2003 (10,528 barrels per day in 2002). In 2003, average net natural gas sales were approximately 13 million cubic feet per day (approximately 10 million cubic feet per day in 2002).

Development work on the Buzzard discovery in the central North Sea is continuing with initial production anticipated in late 2006. In November 2003, the U.K. Department of Trade and Industry approved the development plan for Buzzard. EnCana is the operator and holds an approximate 43.2 percent interest in the Buzzard field.

At December 31, 2003, EnCana had interests in 63 exploration blocks in the U.K. central North Sea and held a total land position of approximately 1.9 million gross acres (approximately 756,000 net acres, of which approximately 744,000 net acres are undeveloped). Interests range from 8.2 percent to 100 percent. Included in these interests are interests in eight deepwater frontier blocks in the Atlantic Margin west of Great Britain, comprising approximately 241,000 gross acres (approximately 45,000 net acres).

**International New Ventures Exploration**

Central and West Africa

EnCana has established onshore exploration operations in Chad, based out of the Corporation's office in N'Djamena. EnCana has a 50 percent working interest in Permit H comprising approximately 108.5 million gross acres (approximately 54.3 million net acres). EnCana completed the drilling of one exploratory well in February 2004, and activity over the remainder of the year is expected to include seismic surveys and the drilling of an additional two to three exploratory wells.

In 2003, EnCana participated in the drilling of one well in the Gulf of Guinea, offshore Ghana. EnCana has a 40 percent working interest in the Keta Block, comprising approximately 3.7 million gross acres (approximately 1.5 million net acres).

Brazil

EnCana has a 67 percent working interest in Block BM-C-7 comprising approximately 161,000 gross acres (approximately 108,000 net acres) offshore Brazil in the Campos Basin. In 2004, the Corporation plans to drill one exploration well on this block.

Middle East

During 2003, EnCana completed the testing of an exploration well on Block 2 in the State of Qatar. EnCana's share of Block 2 increased to 100 percent during the year. This block encompasses most of the onshore lands in Qatar and covers approximately 2.8 million acres. The Corporation is currently evaluating entry into the second exploration phase on Block 2.

In 2003, EnCana drilled one well on its acreage on Block 47 in the Republic of Yemen. The Corporation has a 53 percent working interest in Block 47 (approximately 1.9 million gross acres and approximately 987,000 net acres). EnCana and its partners relinquished the permit for Block 60 in December 2003.

In 2003, the Corporation initiated exploration activities in the Sultanate of Oman. EnCana has a 100 percent working interest in onshore Blocks 3 and 4, which cover approximately 9.6 million acres. During 2004, EnCana plans to conduct seismic surveys and drill one well.

EnCana has a 50 percent working interest in Block 5 in the Kingdom of Bahrain. Block 5 is comprised of approximately 97,000 gross acres (approximately 48,000 net acres).

Australia

In the fourth quarter of 2003, EnCana sold, subject to regulatory and other approvals, its 25 percent working interest in the John Brookes gas development on the North-West shelf (Blocks WA-214 and WA-205). EnCana has interests remaining in approximately 18.4 million gross acres (approximately 6.5 million net acres) in Australia.

Other

EnCana has also drilled a number of wells in various other countries over the past two years; however, no economic quantities of natural gas or crude oil were found.

## MIDSTREAM & MARKETING

### Midstream

EnCana's midstream activities are primarily comprised of natural gas storage operations, NGLs processing and power generation operations. In addition, EnCana has minor interests in transportation assets. EnCana's 2004 capital investment in core programs in its midstream operations is budgeted to be approximately $78 million.

#### *Natural Gas Storage*

Based upon overall storage capacity, EnCana is the largest independent (non-utility) natural gas storage operator in North America with facilities in Alberta, California and Oklahoma. EnCana also leases natural gas storage capacity from other storage operators located in the U.S. Gulf Coast and mid-continent regions. At December 31, 2003, EnCana had owned and operated storage capacity of approximately 134 billion cubic feet, as well as leased storage capacity of approximately 20 billion cubic feet. The Corporation expects this capacity to increase in 2004 and 2005 upon completion of the expansion of its Wild Goose Gas Storage Facility in northern California, completion of the new Countess Gas Storage Facility in southeast Alberta, and with development of the Starks project in southwest Louisiana.

EnCana provides a portion of its storage capacity under multi-year firm contracts to industry participants on a fee-for-service basis as well as offering short-term firm or interruptible storage services at market based rates. The remaining capacity is used as part of the natural gas storage optimization program (through the purchase and sale of third party gas) and is available to manage EnCana's produced gas sales.

AECO HUB™

EnCana operates and markets its Alberta natural gas storage facilities under the commercial name AECO HUB™. These facilities, all of which are 100 percent owned by EnCana, include the Suffield Gas Storage Facility, the Hythe Gas Storage Facility and the new Countess Gas Storage Facility. The AECO HUB™ is Canada's largest natural gas storage and trading hub.

*Suffield Gas Storage Facility*

Located on the Suffield Block, this facility was the first and is the most significant in the AECO HUB™ portfolio. It has undergone several expansions since start-up and now has storage capacity of approximately 85 billion cubic feet, a maximum withdrawal capability of approximately 1.8 billion cubic feet per day and a maximum injection capability of approximately 1.6 billion cubic feet per day.

*Hythe Gas Storage Facility*

In 1999, EnCana expanded its commercial natural gas storage capacity in Alberta through the conversion of a depleted reservoir at Hythe in northwest Alberta. This facility added approximately 10 billion cubic feet of working natural gas capacity, approximately 200 million cubic feet per day of withdrawal capability, and approximately 100 million cubic feet per day of injection capability. The Hythe Gas Storage Facility is connected to both the Alberta pipeline system of TransCanada Corporation and the Alliance Pipeline system. Commencing April 1, 2004, the compression and pipeline facilities related to the Hythe Gas Storage Facility are expected to be utilized by the Upstream division to facilitate incremental production from Cutbank Ridge. Consequently, this facility will not be available for use in providing storage services for a minimum term of one year.

*Countess Gas Storage Facility*

In October 2002, EnCana announced plans to develop a new natural gas storage facility in southeast Alberta that is expected to store up to 40 billion cubic feet of natural gas. The Countess Gas Storage Facility, designed for peak injections of 950 million cubic feet per day and peak withdrawals of 1.25 billion cubic feet per day, uses two depleted underground reservoirs located about 85 kilometres east of Calgary. The first

10 billion cubic feet of new storage capacity came online in October 2003. As of December 31, 2003, facilities construction was essentially complete, and storage capacity at Countess in 2004 is expected to be approximately 30 billion cubic feet. The full 40 billion cubic feet of storage capacity is expected to be utilized in 2005 after further analysis of initial reservoir performance.

Wild Goose Gas Storage Facility

In April 1999, Wild Goose Storage Inc. ("Wild Goose"), an indirect wholly owned subsidiary of EnCana, commenced commercial operation of a 14 billion cubic feet storage facility located north of Sacramento, in northern California. The Wild Goose Gas Storage Facility was California's first independent natural gas storage facility and currently has withdrawal capability of approximately 200 million cubic feet per day and injection capability of approximately 80 million cubic feet per day. In July 2002, Wild Goose was granted permission by the California Public Utilities Commission to approximately double the storage size and approximately triple the withdrawal capacity of the facility. Completion of the initial phase expansion is expected in April 2004, bringing the total working gas capacity to approximately 24 billion cubic feet. This expansion is also expected to increase withdrawal capability to approximately 480 million cubic feet per day and expand injection capability to approximately 450 million cubic feet per day.

Salt Plains Gas Storage Facility

In February 2001, Salt Plains Storage Inc., an indirect wholly owned subsidiary of EnCana, acquired substantially all of the assets of a 15 billion cubic feet storage facility located in northern Oklahoma. The Salt Plains Gas Storage Facility has a maximum withdrawal capability of approximately 200 million cubic feet per day and a maximum injection capability of approximately 100 million cubic feet per day.

Starks Project

In October 2003, EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, announced plans to develop a high-deliverability storage facility in southwest Louisiana. Subject to regulatory approvals, the facility is expected to be in-service during the third quarter of 2005 with approximately 8.65 billion cubic feet of working natural gas capacity, 375 million cubic feet of injection capacity and 400 million cubic feet of withdrawal capacity.

Leased Storage Capacity

EnCana Gas Storage Inc. has entered into contracts to lease storage capacity in the U.S. Gulf Coast and mid-continent regions. Total leased capacity at December 31, 2003 was approximately 20 billion cubic feet, with remaining contract terms ranging from three months to 13 years and an average remaining term of approximately five years.

***Natural Gas Liquids***

EnCana's NGLs midstream facilities and associated marketing resources are among the largest in Canada. The Corporation holds interests in four NGLs extraction plants that straddle two major natural gas pipelines at Empress, Alberta plus storage and fractionation assets in Saskatchewan, eastern Canada and the U.S.

At Empress, the rights to extract NGLs from natural gas transported through transmission pipelines are acquired from the shippers of the natural gas. In October 2003, the Corporation's Empress NGLs extraction plant completed an expansion that is expected to provide incremental ethane production of up to 17,000 barrels per day. As at December 31, 2003, EnCana's share of the combined processing capacity was approximately two billion cubic feet per day.

Ethane recovered at Empress is sold as a specification product to petrochemical companies for consumption within the Province of Alberta. The remaining liquids components are transported as a mixed stream by pipeline to a plant at Sarnia, Ontario in which EnCana holds an approximate 10.4 percent interest.

The mixed stream is fractionated at Sarnia into marketable products: propane, butane and pentanes plus. These are sold by Kinetic to distributors, refiners and petrochemical manufacturers in Canada and the U.S. under contracts, the terms of which are typically one year or less.

Other significant NGLs midstream assets include: (i) a one-third interest in a pipeline which delivers ethane from extraction plants located in Alberta at Waterton, Empress (four plants), Cochrane and Edmonton to ethylene plants at Joffre and Fort Saskatchewan and storage caverns at Fort Saskatchewan; (ii) a 50 percent interest in a pipeline that delivers NGLs from Empress to storage facilities and the Enbridge pipeline at Kerrobert, Saskatchewan; (iii) interests in a NGLs storage facility and depropanizer at Superior, Wisconsin; and (iv) a 49 percent interest in a propane and butane storage facility at Marysville, Michigan.

### *Power Generation*

EnCana has interests in two 106-megawatt power plants in southern Alberta, which supply electricity to the Power Pool of Alberta. The Cavalier Power Station began selling electricity to the Alberta Power Pool in late August 2001. The plant, located approximately 54 kilometres east of Calgary, is 100 percent owned and operated by EnCana. The Balzac Power Station, in which EnCana holds a 50 percent non-operated interest, is also located near Calgary and was brought into service in December 2001. The Corporation also has a 25 percent non-operated interest in a cogeneration facility in Kingston, Ontario. EnCana's power generation capacity, excluding power generated at the Foster Creek SAGD operation, is approximately 186 megawatts. In 2003, the Corporation generated 598,000 megawatt hours of EnCana owned electricity from the Cavalier, Balzac and Kingston plants (603,000 megawatt hours in 2002).

### *Transportation*

In February 2001, EnCana purchased a 36 percent equity interest in the Trasandino Pipeline system for approximately $64 million. The Trasandino system carries crude oil from Argentina's Neuquen Basin to refineries in Chile. The pipeline is 420 kilometres in length and has a design capacity of approximately 113,000 barrels per day. Shipments on the Trasandino system in 2003 averaged approximately 104,000 barrels per day (approximately 112,000 barrels per day in 2002).

## Marketing

### *Natural Gas Marketing*

In 2003, approximately 87 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 13 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

To mitigate the market risk associated with forecasted cash flows, EnCana entered into various risk management contracts relating to produced natural gas in 2003. The Corporation entered into fixed price AECO and NYMEX swaps and AECO and NYMEX collars as a means of protecting corporate cash flow to ensure sufficient funds for capital programs. To protect against weakening production area prices, EnCana entered into AECO and Rockies basis transactions. Details of these transactions are found in Note 17 to EnCana's audited consolidated financial statements for the year ended December 31, 2003.

In 2003, EnCana sold approximately 47 percent of its produced natural gas at fixed prices, approximately 9 percent at AECO Index based pricing, approximately 39 percent at NYMEX based pricing and approximately 5 percent at other prices. As of December 31, 2003, for 2004 EnCana has arranged for the sale of approximately 45 percent of its natural gas at fixed prices, approximately 9 percent exposed to AECO Index based prices, approximately 42 percent exposed to NYMEX based prices and approximately 4 percent at other prices.

In addition to sales of its proprietary production, EnCana purchases and sells natural gas for the purpose of optimizing the profitability of its midstream assets and the netback price to the Corporation. In 2003, EnCana's sales of purchased natural gas amounted to approximately 903 million cubic feet per day (approximately 962 million cubic feet per day in 2002).

***Crude Oil Marketing***

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (138,784 barrels per day in 2003 and 116,634 barrels per day in 2002). Crude oil sales are normally executed under spot and monthly evergreen contracts with delivery to major pipeline hubs, such as Edmonton, Hardisty or Cromer, in Alberta, with EnCana arranging the intermediate transportation on the feeder pipeline systems. Sales are also made on a delivered basis using trunk pipeline systems, such as Express, for sales to refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2003, EnCana acted as exclusive agent for COS and marketed COS' Syncrude volumes of 64,863 barrels per day (24,555 barrels per day in 2002). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government's Department of Energy (69,264 barrels per day in 2003 and 48,133 barrels per day in 2002). This agency agreement ends in the second quarter of 2007.

In Ecuador, EnCana's crude oil volumes are sold FOB at the marine loading facility at Balao, Esmeraldas Province, Ecuador. A total of 45,561 barrels per day was marketed in 2003 (37,253 barrels per day in 2002). Until September 2003, Ecuador production was transported from the Ecuador Oriente region to Balao via the SOTE Pipeline. EnCana began shipping on the OCP Pipeline in September 2003, and the pipeline was fully commissioned in November 2003. EnCana's production in Ecuador consists of a high viscosity crude oil with characteristics well-suited to refineries on the U.S. West and Gulf Coasts.

