ENCANA CORP
Form 40FR12B
February 28, 2003

U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

[ ] Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2002

Commission file number 1-15226

ENCANA CORPORATION

(Exact name of registrant as specified in its charter)

Canada	**1311**	**Not applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S. Employer Identification Number (if Applicable))

1800-855 2nd Street, S.W., P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5
(403) 645-2000
(Address and Telephone Number of Registrant s Principal Executive Offices)

c/o CT Corporation System, 111 8th Avenue, New York, NY 10011

(212) 894-8940
(Name, Address (Including Zip Code) and Telephone Number
(Including Area Code) of Agent For Service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common Shares	New York Stock Exchange
Preferred Securities	New York Stock Exchange

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

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: Debt Securities

For annual reports, indicate by check mark the information filed with this Form:

[X] Annual Information Form [X] Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Common Shares, without par value, outstanding at December 31, 2002: 478,383,618

Indicate by check mark whether the registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes [ ] No [X]

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

Yes [X] No [ ]

Form 40-F Table of Contents

Document

1. Annual Information Form of EnCana Corporation (the   Company   ) for the fiscal year ended December 31, 2002.

2. Management   s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2002.

3. Consolidated Financial Statements for the fiscal year ended December 31, 2002 (*Note 23 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP))*.

4. Controls and Procedures.

5. Exhibits.

ANNUAL INFORMATION FORM

February 19, 2003

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All dollar amounts in this Annual Information Form are Canadian dollars, unless otherwise specified.

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

This Annual Information Form (the AIF) 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 AIF include, but are not limited to, statements with respect to: the cost, timing and successful completion of construction of the Oleoducto de Crudos Pesados pipeline, the sources of payment and allocation of such cost and EnCana s share thereof, 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, oil and natural gas prices, the cost and timing of completion of the expansion at one of the Empress natural gas liquids extraction plants, the timing of completion of the Wild Goose Gas Storage Facility and Foster Creek expansions, the timing of completion of the Countess Gas Storage Facility, the timing and extent of operations at Christina Lake, storage capacity, the level of material expenditures for compliance with environmental regulations, site restoration costs, the Petrovera Partnership s strategy, the timing and successful completion of the Syncrude sale, the timing of applicable regulatory approvals, the timing and completion of other acquisitions, future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves 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 AIF 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 inherent in EnCana s marketing operations, imprecision of reserves estimates, EnCana s ability to replace and expand oil and natural gas reserves, EnCana s ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain 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 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 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, political and economic conditions in the countries in which EnCana operates including Ecuador, 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 or resources are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this AIF, which is as of the date hereof, and EnCana undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

ITEM 2: CORPORATE STRUCTURE

Name and Incorporation

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.

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 *Canada Business Corporations Act* (CBCA) on June 26, 2001 in order to participate in the reorganization (the CPL 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, 2002:

Subsidiaries & Partnerships	Percent Owned(1)	Jurisdiction of Incorporation, Continuance or Formation
Alberta Energy Company Ltd.(2)	100	Canada
EnCana West Ltd.	100	Alberta
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Energy Holdings Inc.	100	Delaware
EnCana Oil & Gas Partnership	100	Alberta
EnCana Midstream & Marketing(3)	100	Alberta
Marquest Limited Partnership	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Amalgamated with EnCana on January 1, 2003.

(3) Formerly EnCana Resources.

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, 2002.

In the following Items, 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 and 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.

ITEM 3: GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is the largest Canadian independent oil and natural gas exploration and production company, based on landholdings and production at December 31, 2002. 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 has interests in midstream operations and assets, including natural gas storage and processing facilities and pipelines. EnCana explores for, produces and markets natural gas, crude oil and natural gas liquids (NGLs) in Canada and the United States. EnCana is also engaged in exploration and production activities internationally including production from Ecuador and the U.K. central North Sea.

Upon the 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. The following describes the significant transactions and events in the last three years in the businesses that are now conducted in those divisions.

Onshore North America

The Onshore North America division manages EnCana s oil and natural gas exploration, development and production activity in EnCana s two largest core growth platforms, Western Canada and the U.S. Rockies.

In Western Canada, one of EnCana s primary focuses is on growing natural gas volumes. EnCana pursues natural gas in shallow and deep horizons primarily in Alberta and British Columbia and has had several discoveries over the last three years.

Exploration for coalbed methane (CBM) natural gas derived from coal seams over the last three years has led to the development of CBM pilot projects located in the Palliser Block of southern Alberta and in Elk Valley and Grizzly Valley in eastern British Columbia.

EnCana is also focused on crude oil development projects in Western Canada including thermal operations at Foster Creek and Christina Lake in northeast Alberta. Commercial production commenced at Foster Creek in the fourth quarter of 2001 and pilot production began at Christina Lake at the end of the third quarter of 2002. At Weyburn, Saskatchewan, the first phase of the carbon dioxide (CO_2) miscible flood project went into operation in late 2000, after completion of a pipeline to deliver CO_2 to the project.

In February 2003, EnCana agreed to sell a 10 percent interest in the Syncrude Joint Venture (Syncrude) to Canadian Oil Sands Limited (COS) for approximately $1.07 billion. The Corporation has also granted COS an option to purchase, on similar terms and prior to year-end 2003, EnCana s remaining 3.75 percent share and an overriding royalty. If exercised by COS, the option would generate additional proceeds of approximately $417 million. Each transaction is subject to regulatory approval, the completion of other closing conditions and normal closing adjustments. The sale of the 10 percent interest in Syncrude is expected to be completed on or about February 28, 2003.

The development of the U.S. Rockies as a core area began with an acquisition 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 approximately $1.1 billion. McMurry s principal producing properties are in the Jonah natural gas field located in the Green River Basin of southwest Wyoming.

In October 2000, EnCana increased its U.S. Rockies interests with the acquisition of the exploration, production, midstream and marketing divisions of The Montana Power Company (Montana Power) for approximately $689 million. The Montana Power U.S. producing properties are located in Colorado, Wyoming and Montana.

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 $328 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

Company, 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 Company was sold for proceeds of approximately $568 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 $420 million. The principal producing properties acquired from the El Paso subsidiaries are 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 $550 million. The principal producing properties acquired from the Williams subsidiary are in the Jonah natural gas field in southwest Wyoming.

Offshore & International Operations

EnCana s Offshore & International Operations division develops the reserves associated with offshore and international discoveries to establish new production operations and enhances these operations through acquisitions and ongoing asset portfolio upgrades. Regions with existing or potential major developments and/or production operations include: Ecuador, the U.K. central North Sea, the East Coast of Canada and the Gulf of Mexico.

EnCana entered Ecuador in 1999 through the acquisition of Pacalta Resources Ltd. for approximately $1.0 billion, and is involved in oil exploration, development and production primarily in the Oriente Basin. The Corporation increased its activity in Ecuador through a farm-in in the fourth quarter of 2000 and through an acquisition in January 2003 where EnCana acquired additional reserves and production from Vintage Petroleum, Inc. for approximately US$137.4 million (including working capital and subject to post-closing adjustments).

In the first quarter of 2000, EnCana completed the purchase of 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively, in the U.K. central North Sea, for approximately $259 million.

In the spring of 2001, the Corporation made a significant crude oil discovery in the U.K. central North Sea at Buzzard.

In February 2003, EnCana requested an adjournment of the regulatory approval process for its 1999 Deep Panuke gas discovery offshore Nova Scotia on the East Coast of Canada. EnCana has initiated a comprehensive review of its Deep Panuke project in order to strengthen anticipated project economics.

In the Gulf of Mexico, EnCana participated in the Llano oil discovery in 1998. Since then, three follow-up wells have been drilled.

Offshore & New Ventures Exploration

EnCana s Offshore & New Ventures Exploration division searches for reserves on which to build new growth platforms in international offshore and onshore basins with the aim of generating additional medium and long-term growth. The Corporation s offshore exploration efforts have been successful in the U.K. central North Sea (Buzzard discovery), in the Gulf of Mexico (Llano and Tahiti discoveries) and on the East Coast of Canada (Deep Panuke discovery).

The U.K. central North Sea became an exploration area for EnCana in 1996 through a multi-block farm-in agreement with an existing operator. The Corporation has continued to focus its activities in the central North Sea by accumulating prospects through participation in licensing rounds, trades and farm-ins.

The Corporation has been increasing its landholdings in the Gulf of Mexico through lease sales, farm-ins, exchanges and acquisitions. Various exploration wells have been drilled over the last three years, with participation in a significant oil discovery at Tahiti in 2002.

The Corporation has developed one of the largest land positions offshore the East Coast of Canada. Since the Deep Panuke discovery, EnCana has conducted an active exploration program, on its own and with partners, and participated in a discovery at the Annapolis prospect which requires further drilling to determine commerciality.

EnCana is seeking new opportunities beyond the Corporation s core geographic areas and is actively exploring potential opportunities in Canada s Mackenzie Delta, Alaska, Australia, Brazil, Central and West Africa, the Middle East and Greenland.

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Midstream & Marketing

EnCana s midstream activities are primarily comprised of three business units: Gas Storage, Natural Gas Liquids and Power.

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

In July 2002, after a strategic review of the Corporation s assets, EnCana commenced seeking buyers for its indirect 70 percent interest in the Cold Lake Pipeline System (Cold Lake) and its indirect 100 percent interest in the Express Pipeline System (Express). In January 2003, EnCana completed the sale of its interest in Cold Lake for approximately $425 million (subject to post-closing adjustments). The Corporation has retained oil transportation capacity on Cold Lake for its production through its existing long-term contracts. The sale of the Express interest was also completed in January 2003 for approximately $1.175 billion (subject to post-closing adjustments), which includes the assumption of approximately $599 million in debt by the purchaser. EnCana has retained oil transportation capacity on Express through its existing long-term contracts.