In the U.K., EnCana marketed 8,439 barrels per day of crude oil in 2003 (10,543 barrels per day in 2002).

To mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to crude oil. As of December 31, 2003, for 2004, EnCana had approximately 62,500 barrels per day in costless collars with a price floor averaging $20.00 per barrel and a price cap of $25.69 per barrel. Also for 2004, there are approximately 62,500 barrels per day in fixed price swaps with an average price of $23.13 per barrel. For 2005, EnCana has approximately 10,000 barrels per day in costless three-way put spreads. The three-way put spreads provide a price floor averaging $25.00 per barrel when the WTI price is above $20.00 or the WTI price plus $5.00 if the WTI price is below $20.00. The price cap set by the three-way put spreads is $28.775 per barrel.

***NGLs Marketing***

In 2003, Kinetic continued to market a portion of EnCana's western Canada NGLs primarily to eastern Canada and the U.S. Kinetic also markets NGLs on behalf of other parties.

***In the following section (pages 23-40), unless otherwise indicated, the information for EnCana for periods prior to April 5, 2002 (the date of the Merger) represents information for PanCanadian and does not combine the results of PanCanadian and AEC. Accordingly, the amounts shown exclude the results of AEC prior to April 5, 2002, and the amounts for 2001 and the first quarter of 2002 represent solely the results of PanCanadian.***

## RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's crude oil and natural gas reserves as of December 31, 2003. EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd., Gilbert Laustsen Jung Associates Ltd. and Ryder Scott Company, EnCana's continental U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc., EnCana's Ecuadorian reserves were evaluated by Ryder Scott Company and EnCana's U.K. reserves were evaluated by DeGolyer and MacNaughton. The previous year, 2002, was the first year for which all of EnCana's reserves were independently evaluated.

EnCana has a reserves committee of independent board members which reviews the qualifications and appointment of the independent qualified reserves evaluators. The committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the independent qualified reserves evaluators. The evaluations are conducted from the fundamental geological and engineering data.

Any references to NGLs in this section include condensate.

### Reserve Quantities Information

EnCana's reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions. Reserve acquisitions were approximately equal to reserve dispositions in 2003. The Corporation's reserves increased in 2002 predominantly from the Merger with AEC, and also partly due to extensions and discoveries. The 2002 increase was partially offset by downward revisions of reserve quantities. In 2001, the increase in reserves due to extensions and discoveries was offset by sales during the year.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69. The end of year numbers for 2003 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2002 represent estimates derived from the reports of the independent petroleum engineering consultants who evaluated EnCana's reserves as of December 31, 2002. The beginning and end of year numbers for 2001 represent internal estimates of PanCanadian at the time.

## Net Proved Reserves (EnCana Share After Royalties) (1,2)
## Constant Pricing

| | Natural Gas (billions of cubic feet) | | | | | Crude Oil and Natural Gas Liquids (millions of barrels) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Canada | United States | United Kingdom | Other | Total | Canada | United States | Ecuador | United Kingdom | Other | Total |
| **2001** | | | | | | | | | | | |
| Beginning of year | 3,350 | 208 | 10 | — | 3,568 | 348.0 | 16.7 | — | 23.7 | 5.0 | 393.4 |
| Revisions and improved recovery | 59 | 6 | — | — | 65 | 5.0 | 1.6 | — | 2.1 | — | 8.7 |
| Extensions and discoveries | 448 | 13 | — | — | 461 | 15.0 | 2.0 | — | — | — | 17.0 |
| Purchase of reserves in place | 1 | 25 | — | — | 26 | — | — | — | — | — | — |
| Sale of reserves in place | (1) | — | — | — | (1) | (48.0) | — | — | — | (5.0) | (53.0) |
| Production | (353) | (16) | (3) | — | (372) | (33.4) | (0.7) | — | (4.2) | — | (38.3) |
| End of Year | 3,504 | 236 | 7 | — | 3,747 | 286.6 | 19.6 | — | 21.6 | — | 327.8 |
| Developed | 2,908 | 172 | 7 | — | 3,087 | 245.3 | 14.9 | — | 21.6 | — | 281.8 |
| Undeveloped | 596 | 64 | — | — | 660 | 41.3 | 4.7 | — | — | — | 46.0 |
| Total | 3,504 | 236 | 7 | — | 3,747 | 286.6 | 19.6 | — | 21.6 | — | 327.8 |
| **2002** | | | | | | | | | | | |
| Beginning of year | 3,504 | 236 | 7 | — | 3,747 | 286.6 | 19.6 | — | 21.6 | — | 327.8 |
| Purchase of AEC reserves in place | 2,686 | 944 | — | — | 3,630 | 233.7 | 6.5 | 168.4 | — | — | 408.6 |
| Revisions and improved recovery | (1,140) | 731 | 7 | — | (402) | (15.5) | 4.6 | (33.5) | (9.1) | — | (53.5) |
| Extensions and discoveries | 726 | 319 | 10 | — | 1,055 | 96.9 | 3.3 | 31.1 | 89.2 | — | 220.5 |
| Purchase of reserves in place | 30 | 530 | — | — | 560 | 4.9 | 9.9 | — | — | — | 14.8 |
| Sale of reserves in place | (129) | (73) | — | — | (202) | (18.2) | (0.7) | — | — | — | (18.9) |
| Production | (604) | (114) | (4) | — | (722) | (46.5) | (2.3) | (10.2) | (4.1) | — | (63.1) |
| End of Year | 5,073 | 2,573 | 20 | — | 7,666 | 541.9 | 40.9 | 155.8 | 97.6 | — | 836.2 |
| Developed | 4,139 | 1,446 | 9 | — | 5,594 | 299.2 | 21.9 | 104.6 | 8.3 | — | 434.0 |
| Undeveloped | 934 | 1,127 | 11 | — | 2,072 | 242.7 | 19.0 | 51.2 | 89.3 | — | 402.2 |
| Total | 5,073 | 2,573 | 20 | — | 7,666 | 541.9 | 40.9 | 155.8 | 97.6 | — | 836.2 |
| **2003** | | | | | | | | | | | |
| Beginning of year | 5,073 | 2,573 | 20 | — | 7,666 | 541.9 | 40.9 | 155.8 | 97.6 | — | 836.2 |
| Revisions and improved recovery | 73 | 1 | 3 | — | 77 | 32.3 | 0.5 | 0.4 | 23.5 | — | 56.7 |
| Extensions and discoveries | 867 | 706 | — | 90 | 1,663 | 110.9 | 7.4 | 11.9 | — | 0.9 | 131.1 |
| Purchase of reserves in place | 9 | 152 | 8 | — | 169 | 1.3 | 0.9 | 17.3 | 7.1 | — | 26.6 |
| Sale of reserves in place | (60) | (88) | — | (90) | (238) | (0.2) | (4.7) | (5.1) | — | (0.9) | (10.9) |
| Production | (706) | (215) | (5) | — | (926) | (56.8) | (3.4) | (18.6) | (3.7) | — | (82.5) |
| End of Year | 5,256 | 3,129 | 26 | — | 8,411 | 629.4 | 41.6 | 161.7 | 124.5 | — | 957.2 |
| Developed | 3,984 | 1,833 | 13 | — | 5,830 | 306.1 | 26.3 | 115.0 | 16.7 | — | 464.1 |
| Undeveloped | 1,272 | 1,296 | 13 | — | 2,581 | 323.3 | 15.3 | 46.7 | 107.8 | — | 493.1 |
| Total | 5,256 | 3,129 | 26 | — | 8,411 | 629.4 | 41.6 | 161.7 | 124.5 | — | 957.2 |

Notes:

(1) Definitions:

a. "Net" reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.

b. "Proved" reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

c. "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

d. "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

### Other Disclosures About Oil and Gas Activities

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69.

#### *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*

In calculating the standardized measure of discounted future net cash flows, year end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's Syncrude interest (disposed of in 2003) and Midstream & Marketing interest.

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Future cash inflows | 35,126 | 29,890 | 10,768 | 17,472 | 9,398 | 845 | 3,533 | 3,368 | — |
| Future production and development costs | 14,018 | 8,686 | 3,070 | 2,889 | 3,360 | 285 | 987 | 908 | — |
| Undiscounted pre-tax cash flows | 21,108 | 21,204 | 7,698 | 14,583 | 6,038 | 560 | 2,546 | 2,460 | — |
| Future income taxes | 5,874 | 6,353 | 2,604 | 4,960 | 1,504 | 24 | 536 | 585 | — |
| Future net cash flows | 15,234 | 14,851 | 5,094 | 9,623 | 4,534 | 536 | 2,010 | 1,875 | — |
| Less discount of net cash flows using a 10% rate | 5,219 | 6,018 | 2,034 | 4,735 | 2,383 | 236 | 643 | 617 | — |
| Discounted future net cash flows | 10,015 | 8,833 | 3,060 | 4,888 | 2,151 | 300 | 1,367 | 1,258 | — |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Future cash inflows | 3,483 | 2,565 | 414 | — | — | — | 59,614 | 45,221 | 12,027 |
| Future production and development costs | 1,969 | 1,233 | 161 | — | — | — | 19,863 | 14,187 | 3,516 |
| Undiscounted pre-tax cash flows | 1,514 | 1,332 | 253 | — | — | — | 39,751 | 31,034 | 8,511 |
| Future income taxes | 456 | 483 | 53 | — | — | — | 11,826 | 8,925 | 2,681 |
| Future net cash flows | 1,058 | 849 | 200 | — | — | — | 27,925 | 22,109 | 5,830 |
| Less discount of net cash flows using a 10% rate | 493 | 438 | 60 | — | — | — | 11,090 | 9,456 | 2,330 |
| Discounted future net cash flows | 565 | 411 | 140 | — | — | — | 16,835 | 12,653 | 3,500 |

## Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Balance, beginning of year | 8,833 | 3,060 | 7,844 | 2,151 | 300 | 145 | 1,258 | — | — |
| Changes resulting from: | | | | | | | | | |
| Sales of oil and gas produced during the period | (3,429) | (2,092) | (1,701) | (889) | (329) | (47) | (258) | (157) | — |
| Discoveries and extensions, net of related costs | 1,272 | 1,293 | 487 | 1,381 | 293 | 36 | 126 | 330 | — |
| Purchases of proved AEC reserves in place | — | 6,810 | — | — | 1,044 | — | — | 1,830 | — |
| Purchases of proved reserves in place | 26 | 93 | 4 | 340 | 613 | 30 | 93 | — | — |
| Sales of proved reserves in place | (95) | (371) | (234) | (108) | (72) | — | (54) | — | — |
| Net change in prices and production costs | 242 | 3,358 | (7,561) | 2,751 | 194 | 109 | (47) | — | — |
| Revisions to quantity estimates | 416 | (1,345) | 90 | 4 | 667 | 12 | 4 | (354) | — |
| Accretion of discount | 1,636 | 455 | 1,197 | 304 | 56 | 21 | 182 | — | — |
| Future development costs incurred, net of changes | 340 | 101 | 180 | 534 | 54 | (70) | 89 | — | — |
| Other | 470 | (67) | 21 | 157 | (51) | — | (27) | — | — |
| Net change in income taxes | 304 | (2,462) | 2,733 | (1,737) | (618) | 64 | 1 | (391) | — |
| Balance, end of year | 10,015 | 8,833 | 3,060 | 4,888 | 2,151 | 300 | 1,367 | 1,258 | — |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Balance, beginning of year | 411 | 140 | 147 | — | — | 49 | 12,653 | 3,500 | 8,185 |
| Changes resulting from: | | | | | | | | | |
| Sales of oil and gas produced during the period | (83) | (81) | (89) | — | — | — | (4,659) | (2,659) | (1,837) |
| Discoveries and extensions, net of related costs | — | 594 | — | — | — | — | 2,779 | 2,510 | 523 |
| Purchases of proved AEC reserves in place | — | — | — | — | — | — | — | 9,684 | — |
| Purchases of proved reserves in place | 57 | — | — | — | — | — | 516 | 706 | 34 |
| Sales of proved reserves in place | — | — | — | — | — | (49) | (257) | (443) | (283) |
| Net change in prices and production costs | (119) | (1) | 12 | — | — | — | 2,827 | 3,551 | (7,440) |
| Revisions to quantity estimates | 157 | (53) | 19 | — | — | — | 581 | (1,085) | 121 |
| Accretion of discount | 91 | 14 | 32 | — | — | — | 2,213 | 525 | 1,250 |
| Future development costs incurred, net of changes | 108 | 3 | (4) | — | — | — | 1,071 | 158 | 106 |
| Other | (38) | (8) | — | — | — | — | 562 | (126) | 21 |
| Net change in income taxes | (19) | (197) | 23 | — | — | — | (1,451) | (3,668) | 2,820 |
| Balance, end of year | 565 | 411 | 140 | — | — | — | 16,835 | 12,653 | 3,500 |

*Results of Operations, Capitalized Costs and Costs Incurred*

## Results of Operations

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Oil and gas revenues, net of royalties, transportation and selling costs | 4,189 | 2,630 | 2,043 | 1,091 | 406 | 73 | 367 | 224 | — |
| Operating costs, production and mineral taxes | 760 | 538 | 342 | 202 | 77 | 26 | 109 | 67 | — |
| Depreciation, depletion and amortization | 1,511 | 871 | 385 | 297 | 206 | 31 | 159 | 79 | — |
| Operating income (loss) | 1,918 | 1,221 | 1,316 | 592 | 123 | 16 | 99 | 78 | — |
| Income taxes | 218 | 456 | 423 | 219 | 47 | 6 | 17 | 28 | — |
| Results of operations | 1,700 | 765 | 893 | 373 | 76 | 10 | 82 | 50 | — |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Oil and gas revenues, net of royalties, transportation and selling costs | 102 | 92 | 99 | — | — | — | 5,749 | 3,352 | 2,215 |
| Operating costs, production and mineral taxes | 19 | 11 | 10 | 20 | 29 | 1 | 1,110 | 722 | 379 |
| Depreciation, depletion and amortization | 74 | 39 | 42 | 83 | 35 | 17 | 2,124 | 1,230 | 475 |
| Operating income (loss) | 9 | 42 | 47 | (103) | (64) | (18) | 2,515 | 1,400 | 1,361 |
| Income taxes | 17 | 17 | 17 | (4) | — | — | 467 | 548 | 446 |
| Results of operations | (8) | 25 | 30 | (99) | (64) | (18) | 2,048 | 852 | 915 |

## Capitalized Costs

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Proved oil and gas properties | 18,549 | 12,504 | 7,704 | 3,485 | 2,769 | 471 | 1,372 | 1,000 | — |
| Unproved oil and gas properties | 1,981 | 1,573 | 203 | 501 | 415 | 116 | 70 | 60 | — |
| Total capital cost | 20,530 | 14,077 | 7,907 | 3,986 | 3,184 | 587 | 1,442 | 1,060 | — |
| Accumulated DD&A | 7,498 | 4,770 | 3,893 | 516 | 262 | 29 | 188 | 73 | — |
| Net capitalized costs | 13,032 | 9,307 | 4,014 | 3,470 | 2,922 | 558 | 1,254 | 987 | — |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | ($ millions) | | | | | | | | |
| Proved oil and gas properties | 675 | 445 | 288 | — | — | — | 24,081 | 16,718 | 8,463 |
| Unproved oil and gas properties | 77 | 3 | 44 | 317 | 226 | 144 | 2,946 | 2,277 | 507 |
| Total capital cost | 752 | 448 | 332 | 317 | 226 | 144 | 27,027 | 18,995 | 8,970 |
| Accumulated DD&A | 230 | 136 | 88 | 206 | 98 | 92 | 8,638 | 5,339 | 4,102 |
| Net capitalized costs | 522 | 312 | 244 | 111 | 128 | 52 | 18,389 | 13,656 | 4,868 |

## Costs Incurred

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | | | | | ($ millions) | | | | |
| Acquisitions | | | | | | | | | |
| — AEC unproved reserves | — | 1,496 | — | — | 444 | — | — | 221 | — |
| — other unproved reserves | 47 | 12 | 4 | 21 | 202 | 13 | 80 | — | — |
| — AEC proved reserves | — | 3,540 | — | — | 1,024 | — | — | 686 | — |
| — other proved reserves | 207 | 78 | 1 | 115 | 457 | 34 | 59 | — | — |
| Total acquisitions | 254 | 5,126 | 5 | 136 | 2,127 | 47 | 139 | 907 | — |
| Exploration | 846 | 403 | 304 | 187 | 226 | 129 | 20 | 35 | — |
| Development | 2,131 | 902 | 592 | 651 | 282 | 11 | 111 | 133 | — |
| Total costs incurred | 3,231 | 6,431 | 901 | 974 | 2,635 | 187 | 270 | 1,075 | — |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| | | | | | ($ millions) | | | | |
| Acquisitions | | | | | | | | | |
| — AEC unproved reserves | — | — | — | — | — | — | — | 2,161 | — |
| — other unproved reserves | 16 | — | — | — | — | — | 164 | 214 | 17 |
| — AEC proved reserves | — | — | — | — | — | — | — | 5,250 | — |
| — other proved reserves | 95 | — | — | — | — | 4 | 476 | 535 | 39 |
| Total acquisitions | 111 | — | — | — | — | 4 | 640 | 8,160 | 56 |
| Exploration | 30 | 16 | 25 | 78 | 118 | 41 | 1,161 | 798 | 499 |
| Development | 96 | 66 | 17 | — | — | — | 2,989 | 1,383 | 620 |
| Total costs incurred | 237 | 82 | 42 | 78 | 118 | 45 | 4,790 | 10,341 | 1,175 |

## Daily Sales Volumes, Royalty Rates and Per-Unit Results

### *Daily Sales Volumes*

The following tables summarize net daily sales volumes for EnCana on a quarterly basis for the periods indicated.

| | Daily Sales Volumes — 2003 (After Royalties) | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 1,935 | 2,008 | 1,914 | 1,899 | 1,922 |
| Inventory withdrawal/(injection) | 30 | — | — | — | 120 |
| Canada Sales | 1,965 | 2,008 | 1,914 | 1,899 | 2,042 |
| United States | 588 | 654 | 604 | 558 | 534 |
| United Kingdom | 13 | 20 | 7 | 12 | 13 |
| **Total Produced Gas** | 2,566 | 2,682 | 2,525 | 2,469 | 2,589 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 54,459 | 56,585 | 54,597 | 52,733 | 53,890 |
| Heavy oil | 87,867 | 95,059 | 94,985 | 82,001 | 79,171 |
| Natural gas liquids | | | | | |
| Canada | 14,278 | 13,348 | 13,758 | 14,740 | 15,291 |
| United States | 9,291 | 9,479 | 9,530 | 10,194 | 7,943 |
| Total North America | 165,895 | 174,471 | 172,870 | 159,668 | 156,295 |
| Ecuador | | | | | |
| Production | 51,089 | 72,731 | 54,582 | 36,754 | 39,893 |
| Transferred to OCP Pipeline[1] | (3,213) | — | (4,919) | (2,039) | (5,941) |
| Over/(under) lifting | (1,355) | 4,621 | (9,856) | 2,506 | (2,679) |
| Ecuador Sales | 46,521 | 77,352 | 39,807 | 37,221 | 31,273 |
| United Kingdom | 10,128 | 15,067 | 5,813 | 9,019 | 10,610 |
| **Total Oil and Natural Gas Liquids** | 222,544 | 266,890 | 218,490 | 205,908 | 198,178 |
| **Total** ***(barrels of oil equivalent/day)*** | 650,211 | 713,890 | 639,323 | 617,408 | 629,678 |
| Syncrude | 7,629 | — | 3,399 | 7,316 | 20,070 |

Notes:

(1) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

| | Daily Sales Volumes — 2002 (After Royalties) | | | | |
|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 1,717 | 1,943 | 1,959 | 1,980 | 975 |
| Inventory withdrawal/(injection) | (6) | 117 | (51) | (90) | — |
| Canada Sales | 1,711 | 2,060 | 1,908 | 1,890 | 975 |
| United States | 337 | 516 | 423 | 345 | 58 |
| United Kingdom | 10 | 8 | 9 | 8 | 11 |
| **Total Produced Gas** | 2,058 | 2,584 | 2,340 | 2,243 | 1,044 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 58,328 | 55,265 | 58,321 | 58,885 | 60,903 |
| Heavy oil | 58,890 | 77,090 | 70,795 | 67,558 | 19,350 |
| Natural gas liquids | | | | | |
| Canada | 13,852 | 15,987 | 13,985 | 14,168 | 11,212 |
| United States | 6,407 | 10,016 | 5,901 | 6,368 | 3,274 |
| Total North America | 137,477 | 158,358 | 149,002 | 146,979 | 94,739 |
| Ecuador | | | | | |
| Production | 27,625 | 34,856 | 37,447 | 37,702 | — |
| Over/(under) lifting | 2,115 | 1,044 | 2,316 | 5,088 | — |
| Ecuador Sales | 29,740 | 35,900 | 39,763 | 42,790 | — |
| United Kingdom | 10,528 | 7,786 | 9,538 | 11,966 | 12,889 |
| **Total Oil and Natural Gas Liquids** | 177,745 | 202,044 | 198,303 | 201,735 | 107,628 |
| **Total** ***(barrels of oil equivalent/day)*** | 520,745 | 632,711 | 588,303 | 575,568 | 281,628 |
| Syncrude | 23,540 | 33,918 | 35,585 | 24,152 | — |

| | Daily Sales Volumes — 2001 (After Royalties) | | | | |
|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 953 | 974 | 951 | 943 | 946 |
| Inventory withdrawal/(injection) | — | — | — | — | — |
| Canada Sales | 953 | 974 | 951 | 943 | 946 |
| United States | 43 | 55 | 48 | 36 | 33 |
| United Kingdom | 9 | 9 | 10 | 8 | 8 |
| **Total Produced Gas** | 1,005 | 1,038 | 1,009 | 987 | 987 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 60,332 | 58,591 | 62,250 | 59,511 | 60,981 |
| Heavy oil | 19,940 | 20,168 | 19,948 | 17,069 | 22,602 |
| Natural gas liquids | | | | | |
| Canada | 10,142 | 10,792 | 9,474 | 9,944 | 10,362 |
| United States | 2,443 | 2,224 | 2,954 | 2,207 | 2,383 |
| Total North America | 92,857 | 91,775 | 94,626 | 88,731 | 96,328 |
| United Kingdom | 11,362 | 10,839 | 12,669 | 10,914 | 11,012 |
| **Total Oil and Natural Gas Liquids** | 104,219 | 102,614 | 107,295 | 99,645 | 107,340 |
| **Total** ***(barrels of oil equivalent/day)*** | 271,719 | 275,614 | 275,462 | 264,145 | 271,840 |

### *Average Royalty Rates*

The following table sets forth average royalty rates on a quarterly basis for the periods indicated. These rates exclude the impact of financial hedging.

| | 2003 | | | | | 2002 | | | | | 2001 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 | Year | Q4 | Q3 | Q2 | Q1 | Year | Q4 | Q3 | Q2 | Q1 |
| | | | | | | | | (percent) | | | | | | | |
| **Produced Gas** | | | | | | | | | | | | | | | |
| Canada | 12.9 | 12.2 | 12.9 | 14.2 | 12.4 | 10.7 | 13.3 | 10.4 | 11.8 | 2.7 | 3.0 | 2.2 | 2.7 | 4.3 | 2.4 |
| United States | 20.0 | 19.5 | 20.2 | 20.1 | 20.5 | 21.1 | 21.1 | 23.1 | 19.4 | 19.4 | 30.6 | 23.6 | 22.6 | 42.9 | 36.5 |
| **Crude Oil** | | | | | | | | | | | | | | | |
| Canada and United States | 10.3 | 9.7 | 9.0 | 10.7 | 11.8 | 11.0 | 10.8 | 11.7 | 11.6 | 9.5 | 10.8 | 12.2 | 10.6 | 11.4 | 9.0 |
| Ecuador | 25.6 | 25.4 | 25.7 | 24.9 | 26.9 | 28.4 | 28.1 | 28.5 | 28.5 | — | — | — | — | — | — |
| **Natural Gas Liquids** | | | | | | | | | | | | | | | |
| Canada | 17.5 | 14.7 | 16.6 | 18.0 | 20.2 | 13.8 | 16.4 | 13.8 | 15.6 | 6.9 | 4.8 | 2.4 | 6.9 | 6.4 | 3.7 |
| United States | 17.6 | 17.5 | 17.0 | 17.3 | 18.5 | 10.8 | 13.3 | 12.0 | 10.5 | — | — | — | — | — | — |
| **Total Upstream** | 14.5 | 14.4 | 14.2 | 15.1 | 14.4 | 13.1 | 14.8 | 13.8 | 13.9 | 5.4 | 6.3 | 6.0 | 5.8 | 7.7 | 5.4 |

### *Per-Unit Results*

The following tables summarize net per-unit results for EnCana on a quarterly basis for the periods indicated.

| | Per-Unit Results — 2003 | | | | |
|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 |
| Produced Gas — Canada ($/Mcf) | | | | | |
| Price, net of royalties | 4.87 | 4.41 | 4.61 | 4.92 | 5.53 |
| Production and mineral taxes | 0.07 | 0.10 | 0.08 | 0.08 | 0.02 |
| Transportation and selling | 0.38 | 0.44 | 0.40 | 0.35 | 0.33 |
| Operating expenses | 0.48 | 0.45 | 0.50 | 0.47 | 0.48 |
| Netback excluding hedge | 3.94 | 3.42 | 3.63 | 4.02 | 4.70 |
| Financial hedge | (0.13) | 0.25 | (0.03) | (0.26) | (0.49) |
| Netback including hedge | 3.81 | 3.67 | 3.60 | 3.76 | 4.21 |
| Produced Gas — United States ($/Mcf) | | | | | |
| Price, net of royalties | 4.88 | 4.71 | 4.82 | 4.74 | 5.32 |
| Production and mineral taxes | 0.47 | 0.42 | 0.46 | 0.46 | 0.57 |
| Transportation and selling | 0.40 | 0.51 | 0.39 | 0.36 | 0.32 |
| Operating expenses | 0.28 | 0.29 | 0.33 | 0.31 | 0.20 |
| Netback excluding hedge | 3.73 | 3.49 | 3.64 | 3.61 | 4.23 |
| Financial hedge | 0.02 | (0.13) | (0.16) | (0.22) | 0.67 |
| Netback including hedge | 3.75 | 3.36 | 3.48 | 3.39 | 4.90 |
| Produced Gas — Total North America ($/Mcf) | | | | | |
| Price, net of royalties | 4.87 | 4.49 | 4.66 | 4.88 | 5.49 |
| Production and mineral taxes | 0.16 | 0.18 | 0.17 | 0.17 | 0.14 |
| Transportation and selling | 0.39 | 0.46 | 0.40 | 0.35 | 0.33 |
| Operating expenses | 0.43 | 0.41 | 0.46 | 0.43 | 0.42 |
| Netback excluding hedge | 3.89 | 3.44 | 3.63 | 3.93 | 4.60 |
| Financial hedge | (0.10) | 0.16 | (0.06) | (0.25) | (0.25) |
| Netback including hedge | 3.79 | 3.60 | 3.57 | 3.68 | 4.35 |
| Light and Medium Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 26.61 | 25.53 | 24.31 | 27.43 | 29.34 |
| Production and mineral taxes | 0.29 | 0.73 | (1.35) | 0.71 | 1.08 |
| Transportation and selling | 1.42 | 1.33 | 0.71 | 1.73 | 1.95 |
| Operating expenses | 6.00 | 6.28 | 5.93 | 6.07 | 5.68 |
| Netback excluding hedge | 18.90 | 17.19 | 19.02 | 18.92 | 20.63 |
| Financial hedge | (4.07) | (3.74) | (3.24) | (2.81) | (6.54) |
| Netback including hedge | 14.83 | 13.45 | 15.78 | 16.11 | 14.09 |