EnCana continues to have interests in pipelines in South America. EnCana is part of a consortium that is building the Oleoducto de Crudos Pesados (OCP) pipeline in Ecuador. As of January 2003, the pipeline was approximately 85 percent complete and upon completion, currently projected for the third quarter of 2003, it is expected that the pipeline will have a capacity of approximately 450,000 barrels of oil per day. EnCana has an indirect 31.4 percent equity interest in the project.

EnCana s marketing business unit directly sells the majority of the Corporation s production and manages energy commodity risk. EnCana Crude Oil marketing supplies a number of third parties with marketing services for a fee. EnCana Marketing will also purchase and take delivery of product from others and deliver product to customers under transportation arrangements not utilized for the Corporation s own production.

Following the Merger, EnCana determined to discontinue the Houston-based merchant energy operation of its predecessor company, PanCanadian. As at December 31, 2002, the winding-down of this operation had been substantially completed.

ITEM 4: NARRATIVE DESCRIPTION OF THE BUSINESS

In this Item, unless otherwise specified, all statistical information and descriptions of operational results for EnCana for 2002 and prior periods are presented on the basis of combining the results for PanCanadian and AEC for periods prior to the Merger.

EnCana s business is conducted in two main industry groups: the Upstream group and the Midstream & Marketing group. The Upstream group is comprised of the Onshore North America, Offshore & International Operations and Offshore & New Ventures Exploration divisions.

UPSTREAM

EnCana pursues exploration and development of oil and natural gas in the plains area of the Western Canada Sedimentary Basin; medium to deep natural gas and NGLs in northeast British Columbia and the western Alberta foothills; thermal recovery of oil at Foster Creek and Christina Lake in northeast Alberta; and deep, tight, natural gas in the U.S. Rockies. EnCana has commenced commercial CBM development in southern Alberta and is evaluating the potential for CBM development in eastern British Columbia. Internationally, activities are primarily focused on exploration and development in the Oriente Basin in Ecuador, in the U.K. central North Sea, on the East Coast of Canada and in the Gulf of Mexico. New Ventures groups are exploring for potential new growth platforms on the East Coast of Canada, in Canada s Mackenzie Delta, and in the Gulf of Mexico, Alaska, Australia, Brazil, Central and West Africa, the Middle East and Greenland.

Onshore North America

Western Canada

Within Western Canada, EnCana has operations in four regions. The Foothills region targets medium to deep natural gas in northeast British Columbia and the western Alberta foothills. The Central Plains and Southern Plains regions focus on natural gas and oil exploration and development in the plains areas of the Western Canada Sedimentary Basin. The Oilsands region focuses on oil development, including thermal recovery projects at Foster Creek and Christina Lake using steam-assisted gravity drainage (SAGD) technology and a CO_2 miscible flood project at Weyburn.

Western Canada is EnCana s principal foundation, largely from its industry leading land position of approximately 25.4 million gross acres (approximately 21.6 million net acres, of which approximately 15.3 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.

EnCana s 2003 capital investment in core programs for natural gas projects in Western Canada is anticipated to be approximately $2 billion with approximately $200 million directed to exploration and approximately $1.8 billion to development. The drilling of approximately 4,000 gross natural gas wells is anticipated. Capital investment in 2003 for oil projects in Western Canada is forecast to be approximately $800 million, including approximately $160 million for SAGD projects and the drilling of approximately 700 gross oil wells. In 2003, EnCana also anticipates spending up to $120 million for its remaining share of Syncrude s projected capital expenditures, subject to the possible disposition of the balance of EnCana s interest in Syncrude.

Southern Plains Region

The major producing areas of the Southern Plains region are Brooks, Calgary and Suffield in Alberta.

Brooks

At December 31, 2002, EnCana held an average 95 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 130,000 net acres are undeveloped) in the Brooks area of Alberta, located east of Calgary. EnCana had interests in 7,063 gross producing natural gas wells (6,545 net wells) and 476 gross producing oil wells (472 net wells) at December 31, 2002. EnCana s production in 2002 averaged 426 million cubic feet per day of natural gas and 16,636 barrels per day of crude oil and NGLs (427 million cubic feet per day of natural gas and 17,000 per day of crude oil and NGLs in 2001).

Calgary

At December 31, 2002, 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 279,000 net acres are undeveloped) in the Calgary area. EnCana had interests in 1,920 gross producing natural gas wells (1,833 net wells) and 157 gross producing oil wells (150 net wells) at December 31, 2002. Average production for 2002 in this area was 349 million cubic feet per day of natural gas and 8,369 barrels per day of crude oil and NGLs (308 million cubic feet per day of natural gas and 6,938 barrels of crude oil and NGLs in 2001).

Suffield

At December 31, 2002, EnCana held an average 99 percent interest in the petroleum and natural gas rights to approximately 1.2 million gross acres (approximately 1.2 million net acres, of which approximately 284,000 net acres are undeveloped) in the productive Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeastern 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, 2002, there were 6,118 gross producing shallow natural gas wells (5,711 net wells). There were also 73 gross natural gas wells (73 net wells) producing from deeper formations. EnCana s 2002 production on the Suffield Block, including conserved solution natural gas, averaged 222 million cubic feet per day of dry, sweet natural gas (222 million cubic feet per day of natural gas in 2001).

EnCana operates and holds a 100 percent interest in properties along the west side of the Suffield Block, which produce conventional heavy oil. At December 31, 2002, there were 613 gross producing oil wells (613 net wells), of which 222 gross wells (222 net wells) were horizontal wells. In 2002, EnCana s Suffield area crude oil production averaged 28,733 barrels per day (23,250 barrels per day in 2001).

Central Plains Region

The major producing areas of the Central Plains region are the Primrose Block and Pelican Lake in Alberta, and areas in Alberta and Saskatchewan held through the Petrovera Resources partnership (the Petrovera Partnership).

Primrose Block

At December 31, 2002, EnCana held an average 97 percent interest in the petroleum and natural gas rights to approximately 872,000 gross acres (approximately 846,000 net acres, of which approximately 587,000 net acres are undeveloped) on the Primrose Block. At December 31, 2002, EnCana had interests in 481 gross natural gas wells (461 net wells) that were producing. In 2002, EnCana s production from Primrose averaged 232 million cubic feet per day of natural gas (230 million cubic feet per day of natural gas in 2001), all processed through 100 percent controlled and operated compression facilities.

Pelican Lake

At December 31, 2002, EnCana held a 100 percent interest in approximately 206,000 gross acres (approximately 206,000 net acres, of which approximately 149,000 net acres are undeveloped) of crude bitumen rights at Pelican Lake in north-central Alberta. EnCana also holds a 38 percent interest in a 70-mile, 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 production in 2002 from this area averaged 13,879 barrels per day of crude oil (14,469 barrels per day of crude oil in 2001) from interests in 458 gross oil wells (458 net wells) that were producing at December 31, 2002.

Petrovera

On May 1, 1999, EnCana and a predecessor company to ConocoPhillips Canada formed the Petrovera Partnership, that holds and manages certain heavy oil assets of the two companies in order to achieve operating and cost synergies. EnCana holds a 53.3 percent interest in the Petrovera Partnership through its contribution of certain conventional heavy oil production assets. The assets contributed by the partners are located in an approximate area between and including Bonnyville, Alberta and Kindersley, Saskatchewan. The partnership drilled 214 wells in 2002 and implemented a waterflood program on certain properties as a means of enhancing crude oil recovery. EnCana s share of production in 2002 averaged 18,269 barrels per day of crude oil (18,431 barrels per day of crude oil in 2001).

Foothills Region

The major producing areas of the Foothills region consist of Greater Sierra and Ladyfern in northeast British Columbia, and Sexsmith/ Hythe/Saddle Hills and Ferrier in northwestern Alberta.

Greater Sierra

In the Greater Sierra area of northeast British Columbia, at December 31, 2002, EnCana held an average 82 percent interest in the petroleum and natural gas rights to approximately 3.1 million gross acres (approximately 2.5 million net acres, of which approximately 2.2 million net acres are undeveloped). EnCana held an average 92 percent interest in eight production facilities in the area that were capable of processing approximately 246 million cubic feet per day of natural gas as at December 31, 2002. EnCana had interests in 351 gross producing natural gas wells (284 net wells) at December 31, 2002. EnCana s production in 2002 averaged 145 million cubic feet per day of natural gas and 668 barrels per day of NGLs (106 million cubic feet per day of natural gas and 372 barrels per day of NGLs in 2001).

Sexsmith/ Hythe/Saddle Hills

In the Sexsmith/ Hythe/Saddle Hills area, at December 31, 2002, EnCana held an average 75 percent interest in the petroleum and natural gas rights to approximately 563,000 gross acres (approximately 423,000 net acres, of which approximately 251,000 net acres are undeveloped), and had interests in 216 gross natural gas wells (175 net wells) and 57 gross oil wells (43 net wells) that were producing at December 31, 2002. EnCana s production in 2002 averaged 125 million cubic feet per day of natural gas and 4,028 barrels per day of crude oil and NGLs (123 million cubic feet per day of natural gas and 4,540 barrels per day of crude oil and NGLs in 2001).

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 operates and controls 100 percent of the Hythe natural gas plant, which has a capacity of approximately 170 million cubic feet per day. The Hythe natural gas plant and the Sexsmith sour natural gas plant are interconnected by pipeline to provide greater operating efficiencies. EnCana also owns and operates a 150-mile natural gas gathering system in the area.