| | Per-Unit Results — 2003 | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Heavy Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 19.61 | 18.43 | 17.93 | 20.07 | 22.62 |
| Production and mineral taxes | (0.03) | 0.09 | (0.49) | 0.34 | (0.02) |
| Transportation and selling | 1.24 | 1.54 | 0.58 | 1.37 | 1.56 |
| Operating expenses | 5.67 | 4.95 | 5.93 | 6.18 | 5.70 |
| Netback excluding hedge | 12.73 | 11.85 | 11.91 | 12.18 | 15.38 |
| Financial hedge | (3.91) | (3.81) | (3.17) | (2.24) | (6.69) |
| Netback including hedge | 8.82 | 8.04 | 8.74 | 9.94 | 8.69 |
| Total Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 22.29 | 21.08 | 20.26 | 22.95 | 25.34 |
| Production and mineral taxes | 0.09 | 0.33 | (0.80) | 0.49 | 0.43 |
| Transportation and selling | 1.31 | 1.46 | 0.63 | 1.51 | 1.72 |
| Operating expenses | 5.80 | 5.45 | 5.93 | 6.13 | 5.70 |
| Netback excluding hedge | 15.09 | 13.84 | 14.50 | 14.82 | 17.49 |
| Financial hedge | (3.97) | (3.78) | (3.19) | (2.47) | (6.63) |
| Netback including hedge | 11.12 | 10.06 | 11.31 | 12.35 | 10.86 |
| Natural Gas Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 24.26 | 25.13 | 23.52 | 21.02 | 27.31 |
| Transportation and selling | 0.17 | 0.13 | 0.58 | — | — |
| Netback | 24.09 | 25.00 | 22.94 | 21.02 | 27.31 |
| Natural Gas Liquids — United States ($/bbl) | | | | | |
| Price, net of royalties | 26.97 | 26.68 | 25.50 | 24.64 | 32.18 |
| Production and mineral taxes | 2.03 | 2.69 | 2.64 | 1.21 | 1.55 |
| Netback | 24.94 | 23.99 | 22.86 | 23.43 | 30.63 |
| Natural Gas Liquids — Total North America ($/bbl) | | | | | |
| Price, net of royalties | 25.33 | 25.77 | 24.33 | 22.50 | 28.98 |
| Production and mineral taxes | 0.80 | 1.12 | 1.08 | 0.50 | 0.53 |
| Transportation and selling | 0.10 | 0.08 | 0.35 | — | — |
| Netback | 24.43 | 24.57 | 22.90 | 22.00 | 28.45 |
| Total Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 22.47 | 21.41 | 20.54 | 22.76 | 25.55 |
| Production and mineral taxes | 0.08 | 0.30 | (0.73) | 0.44 | 0.38 |
| Transportation and selling | 1.21 | 1.36 | 0.62 | 1.36 | 1.54 |
| Operating expenses | 5.27 | 5.01 | 5.43 | 5.53 | 5.11 |
| Netback excluding hedge | 15.91 | 14.74 | 15.22 | 15.43 | 18.52 |
| Financial hedge | (3.61) | (3.47) | (2.92) | (2.22) | (5.95) |
| Netback including hedge | 12.30 | 11.27 | 12.30 | 13.21 | 12.57 |
| Ecuador Oil ($/bbl) | | | | | |
| Price, net of royalties | 24.21 | 23.57 | 22.13 | 22.31 | 30.86 |
| Production and mineral taxes | 1.47 | 1.06 | 0.45 | 1.11 | 4.27 |
| Transportation and selling | 2.56 | 2.81 | 2.36 | 2.41 | 2.35 |
| Operating expenses | 4.84 | 4.62 | 4.33 | 5.63 | 5.09 |
| Netback excluding hedge | 15.34 | 15.08 | 14.99 | 13.16 | 19.15 |
| Financial hedge | — | — | — | — | — |
| Netback including hedge | 15.34 | 15.08 | 14.99 | 13.16 | 19.15 |
| United Kingdom Oil ($/bbl) | | | | | |
| Price, net of royalties | 28.11 | 27.05 | 27.92 | 27.17 | 30.61 |
| Transportation and selling | 1.97 | 1.70 | 1.98 | 1.86 | 2.45 |
| Operating expenses | 5.09 | 6.23 | 6.55 | 4.69 | 2.92 |
| Netback excluding hedge | 21.05 | 19.12 | 19.39 | 20.62 | 25.24 |
| Financial hedge | — | — | — | — | — |
| Netback including hedge | 21.05 | 19.12 | 19.39 | 20.62 | 25.24 |
| Total Liquids — All Countries ($/bbl) | | | | | |
| Price, net of royalties | 23.25 | 22.51 | 21.22 | 22.93 | 26.89 |
| Production and mineral taxes | 0.45 | 0.59 | (0.35) | 0.58 | 1.02 |
| Transportation and selling | 1.47 | 1.74 | 0.95 | 1.51 | 1.64 |
| Operating expenses | 4.93 | 4.75 | 5.01 | 5.22 | 4.77 |
| Netback excluding hedge | 16.40 | 15.43 | 15.61 | 15.62 | 19.46 |
| Financial hedge | (2.54) | (2.15) | (2.18) | (1.61) | (4.45) |
| Netback including hedge | 13.86 | 13.28 | 13.43 | 14.01 | 15.01 |

| | Per-Unit Results — 2002 | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Produced Gas — Canada ($/Mcf) | | | | | |
| Price, net of royalties[1] | 2.86 | 3.60 | 2.29 | 2.93 | 2.25 |
| Production and mineral taxes | 0.08 | 0.07 | 0.04 | 0.10 | 0.14 |
| Transportation and selling | 0.24 | 0.30 | 0.21 | 0.21 | 0.22 |
| Operating expenses | 0.41 | 0.44 | 0.42 | 0.40 | 0.31 |
| Netback excluding hedge | 2.13 | 2.79 | 1.62 | 2.22 | 1.58 |
| Financial hedge | 0.05 | (0.06) | 0.21 | (0.08) | 0.21 |
| Netback including hedge | 2.18 | 2.73 | 1.83 | 2.14 | 1.79 |
| Produced Gas — United States ($/Mcf) | | | | | |
| Price, net of royalties[1] | 2.96 | 3.48 | 2.78 | 2.51 | 2.36 |
| Production and mineral taxes | 0.27 | 0.34 | 0.22 | 0.23 | 0.29 |
| Transportation and selling | 0.47 | 0.46 | 0.76 | 0.23 | — |
| Operating expenses | 0.28 | 0.23 | 0.28 | 0.31 | 0.60 |
| Netback excluding hedge | 1.94 | 2.45 | 1.52 | 1.74 | 1.47 |
| Financial hedge | 0.29 | 0.34 | 0.47 | 0.05 | — |
| Netback including hedge | 2.23 | 2.79 | 1.99 | 1.79 | 1.47 |
| Produced Gas — Total North America ($/Mcf) | | | | | |
| Price, net of royalties[1] | 2.87 | 3.58 | 2.37 | 2.86 | 2.26 |
| Production and mineral taxes | 0.11 | 0.12 | 0.08 | 0.12 | 0.15 |
| Transportation and selling | 0.28 | 0.33 | 0.31 | 0.22 | 0.21 |
| Operating expenses | 0.39 | 0.40 | 0.39 | 0.39 | 0.32 |
| Netback excluding hedge | 2.09 | 2.73 | 1.59 | 2.13 | 1.58 |
| Financial hedge | 0.09 | 0.02 | 0.26 | (0.06) | 0.20 |
| Netback including hedge | 2.18 | 2.75 | 1.85 | 2.07 | 1.78 |
| Light and Medium Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 22.31 | 24.39 | 24.09 | 23.37 | 17.60 |
| Production and mineral taxes | 0.65 | 0.48 | 0.51 | 0.14 | 1.44 |
| Transportation and selling | 0.94 | 1.22 | 1.04 | 0.62 | 0.87 |
| Operating expenses | 4.80 | 5.15 | 4.72 | 5.29 | 4.08 |
| Netback excluding hedge | 15.92 | 17.54 | 17.82 | 17.32 | 11.21 |
| Financial hedge | (0.83) | (0.91) | (0.64) | (1.16) | (0.62) |
| Netback including hedge | 15.09 | 16.63 | 17.18 | 16.16 | 10.59 |
| Heavy Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 17.88 | 17.38 | 19.67 | 17.76 | 13.62 |
| Production and mineral taxes | 0.22 | 0.54 | 0.03 | 0.04 | 0.32 |
| Transportation and selling | 0.71 | 0.93 | 0.81 | 0.48 | 0.21 |
| Operating expenses | 4.58 | 4.12 | 4.96 | 4.39 | 5.73 |
| Netback excluding hedge | 12.37 | 11.79 | 13.87 | 12.85 | 7.36 |
| Financial hedge | (0.68) | (0.84) | (0.65) | (0.55) | (0.65) |
| Netback including hedge | 11.69 | 10.95 | 13.22 | 12.30 | 6.71 |
| Total Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 20.08 | 20.31 | 21.67 | 20.37 | 16.64 |
| Production and mineral taxes | 0.43 | 0.51 | 0.25 | 0.08 | 1.17 |
| Transportation and selling | 0.82 | 1.05 | 0.92 | 0.55 | 0.71 |
| Operating expenses | 4.69 | 4.55 | 4.85 | 4.81 | 4.48 |
| Netback excluding hedge | 14.14 | 14.20 | 15.65 | 14.93 | 10.28 |
| Financial hedge | (0.76) | (0.87) | (0.64) | (0.83) | (0.63) |
| Netback including hedge | 13.38 | 13.33 | 15.01 | 14.10 | 9.65 |
| Natural Gas Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 17.55 | 21.75 | 17.61 | 17.41 | 11.56 |
| Transportation and selling | — | — | — | — | — |
| Netback | 17.55 | 21.75 | 17.61 | 17.41 | 11.56 |

| | Per-Unit Results — 2002 | | | | |
|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 |
| Natural Gas Liquids — United States ($/bbl) | | | | | |
| Price, net of royalties | 23.75 | 25.14 | 25.64 | 23.57 | 16.31 |
| Production and mineral taxes | 1.02 | 0.94 | 1.32 | 1.37 | — |
| Netback | 22.73 | 24.20 | 24.32 | 22.20 | 16.31 |
| Natural Gas Liquids — Total North America ($/bbl) | | | | | |
| Price, net of royalties | 19.52 | 23.06 | 19.99 | 19.32 | 12.64 |
| Production and mineral taxes | 0.32 | 0.36 | 0.39 | 0.42 | — |
| Transportation and selling | — | — | — | — | — |
| Netback | 19.20 | 22.70 | 19.60 | 18.90 | 12.64 |
| Total Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 19.82 | 20.46 | 21.27 | 20.07 | 16.01 |
| Production and mineral taxes | 0.39 | 0.46 | 0.22 | 0.08 | 1.03 |
| Transportation and selling | 0.73 | 0.94 | 0.83 | 0.49 | 0.63 |
| Operating expenses | 4.19 | 4.06 | 4.38 | 4.32 | 3.93 |
| Netback excluding hedge | 14.51 | 15.00 | 15.84 | 15.18 | 10.42 |
| Financial hedge | (0.68) | (0.77) | (0.58) | (0.75) | (0.55) |
| Netback including hedge | 13.83 | 14.23 | 15.26 | 14.43 | 9.87 |
| Ecuador Oil ($/bbl) | | | | | |
| Price, net of royalties | 22.57 | 24.02 | 22.82 | 21.11 | — |
| Production and mineral taxes | 1.24 | 1.57 | 1.49 | 0.72 | — |
| Transportation and selling | 2.00 | 1.99 | 2.47 | 1.56 | — |
| Operating expenses | 4.86 | 5.35 | 4.12 | 5.13 | — |
| Netback excluding hedge | 14.47 | 15.11 | 14.74 | 13.70 | — |
| Financial hedge | (0.01) | — | — | (0.03) | — |
| Netback including hedge | 14.46 | 15.11 | 14.74 | 13.67 | — |
| United Kingdom Oil ($/bbl) | | | | | |
| Price, net of royalties | 24.76 | 25.73 | 27.07 | 25.92 | 21.18 |
| Transportation and selling | 1.69 | 1.53 | 1.92 | 1.62 | 1.65 |
| Operating expenses | 3.28 | 7.07 | 3.65 | 2.01 | 1.78 |
| Netback excluding hedge | 19.79 | 17.13 | 21.50 | 22.29 | 17.75 |
| Financial hedge | (0.06) | — | — | — | (0.19) |
| Netback including hedge | 19.73 | 17.13 | 21.50 | 22.29 | 17.56 |
| Total Liquids — All Countries ($/bbl) | | | | | |
| Price, net of royalties | 20.67 | 21.51 | 21.95 | 20.70 | 16.60 |
| Production and mineral taxes | 0.53 | 0.66 | 0.50 | 0.25 | 0.87 |
| Transportation and selling | 0.97 | 1.10 | 1.18 | 0.76 | 0.71 |
| Operating expenses | 4.09 | 4.18 | 4.16 | 4.21 | 3.53 |
| Netback excluding hedge | 15.08 | 15.57 | 16.11 | 15.48 | 11.49 |
| Financial hedge | (0.50) | (0.57) | (0.42) | (0.53) | (0.49) |
| Netback including hedge | 14.58 | 15.00 | 15.69 | 14.95 | 11.00 |

Notes:

(1) Excludes the effect of $108 million increase to consolidated revenues relating to the mark-to-market value of the AEC fixed price forward natural gas contracts recorded as part of the purchase price allocation.