Ladyfern

In the Ladyfern area of northeast British Columbia, at December 31, 2002, EnCana held an average 80 percent interest in the petroleum and natural gas rights to approximately 59,000 gross acres (approximately 47,000 net acres, of which 34,000 net acres are undeveloped). EnCana had interests in 15 gross natural gas wells (14 net wells) that were producing at December 31, 2002. EnCana s production in 2002 averaged 104 million cubic feet per day of natural gas (93 million cubic feet per day of natural gas in 2001).

Ferrier

In the Ferrier area of Alberta, at December 31, 2002, EnCana held an average 72 percent interest in the petroleum and natural gas rights to approximately 78,000 gross acres (approximately 56,000 net acres, of which approximately 39,000 net acres are undeveloped). EnCana had interests in 31 gross natural gas wells (22 net wells) that were producing at December 31, 2002. EnCana s production in 2002 averaged 48 million cubic feet per day of natural gas and 2,148 barrels per day of NGLs (21 million cubic feet per day of natural gas and 584 barrels per day of NGLs in 2001).

Oilsands Region

The major producing areas of the Oilsands region are the thermal operations at Foster Creek and Christina Lake, the integrated oilsands operation at Syncrude, all in northeast Alberta, and the enhanced recovery and miscible CO_2 flood operation at Weyburn in southeast Saskatchewan.

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 heavy crude oil are identified within the areas for which petroleum and natural gas lease rights are held. EnCana is

currently operating a heavy oil project in the Foster Creek area of the Primrose Block using SAGD technology. While commercial production from Foster Creek began in the fourth quarter of 2001, difficulties primarily involving the water re-use area of the plant were encountered, slowing production ramp-up. These difficulties were resolved during 2002 and the production rate at year-end 2002 was approximately 19,600 barrels per day, with average sales of 13,197 barrels per day of oil (2,648 barrels per day of oil in 2001). Construction of the Phase I Expansion of the Foster Creek project is expected to be completed by the fourth quarter of 2003. The Phase I Expansion is designed to increase production to an expected rate of approximately 30,000 barrels per day in 2004.

EnCana is building an 80 megawatt cogeneration facility in conjunction with its SAGD operation at Foster Creek. It is currently being commissioned with an expected start up in the spring of 2003. Approximately 20 percent of the power generated will be consumed within the current Foster Creek operation and the remaining power will be sold into the Alberta Power Pool. The steam generated will be used within the SAGD operation and will provide sufficient capacity for the Phase I Expansion.

Christina Lake

EnCana completed construction of a pilot SAGD facility at Christina Lake in the second quarter of 2002 and commenced production at the end of the third quarter of 2002. Production was approximately 3,300 barrels per day by year-end 2002.

Thermal Recovery Research and Development

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

One focus area is to reduce the reliance on steam in bitumen production. To this end, EnCana is piloting two technologies using solvents as part of the extraction process. The Solvent Aided Process, or SAP , mixes a small amount of solvent with steam to enhance recovery, while the Vapex process uses solvent in place of steam. After successfully piloting SAP at Senlac, Saskatchewan in 2002, EnCana will commence a pilot operation at Christina Lake in 2003. The Vapex pilot at Foster Creek commenced operation in 2002. 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.

Syncrude

In February 2003, EnCana agreed to sell a 10 percent interest in Syncrude to COS for approximately $1.07 billion. EnCana also granted COS an option to purchase the Corporation s remaining 3.75 percent interest and an overriding royalty.

Syncrude owns and engages Syncrude Canada Ltd. to operate the world s largest facility for the production of crude oil from oilsands. Oilsands are surface-mined and the bitumen is extracted from the sand and upgraded through a refining process to a light (32 API and low pour point), sweet (0.1 percent sulphur) crude oil known as Syncrude Sweet Blend. EnCana s share of Syncrude production averaged 31,556 barrels per day in 2002 (30,687 barrels per day in 2001).

Weyburn

EnCana has a 62 percent working interest, or a 50 percent economic interest, in the Weyburn field. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area with a CO_2 miscible flood project. EnCana increased its interest in the Weyburn field to approximately 69 percent in 1997 to ensure that the proposed CO_2 miscible flood project proceeded. EnCana sold a 7 percent working interest in the Weyburn Unit (the Unit) in July 2000, and an additional 11.7 percent net royalty interest in the Unit in October 2000. EnCana s sales volume from the Unit in 2002 averaged 13,003 barrels per day (11,982 barrels per day in 2001).

Coalbed Methane

EnCana has done extensive CBM evaluation work on fee lands in the Palliser Block of southern Alberta. By December 31, 2002, 100 CBM wells were tested, and the decision was made to start work on the first demonstration-scale commercial CBM project in Canada, for expected startup in early 2003. EnCana s first development is on a nine section block in the Entice area, with approximately 36 producing wells that are expected to provide a detailed analysis of the CBM potential on this tightly controlled EnCana fee land block. Initial production rates are expected to be in the

range of 30 to 250 thousand cubic feet per day per well. EnCana is currently considering additional development in 2003, with a decision expected in the first quarter.

EnCana has also been actively evaluating CBM in other areas of the Western Canada Sedimentary Basin. Focus areas include Elk Valley in southeast British Columbia, where EnCana has drilled 10 pilot test wells to evaluate coal deposits, and the Grizzly Valley area of northeast British Columbia.

U.S. Rockies

EnCana s operations in the U.S. Rockies area are 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 2003 capital investment in core programs in the U.S. Rockies is forecast to be approximately $700 million and includes the drilling of approximately 400 gross natural gas wells.

Jonah

At Jonah, EnCana held an average 95 percent interest in the petroleum and natural gas rights to approximately 60,000 gross acres (approximately 57,000 net acres, of which approximately 49,000 net acres are undeveloped) and had interests in 270 gross natural gas wells (223 net wells) that were producing at December 31, 2002. EnCana s production in 2002 averaged 341 million cubic feet per day of natural gas and 3,452 barrels per day of NGLs (181 million cubic feet per day of natural gas and 1,947 barrels per day of NGLs in 2001).

In July 2002, EnCana Oil & Gas (USA) Inc. completed the purchase of natural gas and associated NGLs production, reserves and acreage in the Jonah field in southwest Wyoming from Williams for approximately $550 million. This acquisition increased the Corporation s productive capacity from Jonah to in excess of 400 million cubic feet of natural gas equivalent per day.

Mamm Creek

At Mamm Creek, EnCana held an average 91 percent interest in the petroleum and natural gas rights to approximately 185,000 gross acres (approximately 168,000 net acres, of which approximately 132,000 net acres are undeveloped) and had interests in 306 gross natural gas wells (284 net wells) that were producing at December 31, 2002. EnCana s production in 2002 averaged 66 million cubic feet per day of natural gas and 461 barrels per day of NGLs (36 million cubic feet per day of natural gas and 345 barrels per day of NGLs in 2001).

In May 2002, EnCana expanded its production and landholding in the Piceance Basin with the purchase of natural gas and associated NGLs production, reserves and acreage in northwest Colorado for approximately $420 million. This acquisition complements the Corporation s existing Piceance Basin gas production at Mamm Creek and the surrounding area near Rifle, Colorado.

Offshore & International Operations

Ecuador

In Ecuador, EnCana is the largest private sector crude oil producer. Indirect, wholly owned subsidiaries of EnCana own two concessions in the Oriente Basin, which are known as the Tarapoa Block and Block 27. The Corporation has a 100 percent working interest in each concession. Both concessions are operated under participation contracts, which permit the subsidiaries to explore for and exploit oil at their sole risk and expense during the contract term. The participation contract for the Tarapoa Block has a primary term through to August 1, 2015 and the participation contract for Block 27 has a minimum producing period of 20 years from commencement of commercial production, which began in 2000.

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 two participation contracts which have primary terms through to July 2012 and July 2019.

In January 2003, EnCana acquired additional reserves and production in Ecuador from Vintage Petroleum, Inc. for approximately US$137.4 million (including working capital and subject to post-closing adjustments). The reserves are located in Blocks 14 and 17 as well as the Shiripuno Block in the Oriente Basin.

At December 31, 2002, 181 gross oil wells (146 net wells) were producing and 44 gross oil wells (40 net wells) were shut-in. EnCana s crude oil production in 2002 was 50,980 barrels per day (51,862 barrels per day in 2001).

With the completion of the OCP pipeline in 2003, the Corporation is targeting crude oil production to achieve between 60,000 and 80,000 barrels per day.

EnCana s 2003 capital investment in core programs in Ecuador is anticipated to be approximately $280 million, before additions associated with the acquisition from Vintage Petroleum, Inc.

U.K. Central North Sea

EnCana has a working interest in the Scott and Telford fields located in the U.K. central North Sea, 117 miles northeast of Aberdeen, Scotland. EnCana s working interest is 13.5 percent at Scott and 20.2 percent at Telford. Oil produced from both fields is processed at the Scott platform and transported via pipeline to the non-operated Forties pipeline system. The fields complement EnCana s existing exploratory acreage in the central North Sea. The Corporation acquired its interests in these fields in January 2000.

At December 31, 2002, there were 10 gross oil wells (3 net wells) producing. EnCana s crude oil and NGLs average production in 2002 was 10,175 barrels per day (11,376 barrels per day in 2001). In 2002, average natural gas production was approximately 10 million cubic feet per day (approximately nine million cubic feet per day in 2001).

Development work on the Buzzard discovery in the central North Sea is continuing with the awarding of the major engineering design contract. Evaluation of the appraisal drilling continues and EnCana plans to explore possible field extensions and adjacent geological structures. Initial production is anticipated in 2006. EnCana is the operator and owns 45 percent and 35 percent of the two blocks where Buzzard is located.

East Coast of Canada

Offshore Nova Scotia on the East Coast of Canada, EnCana has a 100 percent working interest in the Deep Panuke gas discovery approximately 200 kilometers off the coast of Nova Scotia in approximately 40 meters of water. A development plan application was filed in March of 2002. Infrastructure in this relatively under-explored basin will require expansion, the cost of which must be borne at least partly by the 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.

Gulf of Mexico

The Corporation holds a 22.5 percent working interest in the Llano discovery. Development work on Llano is continuing with production from phase one expected in 2004. Study work is underway to evaluate phase two development which would involve assessing and developing deeper reservoir zones.

Offshore & New Ventures Exploration

U.K. Central North Sea

EnCana has interests in 38 exploration blocks in the U.K. central North Sea, with a land position of approximately 1.0 million gross acres (approximately 352,000 net acres). Interests range from 8.2 percent to 100 percent. In addition, the Corporation continues to have interests in three deepwater frontier blocks in the Atlantic Margin west of Great Britain, comprising approximately 293,000 gross acres (approximately 62,000 net acres). In 2003, EnCana expects to drill five to seven wells.

East Coast of Canada

In 2002, the Corporation participated in the drilling of the Annapolis well offshore Nova Scotia, which encountered approximately 30 meters 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 interest in the discovery.

EnCana had an interest in approximately 4.9 million gross acres (approximately 3.1 million net acres) offshore Nova Scotia as at December 31, 2002. The Corporation also had an interest in approximately 4.3 million gross acres (approximately 2.8 million net acres) located offshore and onshore Newfoundland and onshore Labrador as at December 31, 2002. EnCana operates 21 of its 27 exploration licenses and has an average working interest of approximately 64 percent.

In 2003, the Corporation expects to drill up to six wells in Atlantic Canada.

Gulf of Mexico

EnCana owns a 25 percent interest in the Tahiti oil discovery, located in the deep water Green Canyon Block 640. Two appraisal wells are planned in early 2003 to evaluate this discovery.

EnCana has working interest acreage in over 160 blocks comprising approximately 937,000 gross acres (approximately 510,000 net acres) in the Gulf of Mexico, with options to add approximately 160 additional blocks. Such options were acquired through large regional farm-ins and the Corporation s ongoing land acquisition program.

Mackenzie Delta

EnCana has an approximate 38 percent interest in two exploration blocks comprising approximately 529,000 gross acres (approximately 201,000 net acres) in the Mackenzie Delta region of Canada s Northwest Territories. The Corporation is conducting seismic surveys on these blocks.

Alaska

EnCana has working interests in approximately 4.2 million gross acres (approximately 1.5 million net acres) of exploration lands in both offshore and onshore Alaska. At the end of 2002, the Corporation was in the process of drilling the offshore McCovey prospect. In February 2003, the Corporation plugged and abandoned the well bore.

Australia

EnCana has working interests in approximately 19.2 million gross acres (approximately 6.7 million net acres) offshore of Australia. The Corporation is focusing its exploration efforts in the Great Australian Bight region, south of Australia, and expects to drill an exploration well in the second quarter of 2003.

Brazil

EnCana has working interests in three blocks comprising approximately 1.9 million gross acres (approximately 1.5 million net acres) offshore of Brazil. In 2003, the Corporation plans to drill one well in the Campos basin and acquire seismic in the Equatorial Margin basin.

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). Activity over the next two years is expected to include extensive seismic surveys and exploratory well drilling.

The Corporation has a 40 percent working interest in the Keta Block comprising approximately 3.7 million gross acres (approximately 1.5 million net acres). EnCana plans to participate in a well offshore of Ghana in the Gulf of Guinea in 2003.

During 2002, EnCana closed its office and ended all operations in Libya.

Middle East

At the end of 2002, EnCana continued testing of a well in Qatar within the Block 2 exploration concession (approximately 2.8 million gross acres and approximately 1.1 million net acres), which includes most of onshore Qatar. EnCana assumed operatorship of this concession from Chevron Overseas Petroleum (Qatar) Limited (Chevron Overseas) in mid-2002, and took over the Chevron Overseas office in Doha.

The Corporation is also conducting a seismic survey on Block 60 (approximately 640,000 gross acres and approximately 250,000 net acres) in northern Yemen. In 2003, exploratory drilling operations are planned on Block 47 (approximately 1.9 million gross acres and approximately 987,000 net acres).

In February 2003, EnCana entered into an onshore exploration agreement with the Sultanate of Oman on Blocks 3 and 4, covering approximately 9.5 million gross acres, subject to the approval of the Sultan of Oman. Upon approval, the Corporation will have a 100 percent working interest in both blocks.

Greenland

During 2002, EnCana entered into an exploration agreement covering approximately 985,000 gross acres offshore of Greenland. At present, EnCana has a 100 percent working interest.

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.

Drilling Activity

The following tables summarize EnCana s 2002 and 2001 gross participation and net interest in wells drilled. Information for periods prior to the Merger represents the combined results for PanCanadian and AEC:

Exploration Wells Drilled 2002

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Onshore North America											
Canada	484	436	84	72	49	39	617	547	190	807	547
United States	16	15					16	15		16	15
Total Onshore North America	500	451	84	72	49	39	633	562	190	823	562
Offshore & International											
Australia					1		1			1	
Bahrain					1	1	1	1		1	1
East Coast	1				1	1	2	1		2	1
Ecuador			7	5			7	5		7	5
Gulf of Mexico			2	1	3	1	5	2		5	2
Qatar					2	1	2	1		2	1
United Kingdom			7	3	2	1	9	4		9	4
Total Offshore & International	1		16	9	10	5	27	14		27	14
Total	501	451	100	81	59	44	660	576	190	850	576

Development Wells Drilled 2002

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Onshore North America											
Canada	1,798	1,690	489	405	35	27	2,322	2,122	690	3,012	2,122
United States	323	276	3	3	1	1	327	280		327	280
Total Onshore North America	2,121	1,966	492	408	36	28	2,649	2,402	690	3,339	2,402
Offshore & International											
Ecuador			44	37	5	4	49	41		49	41
United Kingdom			2				2			2	

Total Offshore & International			46	37	5	4	51	41		51	41
Total	2,121	1,966	538	445	41	32	2,700	2,443	690	3,390	2,443

Exploration Wells Drilled 2001

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Onshore North America											
Canada	607	502	88	64	121	99	816	665	260	1,076	665
United States	25	17	1		3		29	17		29	17
Total Onshore North America	632	519	89	64	124	99	845	682	260	1,105	682
Offshore & International											
Australia					7	2	7	2		7	2
Congo					2		2			2	
East Coast					2	1	2	1		2	1
Ecuador			1	1			1	1		1	1
Gulf of Mexico					1		1			1	
United Kingdom			1		2	1	3	1		3	1
Total Offshore & International			2	1	14	4	16	5		16	5
Total	632	519	91	65	138	103	861	687	260	1,121	687

Development Wells Drilled 2001

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Onshore North America											
Canada	2,005	1,896	508	364	39	33	2,552	2,293	1,227	3,779	2,293
United States	227	159			3	1	230	160		230	160
Total Onshore North America	2,232	2,055	508	364	42	34	2,782	2,453	1,227	4,009	2,453
Offshore & International											
Ecuador			43	35			43	35		43	35
United Kingdom			4	1			4	1		4	1
Total Offshore & International			47	36			47	36		47	36
Total	2,232	2,055	555	400	42	34	2,829	2,489	1,227	4,056	2,489

Location of Wells

The following table summarizes EnCana s interest in producing wells and wells capable of producing as at December 31, 2002:

Location of Wells

As at December 31, 2002

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	20,692	19,525	4,845	4,128	25,537	23,653
British Columbia	475	397	1	1	476	398
Saskatchewan	241	141	2,678	1,202	2,919	1,343
Total Canada	21,408	20,063	7,524	5,331	28,932	25,394
Colorado	1,572	1,390	30	26	1,602	1,416
Montana	1,254	805	92	92	1,346	897
Texas	9	9			9	9
Utah	9	7			9	7
Wyoming	507	285			507	285
Total United States	3,351	2,496	122	118	3,473	2,614
Total North America	24,759	22,559	7,646	5,449	32,405	28,008
Ecuador			181	146	181	146
United Kingdom			10	3	10	3
Total International			191	149	191	149
Total	24,759	22,559	7,837	5,598	32,596	28,157

Note:

(1) EnCana has varying royalty interests in 7,426 oil wells and 11,008 natural gas wells which are producing or capable of producing.