| | Per-Unit Results — 2001 | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Produced Gas — Canada ($/Mcf) | | | | | |
| Price, net of royalties | 4.06 | 2.29 | 2.53 | 4.56 | 7.01 |
| Production and mineral taxes | 0.14 | 0.14 | 0.09 | 0.10 | 0.24 |
| Transportation and selling | 0.21 | 0.23 | 0.21 | 0.18 | 0.21 |
| Operating expenses | 0.32 | 0.35 | 0.33 | 0.33 | 0.28 |
| Netback excluding hedge | 3.39 | 1.57 | 1.90 | 3.95 | 6.28 |
| Financial hedge | 0.38 | 0.68 | 1.39 | 0.28 | (0.87) |
| Netback including hedge | 3.77 | 2.25 | 3.29 | 4.23 | 5.41 |
| Produced Gas — United States ($/Mcf) | | | | | |
| Price, net of royalties | 2.46 | 1.79 | 2.47 | 1.95 | 4.18 |
| Production and mineral taxes | 0.49 | 0.29 | 0.30 | 0.60 | 1.01 |
| Transportation and selling | — | — | — | — | — |
| Operating expenses | 0.68 | 0.51 | 0.87 | 0.71 | 0.61 |
| Netback excluding hedge | 1.29 | 0.99 | 1.30 | 0.64 | 2.56 |
| Financial hedge | — | — | — | — | — |
| Netback including hedge | 1.29 | 0.99 | 1.30 | 0.64 | 2.56 |
| Produced Gas — Total North America ($/Mcf) | | | | | |
| Price, net of royalties | 3.99 | 2.26 | 2.53 | 4.46 | 6.92 |
| Production and mineral taxes | 0.15 | 0.15 | 0.10 | 0.12 | 0.26 |
| Transportation and selling | 0.20 | 0.22 | 0.20 | 0.17 | 0.20 |
| Operating expenses | 0.33 | 0.36 | 0.35 | 0.34 | 0.29 |
| Netback excluding hedge | 3.31 | 1.53 | 1.88 | 3.83 | 6.17 |
| Financial hedge | 0.36 | 0.64 | 1.33 | 0.27 | (0.84) |
| Netback including hedge | 3.67 | 2.17 | 3.21 | 4.10 | 5.33 |
| Light and Medium Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 19.31 | 12.56 | 22.62 | 20.54 | 21.29 |
| Production and mineral taxes | 0.78 | 0.93 | 0.52 | 1.31 | 0.40 |
| Transportation and selling | 0.70 | 0.55 | 0.75 | 0.61 | 0.88 |
| Operating expenses | 4.78 | 4.25 | 4.71 | 5.35 | 4.81 |
| Netback excluding hedge | 13.05 | 6.83 | 16.64 | 13.27 | 15.20 |
| Financial hedge | 0.80 | 5.43 | (0.26) | (0.59) | (1.27) |
| Netback including hedge | 13.85 | 12.26 | 16.38 | 12.68 | 13.93 |
| Heavy Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 11.41 | 7.77 | 16.62 | 11.21 | 10.15 |
| Production and mineral taxes | 0.50 | 0.43 | 0.39 | 0.65 | 0.54 |
| Transportation and selling | 0.12 | 0.11 | 0.14 | (0.02) | 0.20 |
| Operating expenses | 6.63 | 6.89 | 5.68 | 8.06 | 6.15 |
| Netback excluding hedge | 4.16 | 0.34 | 10.41 | 2.52 | 3.26 |
| Financial hedge | — | — | — | — | — |
| Netback including hedge | 4.16 | 0.34 | 10.41 | 2.52 | 3.26 |
| Total Oil — North America ($/bbl) | | | | | |
| Price, net of royalties | 17.35 | 11.33 | 21.16 | 18.46 | 18.28 |
| Production and mineral taxes | 0.71 | 0.80 | 0.49 | 1.16 | 0.44 |
| Transportation and selling | 0.55 | 0.44 | 0.60 | 0.47 | 0.70 |
| Operating expenses | 5.24 | 4.93 | 4.95 | 5.96 | 5.17 |
| Netback excluding hedge | 10.85 | 5.16 | 15.12 | 10.87 | 11.97 |
| Financial hedge | 0.60 | 4.04 | (0.20) | (0.46) | (0.93) |
| Netback including hedge | 11.45 | 9.20 | 14.92 | 10.41 | 11.04 |
| Natural Gas Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 19.70 | 13.25 | 18.24 | 22.30 | 25.42 |
| Transportation and selling | — | — | — | — | — |
| Netback | 19.70 | 13.25 | 18.24 | 22.30 | 25.42 |

| | Per-Unit Results — 2001 | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Natural Gas Liquids — United States ($/bbl) | | | | | |
| Price, net of royalties | 22.22 | 16.75 | 20.90 | 24.40 | 27.08 |
| Production and mineral taxes | — | — | — | — | — |
| Netback | 22.22 | 16.75 | 20.90 | 24.40 | 27.08 |
| Natural Gas Liquids — Total North America ($/bbl) | | | | | |
| Price, net of royalties | 20.19 | 13.85 | 18.87 | 22.68 | 25.73 |
| Production and mineral taxes | — | — | — | — | — |
| Transportation and selling | — | — | — | — | — |
| Netback | 20.19 | 13.85 | 18.87 | 22.68 | 25.73 |
| Total Liquids — Canada ($/bbl) | | | | | |
| Price, net of royalties | 17.61 | 11.56 | 20.86 | 18.90 | 19.06 |
| Production and mineral taxes | 0.63 | 0.70 | 0.44 | 1.03 | 0.39 |
| Transportation and selling | 0.49 | 0.38 | 0.54 | 0.41 | 0.62 |
| Operating expenses | 4.65 | 4.33 | 4.44 | 5.27 | 4.60 |
| Netback excluding hedge | 11.84 | 6.15 | 15.44 | 12.19 | 13.45 |
| Financial hedge | 0.53 | 3.55 | (0.18) | (0.41) | (0.83) |
| Netback including hedge | 12.37 | 9.70 | 15.26 | 11.78 | 12.62 |
| United Kingdom Oil ($/bbl) | | | | | |
| Price, net of royalties | 24.62 | 19.72 | 23.26 | 26.78 | 28.67 |
| Transportation and selling | 1.68 | 1.55 | 1.76 | 1.68 | 1.72 |
| Operating expenses | 2.69 | 4.00 | 2.04 | 1.83 | 3.09 |
| Netback excluding hedge | 20.25 | 14.17 | 19.46 | 23.27 | 23.86 |
| Financial hedge | 0.46 | 4.59 | (0.77) | (1.56) | 0.05 |
| Netback including hedge | 20.71 | 18.76 | 18.69 | 21.71 | 23.91 |
| Total Liquids — All Countries ($/bbl) | | | | | |
| Price, net of royalties | 18.44 | 12.52 | 21.11 | 19.85 | 20.19 |
| Production and mineral taxes | 0.55 | 0.61 | 0.37 | 0.89 | 0.34 |
| Transportation and selling | 0.60 | 0.48 | 0.66 | 0.54 | 0.71 |
| Operating expenses | 4.31 | 4.16 | 4.02 | 4.77 | 4.33 |
| Netback excluding hedge | 12.98 | 7.27 | 16.06 | 13.65 | 14.81 |
| Financial hedge | 0.51 | 3.54 | (0.24) | (0.52) | (0.72) |
| Netback including hedge | 13.49 | 10.81 | 15.82 | 13.13 | 14.09 |

## Drilling Activity

The following tables summarize EnCana's gross participation and net interest in wells drilled for 2001, 2002 and 2003.

### Exploration Wells Drilled

| | Gas | | Oil | | Dry & Abandoned | | Total Working Interest | | Royalty | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Gross | Net |
| **2003:** | | | | | | | | | | | |
| Canada | 532 | 511 | 51 | 31 | 35 | 28 | 618 | 570 | 153 | 771 | 570 |
| United States | 40 | 35 | 7 | 2 | 4 | 2 | 51 | 39 | — | 51 | 39 |
| Ecuador | — | — | 3 | 2 | — | — | 3 | 2 | — | 3 | 2 |
| United Kingdom | — | — | 2 | 1 | 5 | 3 | 7 | 4 | — | 7 | 4 |
| Other | 1 | — | — | — | 3 | 1 | 4 | 1 | — | 4 | 1 |
| Total | 573 | 546 | 63 | 36 | 47 | 34 | 683 | 616 | 153 | 836 | 616 |
| **2002:** | | | | | | | | | | | |
| Canada | 423 | 382 | 84 | 72 | 44 | 37 | 551 | 491 | 190 | 741 | 491 |
| United States | 12 | 12 | 2 | 1 | 3 | 1 | 17 | 14 | — | 17 | 14 |
| Ecuador | — | — | 7 | 5 | — | — | 7 | 5 | — | 7 | 5 |
| United Kingdom | — | — | 7 | 3 | 2 | 1 | 9 | 4 | — | 9 | 4 |
| Other | — | — | — | — | 4 | 2 | 4 | 2 | — | 4 | 2 |
| Total | 435 | 394 | 100 | 81 | 53 | 41 | 588 | 516 | 190 | 778 | 516 |
| **2001:** | | | | | | | | | | | |
| Canada | 403 | 328 | 81 | 59 | 105 | 90 | 589 | 477 | 260 | 849 | 477 |
| United States | 13 | 11 | 1 | — | 2 | — | 16 | 11 | — | 16 | 11 |
| Ecuador | — | — | — | — | — | — | — | — | — | — | — |
| United Kingdom | — | — | 1 | — | 2 | 1 | 3 | 1 | — | 3 | 1 |
| Other | — | — | — | — | 4 | 1 | 4 | 1 | — | 4 | 1 |
| Total | 416 | 339 | 83 | 59 | 113 | 92 | 612 | 490 | 260 | 872 | 490 |

### Development Wells Drilled

| | Gas | | Oil | | Dry & Abandoned | | Total Working Interest | | Royalty | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Gross | Net |
| **2003:** | | | | | | | | | | | |
| Canada | 3,964 | 3,901 | 756 | 650 | 24 | 18 | 4,744 | 4,569 | 1,347 | 6,091 | 4,569 |
| United States | 426 | 401 | — | — | 1 | 1 | 427 | 402 | — | 427 | 402 |
| Ecuador | — | — | 53 | 39 | 6 | 6 | 59 | 45 | — | 59 | 45 |
| United Kingdom | — | — | 3 | — | — | — | 3 | — | — | 3 | — |
| Total | 4,390 | 4,302 | 812 | 689 | 31 | 25 | 5,233 | 5,016 | 1,347 | 6,580 | 5,016 |
| **2002:** | | | | | | | | | | | |
| Canada | 1,397 | 1,340 | 433 | 349 | 30 | 23 | 1,860 | 1,712 | 690 | 2,550 | 1,712 |
| United States | 287 | 250 | 3 | 3 | 1 | 1 | 291 | 254 | — | 291 | 254 |
| Ecuador | — | — | 44 | 37 | 5 | 4 | 49 | 41 | — | 49 | 41 |
| United Kingdom | — | — | 2 | — | — | — | 2 | — | — | 2 | — |
| Total | 1,684 | 1,590 | 482 | 389 | 36 | 28 | 2,202 | 2,007 | 690 | 2,892 | 2,007 |
| **2001:** | | | | | | | | | | | |
| Canada | 1,125 | 1,052 | 333 | 198 | 35 | 29 | 1,493 | 1,279 | 1,227 | 2,720 | 1,279 |
| United States | 83 | 47 | — | — | 3 | 1 | 86 | 48 | — | 86 | 48 |
| Ecuador | — | — | — | — | — | — | — | — | — | — | — |
| United Kingdom | — | — | 4 | 1 | — | — | 4 | 1 | — | 4 | 1 |
| Total | 1,208 | 1,099 | 337 | 199 | 38 | 30 | 1,583 | 1,328 | 1,227 | 2,810 | 1,328 |

Notes:

(1) "Gross" wells are the total number of wells in which EnCana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating EnCana's working interest in each of its gross wells.

At December 31, 2003, EnCana was in the process of drilling 23 gross wells (21 net wells) in Canada, 20 gross wells (20 net wells) in the United States, 4 gross wells (1.9 net wells) in Ecuador, 1 gross well (0.3 net wells) in the United Kingdom and 2 gross wells (0.9 net wells) in other countries.

## Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2003:

**Location of Wells**
**As at December 31, 2003**

| | Gas | | Oil | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 25,200 | 23,693 | 6,224 | 5,104 | 31,424 | 28,797 |
| British Columbia | 827 | 703 | 8 | 7 | 835 | 710 |
| Saskatchewan | 548 | 400 | 3,571 | 1,832 | 4,119 | 2,232 |
| Total Canada | 26,575 | 24,796 | 9,803 | 6,943 | 36,378 | 31,739 |
| Colorado | 2,133 | 1,878 | 7 | 3 | 2,140 | 1,881 |
| Montana | 44 | 39 | — | — | 44 | 39 |
| Texas | 167 | 163 | 1 | 1 | 168 | 164 |
| Wyoming | 543 | 363 | 1 | 1 | 544 | 364 |
| Gulf of Mexico | — | — | 4 | 1 | 4 | 1 |
| Total United States | 2,887 | 2,443 | 13 | 6 | 2,900 | 2,449 |
| United Kingdom | 1 | — | 38 | 11 | 39 | 11 |
| Ecuador | — | — | 231 | 189 | 231 | 189 |
| Total | 29,463 | 27,239 | 10,085 | 7,149 | 39,548 | 34,388 |

Notes:

(1) EnCana has varying royalty interests in 8,715 crude oil wells and 11,661 natural gas wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 10,773 gross natural gas wells (9,953 net wells) and 321 gross crude oil wells (177 net wells).

## Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2003:

| | | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|---|
| | | Gross | Net | Gross | Net | Gross | Net |
| | | | | (thousands of acres) | | | |
| Canada | | | | | | | |
| Alberta | — Fee | 2,566 | 2,422 | 2,746 | 2,717 | 5,312 | 5,139 |
| | — Crown | 3,710 | 3,149 | 6,986 | 5,978 | 10,696 | 9,127 |
| | — Freehold | 197 | 63 | 554 | 279 | 751 | 342 |
| | | 6,473 | 5,634 | 10,286 | 8,974 | 16,759 | 14,608 |
| British Columbia | — Fee | — | — | 7 | 7 | 7 | 7 |
| | — Crown | 656 | 549 | 4,850 | 4,031 | 5,506 | 4,580 |
| | | 656 | 549 | 4,857 | 4,038 | 5,513 | 4,587 |
| Saskatchewan | — Fee | 12 | 10 | 481 | 467 | 493 | 477 |
| | — Crown | 345 | 214 | 1,326 | 1,128 | 1,671 | 1,342 |
| | — Freehold | 73 | 37 | 235 | 157 | 308 | 194 |
| | | 430 | 261 | 2,042 | 1,752 | 2,472 | 2,013 |
| Manitoba | — Fee | — | — | 271 | 266 | 271 | 266 |
| | — Crown | — | — | 30 | 30 | 30 | 30 |
| | — Freehold | — | — | 23 | 23 | 23 | 23 |
| | | — | — | 324 | 319 | 324 | 319 |
| Nova Scotia | — Crown | — | — | 4,404 | 2,988 | 4,404 | 2,988 |
| Newfoundland & Labrador | — Crown | — | — | 4,294 | 2,781 | 4,294 | 2,781 |
| Northwest Territories | — Crown | — | — | 1,019 | 459 | 1,019 | 459 |
| Nunavut | — Crown | — | — | 817 | 26 | 817 | 26 |
| Beaufort | — Crown | — | — | 126 | 4 | 126 | 4 |
| **Total Canada** | | 7,559 | 6,444 | 28,169 | 21,341 | 35,728 | 27,785 |

| | | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|---|
| | | Gross | Net | Gross | Net | Gross | Net |
| | | | | (thousands of acres) | | | |
| United States | | | | | | | |
| Colorado | — Federal/State Lands | 173 | 144 | 439 | 381 | 612 | 525 |
| | — Freehold | 84 | 70 | 215 | 186 | 299 | 256 |
| | — Fee | 4 | 3 | 9 | 8 | 13 | 11 |
| | | 261 | 217 | 663 | 575 | 924 | 792 |
| Wyoming | — Federal/State Lands | 58 | 23 | 640 | 463 | 698 | 486 |
| | — Freehold | 4 | 2 | 46 | 33 | 50 | 35 |
| | | 62 | 25 | 686 | 496 | 748 | 521 |
| Alaska | — Federal/State Lands | — | — | 1,794 | 802 | 1,794 | 802 |
| Gulf of Mexico. | — Federal/State Lands | — | — | 1,511 | 663 | 1,511 | 663 |
| Other | — Federal Lands | 10 | 7 | 320 | 270 | 330 | 277 |
| | — Freehold | 18 | 12 | 259 | 126 | 277 | 138 |
| | | 28 | 19 | 579 | 396 | 607 | 415 |
| **Total United States** | | 351 | 261 | 5,233 | 2,932 | 5,584 | 3,193 |
| Ecuador | | 141 | 80 | 1,258 | 811 | 1,399 | 891 |
| United Kingdom | | 44 | 12 | 1,822 | 744 | 1,866 | 756 |
| Chad | | — | — | 108,536 | 54,268 | 108,536 | 54,268 |
| Oman | | — | — | 9,606 | 9,606 | 9,606 | 9,606 |
| Australia | | — | — | 18,396 | 6,512 | 18,396 | 6,512 |
| Qatar | | — | — | 2,758 | 2,758 | 2,758 | 2,758 |
| Ghana | | — | — | 3,677 | 1,471 | 3,677 | 1,471 |
| Yemen | | — | — | 1,879 | 987 | 1,879 | 987 |
| Greenland | | — | — | 985 | 862 | 985 | 862 |
| Brazil | | — | — | 161 | 108 | 161 | 108 |
| Bahrain | | — | — | 97 | 48 | 97 | 48 |
| Azerbaijan | | — | — | 346 | 17 | 346 | 17 |
| **Total International** | | 185 | 92 | 149,521 | 78,192 | 149,706 | 78,284 |
| **Total** | | 8,095 | 6,797 | 182,923 | 102,465 | 191,018 | 109,262 |

Notes:

(1) This table excludes approximately 3.6 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those in which EnCana owns mineral rights and in which it retains a working interest.

(3) Crown / Federal / State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.

(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.

(5) Gross acres are the total area of properties in which EnCana has an interest.

(6) Net acres are the sum of EnCana's fractional interest in gross acres.

**Acquisitions, Dispositions and Capital Expenditures**

EnCana's growth in recent years has been achieved through both internal growth and acquisitions. EnCana has a large inventory of internal growth opportunities and also continues to examine acquisition opportunities to develop and expand its business. The acquisition opportunities may include significant corporate or asset acquisitions and EnCana may finance any such acquisitions with debt or equity or a combination of both.

The following table summarizes EnCana's net capital investment for 2002 and 2003. *Information for 2002 is presented on the basis of combining the results for PanCanadian and AEC for the period prior to the Merger.*

**Net Capital Investment**
***($ million)***

| | 2003 | 2002 |
|---|---|---|
| Upstream | | |
| Canada | 2,937 | 1,601 |
| United States | 830 | 616 |
| Ecuador | 265 | 212 |
| United Kingdom | 112 | 82 |
| Other Countries | 78 | 113 |
| | 4,222 | 2,624 |
| Midstream & Marketing | 223 | 51 |
| Corporate | 57 | 46 |
| Core Capital | 4,502 | 2,721 |
| Acquisitions | | |
| Upstream | | |
| Property | 510 | 786 |
| Corporate | 207 | — |
| Midstream & Marketing | 53 | — |
| Corporate | 50 | — |
| Dispositions | | |
| Upstream | (301) | (385) |
| Corporate | (14) | (60) |
| Net Capital Investment — Continuing Operations | 5,007 | 3,062 |
| Discontinued Operations | (1,585) | 172 |
| Total Net Capital Investment | 3,422 | 3,234 |

As part of a regular dispositions program, EnCana plans to dispose of approximately $365 million of non-core assets in 2004, which includes EnCana's interest in Petrovera sold in February 2004.

**Delivery Commitments**

As part of ordinary business operations, EnCana has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. These commitments comprise a small portion of EnCana's total revenues and the Corporation has sufficient reserves to meet these commitments. More detailed information relating to such commitments can be found in Note 19 to EnCana's audited consolidated financial statements for the year ended December 31, 2003.

## GENERAL

### Competitive Conditions

All aspects of the oil and natural gas industry are highly competitive and EnCana actively competes with oil and natural gas and other companies for reserve acquisitions, exploration leases, licenses and concessions, midstream assets and industry personnel.

### Environmental Protection

EnCana's worldwide operations are subject to government laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations generally require EnCana to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Corporate Responsibility, Environment, Health and Safety Committee of EnCana's Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. EnCana does not anticipate making material expenditures for compliance with environmental regulations in 2004. In 2003, the Corporation adopted Canadian Institute of Chartered Accountants Handbook Section 3110 "Asset Retirement Obligations", whereby the Corporation includes the fair value of future asset retirement obligations for abandonment and reclamation costs in the audited consolidated financial statements.

Based on EnCana's current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at $3.2 billion.

### Employees

At December 31, 2003, EnCana employed 3,854 full time equivalent ("FTE") employees as set forth in the following table:

| | Number of FTE Employees As at December 31, 2003 |
|---|---|
| Upstream | 2,808 |
| Midstream & Marketing | 280 |
| Corporate | 766 |
| **Total** | 3,854 |

### Foreign Operations

As at December 31, 2003, approximately 90 percent of EnCana's reserves and production were located in North America, which limits EnCana's exposure to risks and uncertainties in countries considered politically and economically unstable. EnCana's operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of EnCana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. The Corporation has undertaken to mitigate these risks where practical and considered warranted.

## SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following sets forth selected financial information for EnCana for the periods indicated. The information for EnCana includes the results of AEC from the closing date of the Merger. As such, the amounts reported for EnCana for the year ended December 31, 2002 reflect 12 months of PanCanadian or EnCana results, combined with the nine months of post-Merger AEC results. The amounts for EnCana for 2001 represent solely the results of PanCanadian.

| | Year Ended December 31 | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | ($million, except per share amounts) | | |
| Revenues, net of royalties | 10,216 | 6,276 | 3,244 |
| Cash flow from continuing operations[3,5] | 4,420 | 2,267 | 1,463 |
| Cash flow[5] | 4,459 | 2,419 | 1,494 |
| Net earnings from continuing operations[1,2,3] | 2,167 | 735 | 832 |
| Net earnings[1,2] | 2,360 | 812 | 854 |
| Total assets | 24,110 | 19,912 | 6,823 |
| Long-term debt | 6,088 | 5,051 | 1,467 |
| Cash dividends[4] | 139 | 108 | 818 |
| **Per Share Data**[1,2] | | | |
| Cash flow from continuing operations[5] | | | |
| Per share — basic | 9.32 | 5.43 | 5.72 |
| Per share — diluted | 9.21 | 5.36 | 5.65 |
| Cash flow[5] | | | |
| Per share — basic | 9.41 | 5.79 | 5.85 |
| Per share — diluted | 9.30 | 5.72 | 5.77 |
| Net earnings from continuing operations | | | |
| Per share — basic | 4.57 | 1.76 | 3.26 |
| Per share — diluted | 4.52 | 1.74 | 3.21 |
| Net earnings | | | |
| Per share — basic | 4.98 | 1.94 | 3.34 |
| Per share — diluted | 4.92 | 1.92 | 3.30 |

Notes:

(1) In accordance with Canadian GAAP, the Corporation is required to translate long-term debt issued in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings or, in the case of long-term debt held by self-sustaining operations, in the currency translation adjustment account included in Shareholders' Equity in the Consolidated Balance Sheet. As a result, 2003 net earnings includes an after-tax unrealized foreign exchange gain of $433 million (2002 — $17 million gain; 2001 — $28 million loss).

(2) Canadian GAAP requires the Corporation to recognize impacts of tax rate changes that are substantively enacted. Gains or losses from these changes are recorded in the Consolidated Statement of Earnings and included as an adjustment to Future Income Taxes in the Consolidated Balance Sheet. Tax rate reductions increased 2003 net earnings by $359 million (2002 — $20 million; 2001 — $53 million).

(3) Following the Merger, the Corporation determined to discontinue the Houston-based merchant energy operation of a subsidiary of its predecessor company, PanCanadian, which was included in the Midstream & Marketing segment. Accordingly, these operations were accounted for as discontinued operations. On July 9, 2002, the Corporation announced that it planned to sell its 70 percent equity investment in Cold Lake and its 100 percent interest in Express. Both crude oil pipeline systems were acquired in the business combination with AEC on April 5, 2002. These sales were completed in January 2003 for $1.0 billion (C$1.6 billion), including the assumption of debt, with a resulting after-tax gain on sale of $169 million. Accordingly, these operations were accounted for as discontinued operations. On February 28, 2003, the Corporation completed the sale of its 10 percent working interest in Syncrude to COS for net cash consideration of $690 million (C$1,026 million), subject to post-closing adjustments. On July 10, 2003 the Corporation completed the sale of its remaining 3.75 percent interest in Syncrude and a gross overriding royalty for net cash consideration of $309 million (C$427 million), subject to post-closing adjustments. This transaction completed the Corporation's disposition of its interests in Syncrude and, as a result, these operations have been accounted for as discontinued operations.

(4) Represents cash dividends paid to common shareholders at a rate of C$0.40 per share annually. As part of the CPL reorganization, the Corporation paid a Special Dividend of $754 million (C$1,180 million or C$4.60 per common share) on September 14, 2001. The amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the quarterly dividend. EnCana's Board of Directors has declared a dividend of $0.10 per share payable on March 31, 2004 to common shareholders of record on March 15, 2004. EnCana's dividend policy is examined annually by the Board of Directors.

(5) Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic, Cash Flow per share-diluted are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this annual information form in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity and its ability to generate funds to finance its operations. Management utilizes Cash Flow and Cash Flow from Continuing Operations as key measures to assess the ability of the Corporation to finance operating activities and capital expenditures.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis for the year ended December 31, 2003, accompanying the 2003 audited consolidated financial statements, is incorporated by reference.

## MARKET FOR SECURITIES

All of the outstanding common shares of EnCana are listed and posted for trading on the Toronto Stock Exchange and the New York Stock Exchange. The Corporation's Coupon Reset Subordinated Term Securities, Series A ("Term Securities") and 8.50 percent Preferred Securities are listed and posted for trading on the Toronto Stock Exchange and the Corporation's 9.50 percent Preferred Securities are listed and posted for trading on the New York Stock Exchange.

In February 2004, EnCana announced its intention to redeem all of the Term Securities on March 23, 2004.

## DIRECTORS AND OFFICERS

The following information is provided for each director and executive officer of EnCana as at the date of this annual information form:

### Directors

| Name and Municipality of Residence | Director Since[13] | Principal Occupation |
|---|---|---|
| MICHAEL N. CHERNOFF[2,6] . . . . . . . . . . . . . .<br>West Vancouver, British Columbia | 1999 | Corporate Director |
| RALPH S. CUNNINGHAM[2,3] . . . . . . . . . . . . . .<br>Montgomery, Texas | 2003 | Corporate Director |
| PATRICK D. DANIEL[1,5] . . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 2001 | President & Chief Executive Officer<br>Enbridge Inc.<br>*(Energy, transportation and services)* |
| IAN W. DELANEY[3,4] . . . . . . . . . . . . . . . . . . .<br>Toronto, Ontario | 1999 | Chairman of the Board<br>Sherritt International Corporation<br>*(Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)* |
| WILLIAM R. FATT[1,8] . . . . . . . . . . . . . . . . . . .<br>Toronto, Ontario | 1995 | Chief Executive Officer<br>Fairmont Hotels & Resorts Inc.<br>*(Hotels)* |
| MICHAEL A. GRANDIN[3,5,6,9] . . . . . . . . . . . . .<br>Calgary, Alberta | 1998 | Chairman & Chief Executive Officer<br>Fording Canadian Coal Trust<br>*(Metallurgical coal)* |
| BARRY W. HARRISON[1,4,10] . . . . . . . . . . . . . .<br>Calgary, Alberta | 1996 | Corporate Director and independent businessman |
| RICHARD F. HASKAYNE, O.C., F.C.A.[3,4] . .<br>Calgary, Alberta | 1992 | Chairman of the Board<br>TransCanada Corporation<br>*(Pipelines and energy services)* |
| DALE A. LUCAS[1,5] . . . . . . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 1997 | Corporate Director |
| KEN F. MCCREADY[2,5,11] . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 1992 | President<br>K.F. McCready & Associates Ltd.<br>*(Sustainable energy development consulting company)* |
| GWYN MORGAN . . . . . . . . . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 1993 | President & Chief Executive Officer<br>EnCana Corporation |
| VALERIE A.A. NIELSEN[2,6] . . . . . . . . . . . . . .<br>Calgary, Alberta | 1990 | Corporate Director |
| DAVID P. O'BRIEN[4,7,12] . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 1990 | Chairman<br>EnCana Corporation |

| Name and Municipality of Residence | Director Since[13] | Principal Occupation |
|---|---|---|
| JANE L. PEVERETT[1] . . . . . . . . . . . . . . . . . . . .<br>West Vancouver, British Columbia | 2003 | Chief Financial Officer<br>British Columbia Transmission Corporation<br>*(Electricity transmission)* |
| DENNIS A. SHARP[2,4] . . . . . . . . . . . . . . . . . . .<br>Calgary, Alberta | 1998 | Chairman & Chief Executive Officer<br>UTS Energy Corporation<br>*(Oil and natural gas company)* |
| JAMES M. STANFORD[1,3,6] . . . . . . . . . . . . . . .<br>Calgary, Alberta | 2001 | President<br>Stanford Resource Management Inc.<br>*(Investment management)* |

Notes:

(1) Audit Committee.