Interest in Material Properties

The following table summarizes EnCana s total and undeveloped landholdings. Information as at December 31, 2001 represents the combined holdings for PanCanadian and AEC:

Landholdings, as at December 31

(thousands of acres)

	2002				2001			
	Total		Undeveloped		Total		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta								
Fee	5,332	5,173	2,795	2,771	5,190	5,019	3,053	3,013
Crown	11,875	9,974	8,113	6,871	12,428	10,234	8,687	7,302
Freehold	744	337	543	277	476	351	332	295
	17,951	15,484	11,451	9,919	18,094	15,604	12,072	10,610
British Columbia								
Crown	4,596	3,699	4,031	3,256	4,027	3,197	3,540	2,826
Saskatchewan								
Fee	493	477	481	467	482	471	472	462
Crown	1,676	1,320	1,345	1,112	1,229	1,135	1,004	947
Freehold	350	229	282	195	239	218	198	188
	2,519	2,026	2,108	1,774	1,950	1,824	1,674	1,597
Manitoba								
Fee	271	267	271	266	271	266	271	266
Crown	55	55	55	55	56	56	56	56
Freehold	23	23	23	23	23	23	23	23
	349	345	349	344	350	345	350	345
Newfoundland & Labrador								
Crown Onshore	39	10	39	10	87	43	87	43
Nunavut								
Crown	817	26	817	26	817	26	817	26
Northwest Territories								
Crown	1,036	438	1,036	438	1,569	806	1,566	806
	1,892	474	1,892	474	2,473	875	2,470	875
United States								
Federal Lands	5,794	2,733	5,460	2,476	3,167	1,664	3,077	1,572
Freehold	1,284	669	914	452	3,133	1,141	2,436	845
Fee	27	26	17	17	83	40	43	27
	7,105	3,428	6,391	2,945	6,383	2,845	5,556	2,444

Total North America (Onshore)	34,412	25,456	26,222	18,712	33,277	24,690	25,662	18,697

Landholdings, as at December 31

(thousands of acres)

	2002				2001			
	Total		Undeveloped		Total		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Beaufort Crown Offshore	126	4	126	4	227	5	227	5
Newfoundland & Labrador Crown Offshore	4,294	2,781	4,294	2,781	3,895	1,952	3,895	1,952
Nova Scotia Crown Offshore	4,908	3,066	4,908	3,066	4,405	2,461	4,405	2,461
United States Federal Lands Offshore	972	523	972	523	529	220	529	220
Total North America (Offshore)	10,300	6,374	10,300	6,374	9,056	4,638	9,056	4,638
Australia	19,159	6,750	19,159	6,750	18,674	6,598	18,674	6,598
Bahrain	97	48	97	48				
Brazil	1,932	1,488	1,932	1,488	1,932	1,488	1,932	1,488
Chad	108,536	54,268	108,536	54,268				
Colombia					1,170	1,170	1,170	1,170
Ecuador	1,093	796	985	766	1,094	797	985	726
Ghana	3,679	1,471	3,679	1,471	1,739	696	1,739	696
Greenland	985	985	985	985				
Libya					1,281	641	1,281	641
Qatar	2,758	1,103	2,758	1,103				
U.K. Offshore	1,346	418	1,317	414	1,648	443	1,619	439
Yemen	2,519	1,236	2,519	1,236	2,519	1,236	2,519	1,236
Other	346	17	346	17	346	17	346	17
Total International	142,450	68,580	142,313	68,546	30,403	13,086	30,265	13,011
Total	187,162	100,410	178,835	93,632	72,736	42,414	64,983	36,346

Notes:

(1) This table excludes approximately 3.8 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) Net acres are the sum of EnCana s fractional interest in gross acres.

Reserves

EnCana retained independent petroleum engineering consultants to evaluate and prepare reports on all of EnCana s oil and gas reserves as of December 31, 2002. In prior years, AEC s reserves were independently evaluated and PanCanadian s reserves were evaluated internally. Therefore, 2002 is the first year for which all of EnCana s reserves have been independently evaluated.

McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd. (GLJ) evaluated EnCana s Western Canada conventional reserves, Netherland, Sewell & Associates, Inc. evaluated EnCana s U.S. onshore reserves and Ryder Scott Company evaluated EnCana s international and offshore reserves. GLJ evaluated EnCana s share of Syncrude reserves.

EnCana has a Reserves Committee comprised entirely of independent directors which reviews EnCana s publicly-disclosed reserve estimates and approves the selection, qualifications and procedures of EnCana s independent engineering consultants.

Reserves Summary

The following table sets forth the combined estimates of EnCana s reserves as at December 31, 2002 from the independent engineers reports, on a constant price basis:

	Gross[1]					**Net[2]**				
	Proved Producing[3]	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**	**Proved Producing[3]**	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**
Natural Gas (billions of cubic feet)										
Canada	4,402	1,381	5,783	2,524	8,307	3,876	1,197	5,073	2,178	7,251
United States	1,691	1,479	3,170	918	4,088	1,352	1,221	2,573	754	3,327
United Kingdom	9	11	20	16	36	9	11	20	16	36
Total	6,102	2,871	8,973	3,458	12,431	5,237	2,429	7,666	2,948	10,614
Crude Oil (millions of barrels)										
Canada	297.0	292.1	589.1	538.1	1,127.2	266.8	248.2	515.0	453.6	968.6
United States	15.5	17.5	33.0	44.4	77.4	12.3	14.9	27.2	38.1	65.3
Ecuador	84.6	127.9	212.5	59.5	272.0	60.8	95.0	155.8	44.1	199.9
United Kingdom	7.1	88.3	95.4	88.5	183.9	7.1	88.3	95.4	88.5	183.9
Total	404.2	525.8	930.0	730.5	1,660.5	347.0	446.4	793.4	624.3	1,417.7
Natural Gas Liquids (millions of barrels)										
Canada	28.4	5.5	33.9	15.4	49.3	22.8	4.1	26.9	12.2	39.1
United States	9.8	7.1	16.9	7.2	24.1	8.0	5.7	13.7	5.8	19.5
United Kingdom	0.9	1.3	2.2	1.8	4.0	0.9	1.3	2.2	1.8	4.0
Total	39.1	13.9	53.0	24.4	77.4	31.7	11.1	42.8	19.8	62.6
Synthetic Oil (millions of										

barrels) (8)										
Canada (Syncrude)	298.2	135.8	434.0	278.5	712.5	253.9	113.8	367.7	228.4	596.1
Total	298.2	135.8	434.0	278.5	712.5	253.9	113.8	367.7	228.4	596.1
Total barrels of oil equivalent reserves (natural gas converted at 6:1)	1,758.6	1,154.1	2,912.7	1,609.8	4,522.5	1,505.3	976.3	2,481.6	1,364.1	3,845.7

See Notes on page 23.

Reserves Reconciliation

The following tables provide a reconciliation of the pro forma aggregate reserves of PanCanadian and AEC as at December 31, 2001 to EnCana s reserves as at December 31, 2002:

Reserves Reconciliation

Constant Price
Natural Gas *(billions of cubic feet)*

	Gross[1]					Net[2]				
	Proved Producing[3]	Proved Non-Producing[4]	Total Proved[5]	Probable[6][7]	Total	Proved Producing[3]	Proved Non-Producing[4]	Total Proved[5]	Probable[6][7]	Total
Canada										
PanCanadian end of year 2001	2,860	735	3,595	828	4,423	2,776	728	3,504	806	4,310
AEC end of year 2001	2,638	696	3,334	1,392	4,726	2,141	545	2,686	1,077	3,763
Pro forma balance end of year 2001	5,498	1,431	6,929	2,220	9,149	4,917	1,273	6,190	1,883	8,073
Revisions and improved recovery	(826)	(321)	(1,147)	42	(1,105)	(827)	(313)	(1,140)	71	(1,069)
Extensions and discoveries	622	314	936	338	1,274	548	274	822	291	1,113
Purchase of reserves in place	28	6	34	11	45	25	5	30	9	39
Sale of reserves in place	(99)	(49)	(148)	(87)	(235)	(87)	(42)	(129)	(76)	(205)
Sales	(821)		(821)		(821)	(700)		(700)		(700)
End of year 2002	4,402	1,381	5,783	2,524	8,307	3,876	1,197	5,073	2,178	7,251
United States										
PanCanadian end of year 2001	219	76	295	334	629	176	60	236	247	483
AEC end of year 2001	730	456	1,186	657	1,843	580	364	944	524	1,468
Pro forma balance end of year 2001	949	532	1,481	991	2,472	756	424	1,180	771	1,951
Revisions and improved recovery	470	424	894	(257)	637	365	366	731	(168)	563
Extensions and discoveries	67	344	411	156	567	54	284	338	129	467
Purchase of reserves in place	421	235	656	330	986	337	193	530	270	800
Sale of reserves in place	(34)	(56)	(90)	(302)	(392)	(27)	(46)	(73)	(248)	(321)
Sales	(182)		(182)		(182)	(133)		(133)		(133)
End of year 2002	1,691	1,479	3,170	918	4,088	1,352	1,221	2,573	754	3,327
United Kingdom										
PanCanadian end of year 2001	7		7		7	7		7		7
AEC end of year 2001										

Pro forma balance end of year 2001	7		7		7	7		7		7
Revisions and improved recovery	6	1	7	3	10	6	1	7	3	10
Extensions and discoveries		10	10	13	23		10	10	13	23
Purchase of reserves in place										
Sale of reserves in place										
Sales	(4)		(4)		(4)	(4)		(4)		(4)
End of year 2002	9	11	20	16	36	9	11	20	16	36
Australia										
PanCanadian end of year 2001										
AEC end of year 2001				36	36				36	36
Pro forma balance end of year 2001				36	36				36	36
Revisions and improved recovery				(36)	(36)				(36)	(36)
Extensions and discoveries										
Purchase of reserves in place										
Sale of reserves in place										
Sales										
End of year 2002										
Total										
PanCanadian end of year 2001	3,086	811	3,897	1,162	5,059	2,959	788	3,747	1,053	4,800
AEC end of year 2001	3,368	1,152	4,520	2,085	6,605	2,721	909	3,630	1,637	5,267
Pro forma balance end of year 2001	6,454	1,963	8,417	3,247	11,664	5,680	1,697	7,377	2,690	10,067
Revisions and improved recovery	(350)	104	(246)	(248)	(494)	(456)	54	(402)	(130)	(532)
Extensions and discoveries	689	668	1,357	507	1,864	602	568	1,170	433	1,603
Purchase of reserves in place	449	241	690	341	1,031	362	198	560	279	839
Sale of reserves in place	(133)	(105)	(238)	(389)	(627)	(114)	(88)	(202)	(324)	(526)
Sales	(1,007)		(1,007)		(1,007)	(837)		(837)		(837)
End of year 2002	6,102	2,871	8,973	3,458	12,431	5,237	2,429	7,666	2,948	10,614

See Notes on page 23.