(2) Corporate Responsibility, Environment, Health and Safety Committee.

(3) Human Resources and Compensation Committee.

(4) Nominating and Corporate Governance Committee.

(5) Pension Committee.

(6) Reserves Committee.

(7) Ex-officio non-voting member of all other committees. As an ex-officio non-voting member, Mr. O'Brien attends as his schedule permits and may vote when necessary to achieve a quorum.

(8) Mr. Fatt was a director of Unitel Communications Inc. in 1995 when it made a filing pursuant to the *Companies' Creditors Arrangement Act* (Canada).

(9) Mr. Grandin was a director of Pegasus Gold Inc. in 1998 when that company filed voluntarily to reorganize under Chapter 11 of the Bankruptcy Code (United States). A liquidation plan for that company received court confirmation later that year.

(10) Mr. Harrison was a director of Gauntlet Energy Corporation in June 2003 when it filed for and was granted an order pursuant to the *Companies' Creditors Arrangement Act* (Canada). A plan of arrangement for that company received court confirmation later that year.

(11) Mr. McCready was a director of Colonia Corporation when the company was placed into receivership in October 2000. The company came out of receivership in October 2001.

(12) Mr. O'Brien resigned as a director of Air Canada on November 26, 2003. On April 1, 2003, Air Canada obtained an order from the Ontario Superior Court of Justice providing creditor protection under the *Companies' Creditors Arrangement Act* (Canada). Air Canada also made a concurrent petition under Section 304 of the U.S. Bankruptcy Code.

(13) Denotes the year each individual became a director of AEC or PanCanadian, if prior to the Merger, or EnCana, if after the Merger.

EnCana does not have an Executive Committee of its Board of Directors.

At the date of this annual information form, there are 16 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 16 nominees listed in the above table to serve until the close of the next annual meeting of shareholders, or until their respective successors are duly elected or appointed. Subject to mandatory retirement age restrictions which have been established by the Board of Directors, all of the directors shall be eligible for re-election.

**Executive Officers**

| Name and Municipality of Residence | Office |
|---|---|
| GWYN MORGAN<br>Calgary, Alberta | President & Chief Executive Officer |
| RANDALL K. ERESMAN<br>Calgary, Alberta | Executive Vice-President & Chief Operating Officer |
| ROGER J. BIEMANS<br>Denver, Colorado | Executive Vice-President |
| BRIAN C. FERGUSON<br>Calgary, Alberta | Executive Vice-President, Corporate Development |
| GERALD J. MACEY<br>Calgary, Alberta | Executive Vice-President |
| R. WILLIAM OLIVER<br>Calgary, Alberta | Executive Vice-President |
| GERARD J. PROTTI<br>Calgary, Alberta | Executive Vice-President, Corporate Relations |
| DRUDE RIMELL<br>Calgary, Alberta | Executive Vice-President, Corporate Services |
| JOHN D. WATSON<br>Calgary, Alberta | Executive Vice-President & Chief Financial Officer |

During the last five years, all of the directors and executive officers have served in various capacities with EnCana or its predecessor companies or have held the principal occupation indicated opposite their names except for the following:

Mr. Chernoff was President of Pacalta Resources Ltd. from 1988 to 1996 and Chairman of the Board of that company from 1988 to May 1999.

Mr. Daniel was President and Chief Operating Officer of Interprovincial Pipe Line Corporation from May 1994 to January 2001.

Mr. Fatt was Chairman and Chief Executive Officer of FHR Holdings Inc. (formerly Canadian Pacific Hotels & Resorts Inc.) from January 1998 to October 2001.

Mr. Grandin was President of PanCanadian Energy Corporation from October 2001 to April 2002. He was Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from December 1997 to October 2001.

Mr. O'Brien was Chairman and Chief Executive Officer of PanCanadian Energy Corporation from October 2001 to April 2002 and Chairman, President and Chief Executive Officer of Canadian Pacific Limited from May 1996 to October 2001.

Ms. Peverett was President of Union Gas Limited from April 2002 to May 2003, was President and Chief Executive Officer from April 2001 to April 2002, was Senior Vice President Sales & Marketing from June 2000 to April 2001, and was Chief Financial Officer from March 1999 to June 2000. She was Vice President Finance of Westcoast Energy Inc. from June 1998 to March 1999.

Mr. Stanford was President and Chief Executive Officer of Petro-Canada from January 1993 to January 2000.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 25, 2004, directly or indirectly, or exercised control or direction over an aggregate of 1,187,935 common shares representing 0.26 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 2,677,116 additional common shares.

Investors should be aware that some of the directors and officers of the Corporation are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of the Corporation.

## SUPPLEMENTAL OIL AND GAS INFORMATION

The following information is provided in addition to the information required under U.S. disclosure standards.

### *Reserve Quantities Information*

The following table sets forth estimates of gross proved reserves derived in the same manner as the net proved reserves continuity information on page 24 above. Gross proved reserves refer to the sum of (i) working interest reserves before deduction of royalty burdens payable and (ii) royalty interest reserves (lessor royalty and overriding royalty volumes derived from other working interest owners). The definitions of proved reserves, developed and undeveloped, are the same as those presented on page 24 above.

**Gross Proved Reserves (Before Royalties)[1]**
**Constant Pricing**

| | Natural Gas (billions of cubic feet) | | | | Crude Oil and Natural Gas Liquids (millions of barrels) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Canada | United States | United Kingdom | Total | Canada | United States | Ecuador | United Kingdom | Total |
| 2001 — End of Year | | | | | | | | | |
| Developed | 3,009 | 226 | 7 | 3,242 | 268.9 | 20.4 | — | 21.6 | 310.9 |
| Undeveloped | 586 | 69 | — | 655 | 47.4 | 3.7 | — | — | 51.1 |
| Total | 3,595 | 295 | 7 | 3,897 | 316.3 | 24.1 | — | 21.6 | 362.0 |
| 2002 — End of Year | | | | | | | | | |
| Developed | 4,715 | 1,808 | 9 | 6,532 | 336.0 | 27.3 | 142.7 | 8.3 | 514.3 |
| Undeveloped | 1,068 | 1,362 | 11 | 2,441 | 287.0 | 22.6 | 69.8 | 89.3 | 468.7 |
| Total | 5,783 | 3,170 | 20 | 8,973 | 623.0 | 49.9 | 212.5 | 97.6 | 983.0 |
| 2003 — End of Year | | | | | | | | | |
| Developed | 4,576 | 2,283 | 13 | 6,872 | 350.0 | 32.5 | 156.1 | 16.7 | 555.3 |
| Undeveloped | 1,412 | 1,582 | 13 | 3,007 | 392.2 | 18.9 | 62.3 | 107.8 | 581.2 |
| Total | 5,988 | 3,865 | 26 | 9,879 | 742.2 | 51.4 | 218.4 | 124.5 | 1,136.5 |

Notes:

(1) Includes EnCana's royalty interest volumes. At December 31, 2003, these volumes amounted to approximately 183 billion cubic feet of natural gas and 14.8 million barrels of liquids in Canada. At December 31, 2002, these volumes were approximately 225 billion cubic feet of natural gas and 18.7 million barrels of liquids in Canada. At December 31, 2001, these volumes were approximately 336 billion cubic feet of natural gas and 21.3 million barrels of liquids in Canada.

***Daily Sales Volume and Per-Unit Results***

The following tables summarize gross and net daily sales volumes and per-unit results for EnCana on a quarterly basis for the periods indicated. *The information for 2002 is presented on the basis of combining the results for PanCanadian and AEC for the period prior to the Merger.*

| | Daily Sales Volumes — 2003 (Before Royalties)[1] | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 2,222 | 2,287 | 2,197 | 2,213 | 2,190 |
| Inventory withdrawal/(injection) | 35 | — | — | — | 141 |
| Canada Sales | 2,257 | 2,287 | 2,197 | 2,213 | 2,331 |
| United States | 735 | 813 | 757 | 698 | 672 |
| United Kingdom | 13 | 20 | 7 | 12 | 13 |
| **Total Produced Gas** | 3,005 | 3,120 | 2,961 | 2,923 | 3,016 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 60,316 | 62,284 | 59,708 | 59,012 | 60,246 |
| Heavy oil | 98,304 | 105,703 | 104,702 | 91,939 | 90,636 |
| Natural gas liquids | | | | | |
| Canada | 17,307 | 15,656 | 16,488 | 17,970 | 19,162 |
| United States | 11,269 | 11,486 | 11,487 | 12,329 | 9,751 |
| Total North America | 187,196 | 195,129 | 192,385 | 181,250 | 179,795 |
| Ecuador | | | | | |
| Production | 68,865 | 97,446 | 73,760 | 49,006 | 54,726 |
| Transferred to OCP Pipeline[2] | (4,437) | — | (6,805) | (2,816) | (8,191) |
| Over/(under) lifting | (1,905) | 6,192 | (13,412) | 3,385 | (3,771) |
| Ecuador Sales | 62,523 | 103,638 | 53,543 | 49,575 | 42,764 |
| United Kingdom | 10,128 | 15,067 | 5,813 | 9,019 | 10,610 |
| **Total Oil and Natural Gas Liquids** | 259,847 | 313,834 | 251,741 | 239,844 | 233,169 |
| **Total** ***(barrels of oil equivalent/day)*** | 760,680 | 833,834 | 745,241 | 727,011 | 735,836 |
| Syncrude | 7,697 | — | 3,401 | 7,383 | 20,272 |

Notes:

(1) Includes EnCana's royalty interest volumes.

(2) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

| | Daily Sales Volumes — 2002 (Before Royalties)[1] | | | | |
|---|---|---|---|---|---|
| | Year[2] | Q4 | Q3 | Q2 | Q1[2] |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 2,220 | 2,226 | 2,209 | 2,262 | 2,188 |
| Inventory withdrawal/(injection) | 28 | 149 | (80) | (118) | 160 |
| Canada Sales | 2,248 | 2,375 | 2,129 | 2,144 | 2,348 |
| United States | 500 | 654 | 550 | 428 | 365 |
| United Kingdom | 10 | 8 | 9 | 8 | 11 |
| **Total Produced Gas** | 2,758 | 3,037 | 2,688 | 2,580 | 2,724 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 66,333 | 62,369 | 65,345 | 66,807 | 70,914 |
| Heavy oil | 78,029 | 86,019 | 80,797 | 76,233 | 68,846 |
| Natural gas liquids | | | | | |
| Canada | 17,399 | 19,121 | 16,225 | 16,796 | 17,448 |
| United States | 7,961 | 11,558 | 6,702 | 7,115 | 6,427 |
| Total North America | 169,722 | 179,067 | 169,069 | 166,951 | 163,635 |
| Ecuador | | | | | |
| Production | 50,980 | 48,486 | 52,344 | 52,744 | 50,351 |
| Over/(under) lifting | 101 | 1,448 | 3,235 | 7,120 | (11,577) |
| Ecuador Sales | 51,081 | 49,934 | 55,579 | 59,864 | 38,774 |
| United Kingdom | 10,528 | 7,786 | 9,538 | 11,966 | 12,889 |
| **Total Oil and Natural Gas Liquids** | 231,331 | 236,787 | 234,186 | 238,781 | 215,298 |
| **Total** ***(barrels of oil equivalent/day)*** | 690,998 | 742,954 | 682,186 | 668,781 | 669,298 |
| Syncrude | 31,556 | 34,261 | 36,039 | 24,295 | 31,548 |

| | Daily Sales Volumes — 2002 (After Royalties)[1] | | | | |
|---|---|---|---|---|---|
| | Year[2] | Q4 | Q3 | Q2 | Q1[2] |
| **SALES** | | | | | |
| **Produced Gas** ***(million cubic feet/day)*** | | | | | |
| Canada | | | | | |
| Production | 1,953 | 1,943 | 1,959 | 1,980 | 1,930 |
| Inventory withdrawal/(injection) | 22 | 117 | (51) | (90) | 113 |
| Canada Sales | 1,975 | 2,060 | 1,908 | 1,890 | 2,043 |
| United States | 395 | 516 | 423 | 345 | 295 |
| United Kingdom | 10 | 8 | 9 | 8 | 11 |
| **Total Produced Gas** | 2,380 | 2,584 | 2,340 | 2,243 | 2,349 |
| **Oil and Natural Gas Liquids** ***(barrels/day)*** | | | | | |
| North America | | | | | |
| Light and medium oil | 59,222 | 55,265 | 58,321 | 58,885 | 64,531 |
| Heavy oil | 69,465 | 77,090 | 70,795 | 67,558 | 62,237 |
| Natural gas liquids | | | | | |
| Canada | 14,778 | 15,987 | 13,985 | 14,168 | 14,968 |
| United States | 7,019 | 10,016 | 5,901 | 6,368 | 5,757 |
| Total North America | 150,484 | 158,358 | 149,002 | 146,979 | 147,493 |
| Ecuador | | | | | |
| Production | 36,521 | 34,856 | 37,447 | 37,702 | 36,082 |
| Over/(under) lifting | 70 | 1,044 | 2,316 | 5,088 | (8,295) |
| Ecuador Sales | 36,591 | 35,900 | 39,763 | 42,790 | 27,787 |
| United Kingdom | 10,528 | 7,786 | 9,538 | 11,966 | 12,889 |
| **Total Oil and Natural Gas Liquids** | 197,603 | 202,044 | 198,303 | 201,735 | 188,169 |
| **Total** ***(barrels of oil equivalent/day)*** | 594,270 | 632,711 | 588,303 | 575,568 | 579,669 |
| Syncrude | 31,267 | 33,918 | 35,585 | 24,152 | 31,337 |

Notes:

(1) Includes EnCana's royalty interest volumes.