Reserves Reconciliation

Constant Price
Crude Oil *(millions of barrels)*

	Gross[1]					Net[2]				
	Proved Producing[3]	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**	**Proved Producing[3]**	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**
Canada										
PanCanadian end of year 2001	238.7	49.8	288.5	99.1	387.6	216.9	42.0	258.9	86.4	345.3
AEC end of year 2001	125.8	110.3	236.1	142.5	378.6	116.3	106.5	222.8	127.0	349.8
Pro forma balance end of year 2001	364.5	160.1	524.6	241.6	766.2	333.2	148.5	481.7	213.4	695.1
Revisions and improved recovery	(51.0)	71.4	20.4	188.0	208.4	(53.1)	47.5	(5.6)	148.3	142.7
Extensions and discoveries	39.9	70.7	110.6	116.4	227.0	35.8	60.9	96.7	98.4	195.1
Purchase of reserves in place	5.5		5.5	1.7	7.2	4.9	(0.1)	4.8	1.4	6.2
Sale of reserves in place	(9.3)	(10.1)	(19.4)	(9.6)	(29.0)	(8.4)	(8.6)	(17.0)	(7.9)	(24.9)
Sales	(52.6)		(52.6)		(52.6)	(45.6)		(45.6)		(45.6)
End of year 2002	297.0	292.1	589.1	538.1	1,127.2	266.8	248.2	515.0	453.6	968.6
United States										
PanCanadian end of year 2001	4.5	0.8	5.3	29.3	34.6	4.2	0.7	4.9	29.0	33.9
AEC end of year 2001										
Pro forma balance end of year 2001	4.5	0.8	5.3	29.3	34.6	4.2	0.7	4.9	29.0	33.9
Revisions and improved recovery	8.0	12.6	20.6	(22.4)	(1.8)	5.7	10.8	16.5	(22.6)	(6.1)
Extensions and discoveries	0.8	2.6	3.4	29.7	33.1	0.6	2.2	2.8	25.4	28.2
Purchase of reserves in place	2.7	2.0	4.7	10.2	14.9	2.2	1.6	3.8	8.3	12.1
Sale of reserves in place	(0.4)	(0.5)	(0.9)	(2.4)	(3.3)	(0.3)	(0.4)	(0.7)	(2.0)	(2.7)
Sales	(0.1)		(0.1)		(0.1)	(0.1)		(0.1)		(0.1)
End of year 2002	15.5	17.5	33.0	44.4	77.4	12.3	14.9	27.2	38.1	65.3
Ecuador										
PanCanadian end of year 2001										
AEC end of year 2001	72.6	161.1	233.7	81.8	315.5	51.6	116.8	168.4	60.3	228.7
Pro forma balance end of year 2001	72.6	161.1	233.7	81.8	315.5	51.6	116.8	168.4	60.3	228.7
Revisions and improved recovery	27.6	(74.2)	(46.6)	(40.7)	(87.3)	19.4	(52.9)	(33.5)	(29.1)	(62.6)
	3.0	41.0	44.0	18.4	62.4	2.4	31.1	33.5	12.9	46.4

Extensions and discoveries										
Purchase of reserves in place										
Sale of reserves in place										
Sales	(18.6)		(18.6)		(18.6)	(12.6)		(12.6)		(12.6)
End of year 2002	84.6	127.9	212.5	59.5	272.0	60.8	95.0	155.8	44.1	199.9
United Kingdom										
PanCanadian end of year 2001	20.6		20.6	135.0	155.6	20.6		20.6	135.0	155.6
AEC end of year 2001										
Pro forma balance end of year 2001	20.6		20.6	135.0	155.6	20.6		20.6	135.0	155.6
Revisions and improved recovery	(9.7)	0.3	(9.4)	(46.5)	(55.9)	(9.7)	0.3	(9.4)	(46.5)	(55.9)
Extensions and discoveries		88.0	88.0		88.0		88.0	88.0		88.0
Purchase of reserves in place										
Sale of reserves in place										
Sales	(3.8)		(3.8)		(3.8)	(3.8)		(3.8)		(3.8)
End of year 2002	7.1	88.3	95.4	88.5	183.9	7.1	88.3	95.4	88.5	183.9
Total										
PanCanadian end of year 2001	263.8	50.6	314.4	263.4	577.8	241.7	42.7	284.4	250.4	534.8
AEC end of year 2001	198.4	271.4	469.8	224.3	694.1	167.9	223.3	391.2	187.3	578.5
Pro forma balance end of year 2001	462.2	322.0	784.2	487.7	1,271.9	409.6	266.0	675.6	437.7	1,113.3
Revisions and improved recovery	(25.1)	10.1	(15.0)	78.4	63.4	(37.7)	5.7	(32.0)	50.1	18.1
Extensions and discoveries	43.7	202.3	246.0	164.5	410.5	38.8	182.2	221.0	136.7	357.7
Purchase of reserves in place	8.2	2.0	10.2	11.9	22.1	7.1	1.5	8.6	9.7	18.3
Sale of reserves in place	(9.7)	(10.6)	(20.3)	(12.0)	(32.3)	(8.7)	(9.0)	(17.7)	(9.9)	(27.6)
Sales	(75.1)		(75.1)		(75.1)	(62.1)		(62.1)		(62.1)
End of year 2002	404.2	525.8	930.0	730.5	1,660.5	347.0	446.4	793.4	624.3	1,417.7

See Notes on page 23.

Reserves Reconciliation

Constant Price
Natural Gas Liquids *(millions of barrels)*

	Gross[1]					Net[2]				
	Proved Producing[3]	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**	**Proved Producing[3]**	**Proved Non-Producing[4]**	**Total Proved[5]**	**Probable[6][7]**	**Total**
Canada										
PanCanadian end of year 2001	23.1	4.7	27.8	5.6	33.4	23.0	4.7	27.7	5.0	32.7
AEC end of year 2001	11.3	4.0	15.3	8.4	23.7	8.0	2.9	10.9	6.0	16.9
Pro forma balance end of year 2001	34.4	8.7	43.1	14.0	57.1	31.0	7.6	38.6	11.0	49.6
Revisions and improved recovery	(3.4)	(4.2)	(7.6)	0.7	(6.9)	(5.7)	(4.2)	(9.9)	0.6	(9.3)
Extensions and discoveries	4.5	1.6	6.1	1.7	7.8	3.6	1.2	4.8	1.4	6.2
Purchase of reserves in place	0.1		0.1	0.1	0.2	0.1		0.1	0.1	0.2
Sale of reserves in place	(0.9)	(0.6)	(1.5)	(1.1)	(2.6)	(0.7)	(0.5)	(1.2)	(0.9)	(2.1)
Sales	(6.3)		(6.3)		(6.3)	(5.5)		(5.5)		(5.5)
End of year 2002	28.4	5.5	33.9	15.4	49.3	22.8	4.1	26.9	12.2	39.1
United States										
PanCanadian end of year 2001	10.7	8.1	18.8	23.7	42.5	9.1	5.6	14.7	17.3	32.0
AEC end of year 2001	5.2	3.1	8.3	4.3	12.6	4.1	2.4	6.5	3.4	9.9
Pro forma balance end of year 2001	15.9	11.2	27.1	28.0	55.1	13.2	8.0	21.2	20.7	41.9
Revisions and improved recovery	(9.0)	(6.7)	(15.7)	(26.3)	(42.0)	(7.5)	(4.4)	(11.9)	(19.3)	(31.2)
Extensions and discoveries	0.6	0.2	0.8		0.8	0.5	0.2	0.7		0.7
Purchase of reserves in place	5.2	2.4	7.6	5.5	13.1	4.2	1.9	6.1	4.4	10.5
Sale of reserves in place										
Sales	(2.9)		(2.9)		(2.9)	(2.4)		(2.4)		(2.4)
End of year 2002	9.8	7.1	16.9	7.2	24.1	8.0	5.7	13.7	5.8	19.5
United Kingdom										
PanCanadian end of year 2001	1.0		1.0		1.0	1.0		1.0		1.0
AEC end of year 2001										
Pro forma balance end of year 2001	1.0		1.0		1.0	1.0		1.0		1.0
Revisions and improved recovery	0.2	0.1	0.3	1.8	2.1	0.2	0.1	0.3	1.8	2.1
		1.2	1.2		1.2		1.2	1.2		1.2

Extensions and discoveries										
Purchase of reserves in place										
Sale of reserves in place										
Sales	(0.3)		(0.3)		(0.3)	(0.3)		(0.3)		(0.3)
End of year 2002	0.9	1.3	2.2	1.8	4.0	0.9	1.3	2.2	1.8	4.0
Australia										
PanCanadian end of year 2001										
AEC end of year 2001				0.2	0.2				0.2	0.2
Pro forma balance end of year 2001				0.2	0.2				0.2	0.2
Revisions and improved recovery				(0.2)	(0.2)				(0.2)	(0.2)
Extensions and discoveries										
Purchase of reserves in place										
Sale of reserves in place										
Sales										
End of year 2002										
Total										
PanCanadian end of year 2001	34.8	12.8	47.6	29.3	76.9	33.1	10.3	43.4	22.3	65.7
AEC end of year 2001	16.5	7.1	23.6	12.9	36.5	12.1	5.3	17.4	9.6	27.0
Pro forma balance end of year 2001	51.3	19.9	71.2	42.2	113.4	45.2	15.6	60.8	31.9	92.7
Revisions and improved recovery	(12.2)	(10.8)	(23.0)	(24.0)	(47.0)	(13.0)	(8.5)	(21.5)	(17.1)	(38.6)
Extensions and discoveries	5.1	3.0	8.1	1.7	9.8	4.1	2.6	6.7	1.4	8.1
Purchase of reserves in place	5.3	2.4	7.7	5.6	13.3	4.3	1.9	6.2	4.5	10.7
Sale of reserves in place	(0.9)	(0.6)	(1.5)	(1.1)	(2.6)	(0.7)	(0.5)	(1.2)	(0.9)	(2.1)
Sales	(9.5)		(9.5)		(9.5)	(8.2)		(8.2)		(8.2)
End of year 2002	39.1	13.9	53.0	24.4	77.4	31.7	11.1	42.8	19.8	62.6

See Notes on page 23.

Reserves Reconciliation

Constant Price
Synthetic Oil(8) *(millions of barrels)*

	Gross(1)					Net(2)				
	Proved Producing(3)	Proved Non-Producing(4)	Total Proved(5)	Probable(6)(7)	Total	Proved Producing(3)	Proved Non-Producing(4)	Total Proved(5)	Probable(6)(7)	Total
Canada (Syncrude)(8)										
PanCanadian end of year 2001										
AEC end of year 2001	310.8	121.3	432.1	278.1	710.2	280.0	104.6	384.6	235.2	619.8
Pro forma balance end of year 2001	310.8	121.3	432.1	278.1	710.2	280.0	104.6	384.6	235.2	619.8
Revisions and improved recovery	(1.1)	14.5	13.4	0.4	13.8	(14.7)	9.2	(5.5)	(6.8)	(12.3)
Extensions and discoveries										
Purchase of reserves in place										
Sale of reserves in place										
Sales	(11.5)		(11.5)		(11.5)	(11.4)		(11.4)		(11.4)
End of year 2002	298.2	135.8	434.0	278.5	712.5	253.9	113.8	367.7	228.4	596.1

Notes:

(1) Gross reserves are the remaining reserves of EnCana, before deduction of estimated royalties.

(2) Net reserves are the remaining reserves of EnCana, after deduction of estimated royalties.

(3) Proved Producing reserves are those proved reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of EnCana rather than the lack of markets or some other reasons.

(4) Proved Non-Producing reserves are those proved reserves that are not currently producing either due to a lack of facilities and/or markets.

(5) Total Proved reserves are those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(6) Probable reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(7) Canadian securities legislation and policies permit the disclosure of probable reserves, which may not be disclosed in documents filed with the SEC by U.S. companies. Probable reserves are generally believed to be less likely to be recovered than proved reserves. The reserve

estimates included in this AIF could be materially different from the quantities and values ultimately realized.

(8) Synthetic Oil is oil derived from the upgrading of crude bitumen and which is largely interchangeable with conventional crude oil as a refinery feedstock. The Corporation has agreed to sell certain of its Syncrude interests. See Item 3 General Development of the Business Onshore North America .

(9) The constant price evaluation assumes the continuance of laws, regulations, prices and operating costs in effect on December 31, 2002. In addition, operating and capital costs have not been increased on an inflationary basis.

History Daily Sales Volume and Per-Unit Results

The following tables summarize daily sales volume and per-unit results for EnCana and AEC on a quarterly basis for the periods 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 for PanCanadian and AEC. Accordingly, the amounts shown for the year for EnCana for 2002 exclude the results of AEC prior to April 5, 2002 and the amounts for EnCana for 2001 and the first quarter of 2002 represent solely the results of PanCanadian.

	EnCana Daily Sales Volume 2002				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
Produced Gas (*million cubic feet/day*)					
Canada	1,917	2,375	2,129	2,144	1,002
United States	427	654	550	428	72
United Kingdom	10	8	9	8	11
Total Produced Gas	2,354	3,037	2,688	2,580	1,085
Oil and Natural Gas Liquids (*barrels/day*)					
Onshore North America					
Conventional light and medium oil	65,263	62,369	65,345	66,807	66,575
Conventional heavy oil	66,498	86,019	80,797	76,233	22,081
Natural gas liquids Canada	16,066	19,121	16,225	16,796	12,042
Natural gas liquids United States	7,184	11,558	6,702	7,115	3,274
Total Onshore North America conventional	155,011	179,067	169,069	166,951	103,972
Syncrude	23,777	34,261	36,039	24,295	
Total Onshore North America	178,788	213,328	205,108	191,246	103,972
Offshore & International					
Ecuador	41,521	49,934	55,579	59,864	
United Kingdom	10,528	7,786	9,538	11,966	12,889
Total Offshore & International	52,049	57,720	65,117	71,830	12,889
Total Oil and Natural Gas Liquids	230,837	271,048	270,225	263,076	116,861

	EnCana Daily Sales Volume 2001				
	Year	Q4	Q3	Q2	Q1
SALES					
Produced Gas (*million cubic feet/day*)					
Canada	982	996	977	985	969
United States	62	72	62	63	52
United Kingdom	9	9	10	8	8
Total Produced Gas	1,053	1,077	1,049	1,056	1,029
Oil and Natural Gas Liquids (*barrels/day*)					
Onshore North America					
Conventional light and medium oil	68,010	67,276	69,600	67,881	67,263
Conventional heavy oil	21,972	22,459	22,333	18,529	24,589
Natural gas liquids Canada	10,652	11,057	10,173	10,620	10,758
Natural gas liquids United States	2,443	2,224	2,954	2,207	2,383
Total Onshore North America	103,077	103,016	105,060	99,237	104,993
Offshore & International					
United Kingdom	11,362	10,839	12,669	10,914	11,012
Total Offshore & International	11,362	10,839	12,669	10,914	11,012
Total Oil and Natural Gas Liquids	114,439	113,855	117,729	110,151	116,005

	AEC Daily Sales Volume					
	2002	2001				
	Q1	Year	Q4	Q3	Q2	Q1
SALES						
Produced Gas (*million cubic feet/day*)						
Canada	1,346	1,106	1,173	1,176	1,029	1,043
United States	293	217	259	219	212	178
Total Produced Gas	1,639	1,323	1,432	1,395	1,241	1,221
Oil and Natural Gas Liquids (*barrels/day*)						
Onshore North America						
Conventional light and medium oil	4,339	4,802	4,543	4,680	4,914	5,077
Conventional heavy oil	46,765	40,909	40,796	43,752	41,248	37,779
Natural gas liquids Canada	5,406	4,998	5,529	4,762	4,887	4,805

Natural gas liquids United States	3,153	2,291	2,855	2,536	2,201	1,556
Total Onshore North America conventional	59,663	53,000	53,723	55,730	53,250	49,217
Syncrude	31,548	30,687	32,347	28,938	29,162	32,319
Total Onshore North America	91,211	83,687	86,070	84,668	82,412	81,536
Offshore & International	38,774	51,899	51,055	51,472	53,498	51,582
Total Oil and Natural Gas Liquids	129,985	135,586	137,125	136,140	135,910	133,118

	EnCana Per-Unit Results 2002				
	Year	Q4	Q3	Q2	Q1
Produced Gas Canada (*$/thousand cubic feet*)[1]					
Price, net of transportation and selling[2]	4.18	5.09	3.53	4.11	3.56
Royalties	0.57	0.77	0.39	0.65	0.30
Operating costs	0.55	0.59	0.58	0.54	0.46
Netback including hedge	3.06	3.73	2.56	2.92	2.80
Hedge	0.07	(0.08)	0.29	(0.12)	0.32
Netback excluding hedge	2.99	3.81	2.27	3.04	2.48
Produced Gas United States (*C$/thousand cubic feet*)[1]					
Price, net of transportation and selling[2]	4.25	5.16	3.73	3.62	3.76
Royalties	1.16	1.42	0.99	0.98	1.10
Operating costs	0.34	0.28	0.34	0.38	0.77
Netback including hedge	2.75	3.46	2.40	2.26	1.89
Hedge	0.36	0.42	0.57	0.06	
Netback excluding hedge	2.39	3.04	1.83	2.20	1.89
Conventional Light and Medium Oil (*$/barrel*)					
Price, net of transportation and selling	32.42	35.10	35.12	33.76	25.78
Royalties	4.53	4.81	4.56	4.36	4.39
Operating costs	6.73	7.16	6.58	7.25	5.95
Netback including hedge	21.16	23.13	23.98	22.15	15.44
Hedge	(1.16)	(1.26)	(0.89)	(1.59)	(0.91)
Netback excluding hedge	22.32	24.39	24.87	23.74	16.35
Conventional Heavy Oil (*$/barrel*)					
Price, net of transportation and selling	25.91	24.63	28.55	26.09	20.51
Royalties	3.38	3.43	3.67	3.09	3.12
Operating costs	6.22	5.64	6.71	5.87	8.00
Netback including hedge	16.31	15.56	18.17	17.13	9.39
Hedge	(0.95)	(1.18)	(0.89)	(0.76)	(0.91)
Netback excluding hedge	17.26	16.74	19.06	17.89	10.30
Total Conventional Oil (*$/barrel*)					
Price, net of transportation and selling	29.14	29.04	31.49	29.67	24.47
Royalties	3.95	4.01	4.07	3.68	4.08
Operating costs	6.48	6.28	6.66	6.51	6.46
Netback including hedge	18.71	18.75	20.76	19.48	13.93
Hedge	(1.05)	(1.22)	(0.89)	(1.15)	(0.91)