(2) Includes AEC volumes for the first quarter of 2002.

**The following per-unit results are presented in Canadian dollars.** The results are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been provided as additional information.

| | Per-Unit Results (C$) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2003 | | | | | 2002 | | |
| | Year | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 |
| Produced Gas — Canada (C$/Mcf) | | | | | | | | |
| Price, net of transportation and selling | 6.34 | 5.25 | 5.80 | 6.43 | 7.85 | 5.17 | 3.24 | 4.23 |
| Royalties[1] | 0.92 | 0.78 | 0.85 | 1.05 | 1.00 | 0.77 | 0.39 | 0.65 |
| Operating expenses | 0.57 | 0.51 | 0.58 | 0.54 | 0.63 | 0.59 | 0.58 | 0.54 |
| Netback excluding hedge | 4.85 | 3.96 | 4.37 | 4.84 | 6.22 | 3.81 | 2.27 | 3.04 |
| Financial hedge | (0.18) | 0.29 | (0.04) | (0.31) | (0.65) | (0.08) | 0.29 | (0.12) |
| Netback including hedge | 4.67 | 4.25 | 4.33 | 4.53 | 5.57 | 3.73 | 2.56 | 2.92 |
| Produced Gas — United States (C$/Mcf) | | | | | | | | |
| Price, net of transportation and selling | 6.28 | 5.54 | 6.11 | 6.13 | 7.55 | 4.74 | 3.16 | 3.56 |
| Royalties[1] | 1.79 | 1.52 | 1.73 | 1.74 | 2.23 | 1.42 | 0.99 | 0.98 |
| Operating expenses | 0.31 | 0.30 | 0.36 | 0.33 | 0.25 | 0.28 | 0.34 | 0.38 |
| Netback excluding hedge | 4.18 | 3.72 | 4.02 | 4.06 | 5.07 | 3.04 | 1.83 | 2.20 |
| Financial hedge | 0.04 | (0.13) | (0.17) | (0.24) | 0.80 | 0.42 | 0.57 | 0.06 |
| Netback including hedge | 4.22 | 3.59 | 3.85 | 3.82 | 5.87 | 3.46 | 2.40 | 2.26 |
| Produced Gas — Total North America (C$/Mcf) | | | | | | | | |
| Price, net of transportation and selling | 6.32 | 5.33 | 5.88 | 6.36 | 7.78 | 5.08 | 3.21 | 4.11 |
| Royalties[1] | 1.13 | 0.98 | 1.08 | 1.22 | 1.28 | 0.91 | 0.51 | 0.70 |
| Operating expenses | 0.50 | 0.45 | 0.53 | 0.49 | 0.54 | 0.52 | 0.53 | 0.52 |
| Netback excluding hedge | 4.69 | 3.90 | 4.27 | 4.65 | 5.96 | 3.65 | 2.17 | 2.89 |
| Financial hedge | (0.13) | 0.18 | (0.07) | (0.30) | (0.33) | 0.03 | 0.35 | (0.09) |
| Netback including hedge | 4.56 | 4.08 | 4.20 | 4.35 | 5.63 | 3.68 | 2.52 | 2.80 |
| Light and Medium Oil — North America (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 35.33 | 31.84 | 32.59 | 35.78 | 41.36 | 36.36 | 36.01 | 35.35 |
| Royalties[1,2] | 4.42 | 3.78 | 3.59 | 4.56 | 5.82 | 4.81 | 4.56 | 4.36 |
| Operating expenses | 7.63 | 7.29 | 8.02 | 7.54 | 7.68 | 7.16 | 6.58 | 7.25 |
| Netback excluding hedge | 23.28 | 20.77 | 20.98 | 23.68 | 27.86 | 24.39 | 24.87 | 23.74 |
| Financial hedge | (5.21) | (4.47) | (4.08) | (3.52) | (8.83) | (1.26) | (0.89) | (1.59) |
| Netback including hedge | 18.07 | 16.30 | 16.90 | 20.16 | 19.03 | 23.13 | 23.98 | 22.15 |
| Heavy Oil — North America (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 25.74 | 22.21 | 23.96 | 25.99 | 31.80 | 25.81 | 29.44 | 26.85 |
| Royalties[1,2] | 2.92 | 2.32 | 2.45 | 3.10 | 3.99 | 3.43 | 3.67 | 3.09 |
| Operating expenses | 7.05 | 5.94 | 7.38 | 7.52 | 7.52 | 5.64 | 6.71 | 5.87 |
| Netback excluding hedge | 15.77 | 13.95 | 14.13 | 15.37 | 20.29 | 16.74 | 19.06 | 17.89 |
| Financial hedge | (4.95) | (4.52) | (3.95) | (2.80) | (8.83) | (1.18) | (0.89) | (0.76) |
| Netback including hedge | 10.82 | 9.43 | 10.18 | 12.57 | 11.46 | 15.56 | 18.17 | 17.13 |
| Total Oil — North America (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 29.39 | 25.78 | 27.09 | 29.80 | 35.61 | 30.26 | 32.38 | 30.82 |
| Royalties[1,2] | 3.49 | 2.86 | 2.87 | 3.67 | 4.72 | 4.01 | 4.07 | 3.68 |
| Operating expenses | 7.27 | 6.44 | 7.61 | 7.53 | 7.59 | 6.28 | 6.66 | 6.51 |
| Netback excluding hedge | 18.63 | 16.48 | 16.61 | 18.60 | 23.30 | 19.97 | 21.65 | 20.63 |
| Financial hedge | (5.05) | (4.50) | (4.00) | (3.08) | (8.83) | (1.22) | (0.89) | (1.15) |
| Netback including hedge | 13.58 | 11.98 | 12.61 | 15.52 | 14.47 | 18.75 | 20.76 | 19.48 |
| Natural Gas Liquids — Canada (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 33.97 | 32.90 | 31.65 | 29.40 | 41.25 | 34.15 | 27.51 | 27.07 |
| Royalties | 6.01 | 4.85 | 5.24 | 5.28 | 8.33 | 5.60 | 3.80 | 4.24 |
| Netback | 27.96 | 28.05 | 26.41 | 24.12 | 32.92 | 28.55 | 23.71 | 22.83 |

| | Per-Unit Results (C$) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2003 | | | | | 2002 | | |
| | Year | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 |
| Natural Gas Liquids — United States (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 37.83 | 35.11 | 35.18 | 34.45 | 48.59 | 39.47 | 40.07 | 36.65 |
| Royalties(1) | 8.98 | 9.05 | 9.02 | 7.37 | 10.92 | 6.54 | 6.60 | 5.75 |
| Netback | 28.85 | 26.06 | 26.16 | 27.08 | 37.67 | 32.93 | 33.47 | 30.90 |
| Natural Gas Liquids — Total North America (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 35.49 | 33.83 | 33.10 | 31.45 | 43.73 | 36.15 | 31.18 | 29.92 |
| Royalties(1) | 7.18 | 6.63 | 6.79 | 6.13 | 9.21 | 5.95 | 4.62 | 4.69 |
| Netback | 28.31 | 27.20 | 26.31 | 25.32 | 34.52 | 30.20 | 26.56 | 25.23 |
| Total Liquids — Canada (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 29.84 | 26.38 | 27.51 | 29.77 | 36.25 | 30.69 | 31.89 | 30.42 |
| Royalties(1) | 3.74 | 3.03 | 3.08 | 3.84 | 5.13 | 4.19 | 4.04 | 3.74 |
| Operating expenses | 6.56 | 5.89 | 6.92 | 6.73 | 6.73 | 5.56 | 5.99 | 5.83 |
| Netback excluding hedge | 19.54 | 17.46 | 17.51 | 19.20 | 24.39 | 20.94 | 21.86 | 20.85 |
| Financial hedge | (4.55) | (4.11) | (3.64) | (2.75) | (7.83) | (1.08) | (0.80) | (1.02) |
| Netback including hedge | 14.99 | 13.35 | 13.87 | 16.45 | 16.56 | 19.86 | 21.06 | 19.83 |
| Ecuador Oil (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 31.13 | 28.16 | 28.40 | 29.50 | 43.90 | 35.38 | 33.59 | 31.67 |
| Royalties(1) | 10.36 | 8.82 | 8.59 | 9.78 | 17.12 | 12.29 | 12.51 | 10.76 |
| Operating expenses | 4.97 | 4.53 | 4.45 | 5.91 | 5.63 | 6.04 | 4.60 | 5.70 |
| Netback excluding hedge | 15.80 | 14.81 | 15.36 | 13.81 | 21.15 | 17.05 | 16.48 | 15.21 |
| Financial hedge | — | — | — | — | — | — | — | (0.04) |
| Netback including hedge | 15.80 | 14.81 | 15.36 | 13.81 | 21.15 | 17.05 | 16.48 | 15.17 |
| United Kingdom Oil (C$/bbl) | | | | | | | | |
| Price, net of transportation and selling | 36.50 | 33.36 | 35.79 | 35.39 | 42.53 | 37.99 | 39.30 | 37.78 |
| Operating expenses | 6.99 | 8.20 | 9.03 | 6.56 | 4.41 | 11.10 | 5.71 | 3.12 |
| Netback | 29.51 | 25.16 | 26.76 | 28.83 | 38.12 | 26.89 | 33.59 | 34.66 |

Notes:

(1) Includes production and mineral taxes.

(2) Excludes impact of amendments, made in Q3 2003, related to prior years which reduced royalties by C$21 million.

## ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of EnCana's securities, and options to purchase securities, is contained in the Information Circular for EnCana's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in EnCana's audited consolidated financial statements for the year ended December 31, 2003.

When the securities of EnCana are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities, EnCana will, upon request to the Corporate Secretary as listed below, provide to any person the following information:

(i) one copy of the Corporation's annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the annual information form,

(ii) one copy of the audited consolidated financial statements of EnCana for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of EnCana that have been filed, if any, for any period after the end of its most recently completed financial year,

(iii) one copy of the information circular of EnCana in respect of its most recent annual meeting of shareholders that involved the election of directors, and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above.

At any other time, EnCana will, upon request to the Corporate Secretary as listed below, provide to any person one copy of any of the documents referred to in (i), (ii) and (iii) above, provided EnCana may require the payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of EnCana.

For additional copies of this annual information form or any of the materials listed in the preceding paragraphs, please contact:

Kerry D. Dyte
General Counsel
and Corporate Secretary
EnCana Corporation
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5

Corporate Development Department:
Phone: 403-645-2000
Fax: 403-645-4617

## APPENDIX A

### Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of EnCana Corporation (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2003. The reserves data consist of the following:

   (i) estimated proved oil and gas reserve quantities as at December 31, 2003 using constant prices and costs; and

   (ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserve quantities.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements of the U.S. Securities and Exchange Commission ("SEC Requirements").

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions outlined above.

4. The following table sets forth both the estimated proved reserve quantities (after royalties) and related estimates of future net cash flows (before deduction of income taxes) assuming constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2003:

| Evaluator and Preparation Date of Report | Reserves Location | Estimated Proved Reserve Quantities After Royalty | | Related Estimates of Future Net Cash Flow |
|---|---|---|---|---|
| | | Gas | Liquids | BTax, 10% discount rate |
| | | (Bcf) | (MMbbl) | ($USMM) |
| McDaniel & Associates Consultants Ltd. January 10, 2004 | Canada | 3,217 | 451.4 | 8,719 |
| Gilbert Laustsen Jung Associates Ltd. January 23, 2004 | Canada | 2,019 | 136.1 | 4,808 |
| Ryder Scott Company January 5, 2004 | Canada | 20 | 42.0 | 261 |
| Netherland, Sewell & Associates, Inc. January 6, 2004 | United States | 3,130 | 41.6 | 7,304 |
| Ryder Scott Company January 5, 2004 | Ecuador | | 161.7 | 1,894 |
| DeGolyer and MacNaughton January 2, 2004 | UK - North Sea | 26 | 124.4 | 814 |
| **Totals** | | 8,411 | 957.2 | 23,800 |

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC requirements.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Reserves are estimates only, and not exact quantities. In addition, as the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta, Canada

(signed) Netherland, Sewell & Associates, Inc.
Dallas, Texas, U.S.A.

(signed) DeGolyer and MacNaughton
Dallas, Texas, U.S.A.

(signed) Ryder Scott Company
Houston, Texas, U.S.A./Calgary, Alberta, Canada

February 9, 2004

## APPENDIX B

### Report of Management and Directors on Reserves Data and Other Information

Management and directors of EnCana Corporation (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. In the case of the Corporation, the regulatory requirements are covered under NI 51-101 as amended by an MRRS Decision Document dated December 16, 2003, and require disclosure of information contemplated by, and consistent with, US Disclosure Requirements and US Disclosure Practices (as defined in the Decision Document). Required information includes reserves data, which consist of the following:

(i) proved oil and gas reserve quantities estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserve quantities.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators dated February 9, 2004 (the "IQRE Report"), highlighting the standards they followed and their results, accompanies this Report.

The Reserves Committee of the board of directors (the "Board of Directors") of the Corporation, which Committee is comprised exclusively of non-management and unrelated directors, has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions placed by management affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data as outlined in the IQRE Report with management and each of the independent qualified reserves evaluators.

The Board of Directors has reviewed the standardized measure calculation with respect to the Corporation's proved oil and gas reserve quantities. The Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved:

(a) the content and filing with securities regulatory authorities of the proved oil and gas reserve quantities, related standardized measure calculation and other oil and gas activity information, contained in the annual information form of the Corporation accompanying this Report;

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

Reserves data are estimates only, and are not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) Gwyn Morgan
President & Chief Executive Officer

(signed) Brian C. Ferguson
Executive Vice-President, Corporate Development

(signed) David P. O'Brien
Director and Chairman of the Board

(signed) James M. Stanford
Director and Chairman of the Reserves Committee

February 25, 2004

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