Netback excluding hedge	19.76	19.97	21.65	20.63	14.84
Natural Gas Liquids (*$/barrel*)					
Price, net of transportation and selling	30.70	36.15	31.18	29.92	20.06
Royalties	4.49	5.95	4.62	4.69	1.00
Netback	26.21	30.20	26.56	25.23	19.06
Syncrude (*$/barrel*)					
Price, net of transportation and selling	41.83	42.29	42.54	40.09	
Gross overriding royalty and other revenue	0.14	0.11	0.17	0.16	
Royalties	0.43	0.43	0.43	0.42	
Operating costs	18.80	16.31	13.38	30.47	
Netback including hedge	22.74	25.66	28.90	9.36	
Hedge	(0.91)	(0.94)	(1.19)	(0.42)	
Netback excluding hedge	23.65	26.60	30.09	9.78	

	EnCana Per-Unit Results 2002				
	Year	Q4	Q3	Q2	Q1
Ecuador Oil (*C$/barrel*)					
Price, net of transportation and selling	33.43	35.38	33.59	31.63	
Royalties	11.82	12.29	12.51	10.76	
Operating costs	5.43	6.04	4.60	5.70	
Netback including hedge	16.18	17.05	16.48	15.17	
Hedge	(0.01)			(0.04)	
Netback excluding hedge	16.19	17.05	16.48	15.21	
United Kingdom Oil (*C$/barrel*)					
Price, net of transportation and selling	36.14	37.99	39.30	37.78	30.85
Operating costs	5.15	11.10	5.71	3.12	2.83
Netback including hedge	30.99	26.89	33.59	34.66	28.02
Hedge	(0.09)				(0.30)
Netback excluding hedge	31.08	26.89	33.59	34.66	28.32

Notes:

(1) Excludes the effect of $168 million increase to consolidated revenues relating to the mark-to-market value of the AEC fixed price forward natural gas contracts.

(2) Operating netbacks for the product include the margin impact of marketing activities related to the purchase and sale of third party volumes of the similar product.

	EnCana Per-Unit Results 2001				
	Year	Q4	Q3	Q2	Q1
Produced Gas Canada (*$/thousand cubic feet*)					
Price, net of transportation and selling[1]	6.53	4.30	5.68	7.15	9.10
Royalties	0.38	0.28	0.22	0.43	0.60
Operating costs	0.47	0.53	0.48	0.47	0.40
Netback including hedge	5.68	3.49	4.98	6.25	8.10
Hedge	0.58	1.05	2.10	0.41	(1.29)
Netback excluding hedge	5.10	2.44	2.88	5.84	9.39
Produced Gas United States (*C$/thousand cubic feet*)					
Price, net of transportation and selling[1]	3.85	2.83	3.81	3.01	6.39
Royalties	1.72	1.00	1.19	1.80	3.29
Operating costs	0.73	0.62	1.06	0.64	0.60
Netback including hedge	1.40	1.21	1.56	0.57	2.50
Hedge					
Netback excluding hedge	1.40	1.21	1.56	0.57	2.50
Conventional Light and Medium Oil (*$/barrel*)					
Price, net of transportation and selling	29.77	26.38	33.33	29.87	29.37
Royalties	4.20	3.67	4.18	5.51	3.42
Operating costs	6.56	5.85	6.51	7.23	6.66
Netback including hedge	19.01	16.86	22.64	17.13	19.29
Hedge	1.14	7.47	(0.36)	(0.80)	(1.77)
Netback excluding hedge	17.87	9.39	23.00	17.93	21.06
Conventional Heavy Oil (*$/barrel*)					
Price, net of transportation and selling	17.43	12.06	25.37	17.28	15.17
Royalties	2.28	1.79	3.16	2.25	1.94
Operating costs	9.31	9.78	7.84	11.45	8.63
Netback including hedge	5.84	0.49	14.37	3.58	4.60
Hedge					
Netback excluding hedge	5.84	0.49	14.37	3.58	4.60
Total Conventional Oil (*$/barrel*)					
Price, net of transportation and selling	26.76	22.80	31.40	27.17	25.57
Royalties	3.73	3.20	3.94	4.81	3.02
Operating costs	7.23	6.83	6.84	8.13	7.18
Netback including hedge	15.80	12.77	20.62	14.23	15.37
Hedge	0.86	5.60	(0.27)	(0.63)	(1.29)

Netback excluding hedge	14.94	7.17	20.89	14.86	16.66
Natural Gas Liquids (*$/barrel*)					
Price, net of transportation and selling	31.20	21.86	29.12	34.91	39.30
Royalties	1.22	0.42	1.51	1.81	1.17
Netback	29.98	21.44	27.61	33.10	38.13
United Kingdom Oil (C*$/barrel*)					
Price, net of transportation and selling	36.21	35.96	32.05	36.27	41.26
Operating costs	4.18	6.32	3.16	2.82	4.72
Netback including hedge	32.03	29.64	28.89	33.45	36.54
Hedge	0.76	7.25	(1.18)	(2.40)	0.08
Netback excluding hedge	31.27	22.39	30.07	35.85	36.46

Note:

(1) Operating netbacks for the product include the margin impact of marketing activities related to the purchase and sale of third party volumes of the similar product.

	AEC Per-Unit Results					
	2002	2001				
	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas Canada ***($/thousand cubic feet)***						
Price, net of transportation and selling	3.20	5.25	2.98	3.26	6.02	9.37
Royalties	0.65	1.18	0.60	0.73	1.44	2.11
Operating costs	0.55	0.51	0.54	0.51	0.51	0.47
Netback including hedge	2.00	3.56	1.84	2.02	4.07	6.79
Hedge						
Netback excluding hedge	2.00	3.56	1.84	2.02	4.07	6.79
Produced Gas United States ***(C$/thousand cubic feet)***						
Price, net of transportation and selling	3.35	5.51	3.48	3.93	6.72	9.04
Royalties	0.65	1.04	0.64	0.77	1.31	1.67
Production Taxes	0.26	0.50	0.32	0.35	0.60	0.82
Operating costs	0.29	0.29	0.29	0.23	0.27	0.35
Netback including hedge	2.15	3.68	2.23	2.58	4.54	6.20
Hedge(1)		0.21				0.73
Netback excluding hedge	2.15	3.47	2.23	2.58	4.54	5.47
Conventional Light and Medium Oil ***($/barrel)***						
Price, net of transportation and selling	31.09	36.21	33.28	36.21	37.40	37.69
Royalties	4.74	6.23	4.52	7.09	6.66	6.52
Operating costs	6.35	6.21	6.46	6.36	5.82	6.17
Netback including hedge	20.00	23.77	22.30	22.76	24.92	25.00
Hedge	0.73	2.51	10.04			
Netback excluding hedge	19.27	21.26	12.26	22.76	24.92	25.00
Conventional Heavy Oil ***($/barrel)***						
Price, net of transportation and selling	22.05	20.62	22.70	24.71	18.23	16.20
Royalties	1.90	2.40	2.01	3.14	2.06	2.33
Operating costs	4.75	4.78	4.52	4.90	4.93	4.76
Netback including hedge	15.40	13.44	16.17	16.67	11.24	9.11
Hedge	0.73	2.51	10.04			
Netback	14.67	10.93	6.13	16.67	11.24	9.11
Total Conventional Oil ***($/barrel)***						
Price, net of transportation and selling	22.81	22.23	23.60	25.83	20.26	18.75
Royalties	2.14	2.79	2.21	3.52	2.55	2.83
Operating costs	4.88	4.95	4.79	5.04	5.02	4.93
Netback including hedge	15.79	14.49	16.60	17.27	12.69	10.99

Hedge	0.73	2.51	10.04			
Netback excluding hedge	15.06	11.98	6.56	17.27	12.69	10.99
Natural Gas Liquids ***($/barrel)***						
Price, net of transportation and selling	27.49	34.92	24.41	34.97	40.30	42.96
Royalties	7.46	10.24	7.29	9.62	12.02	12.92
Netback	20.03	24.68	17.12	25.35	28.28	30.04
Syncrude ***($/barrel)***						
Price, net of transportation and selling	34.86	42.02	41.83	40.74	42.27	43.17
Gross overriding royalty and other revenue	0.13	0.64	0.13	0.19	2.15	0.18
Royalties	(0.23)	3.08	(0.60)	4.95	4.41	3.94
Operating costs	17.73	19.74	16.54	20.75	21.54	20.48
Netback including hedge	17.49	19.84	26.02	15.23	18.47	18.93
Hedge	0.80	2.67	10.05			
Netback excluding hedge	16.69	17.17	15.97	15.23	18.47	18.93
Ecuador Oil ***(C$/barrel)***						
Price, net of transportation and selling	22.07	26.24	23.62	28.43	28.12	24.71
Royalties	7.05	8.10	5.85	9.76	8.72	8.05
Operating costs	5.78	4.98	4.70	5.04	5.63	4.53
Netback including hedge	9.24	13.16	13.07	13.63	13.77	12.13
Hedge	0.07	1.09	4.40			
Netback excluding hedge	9.17	12.07	8.67	13.63	13.77	12.13

Note:

(1) Relates to contract volume of approximately 66 million cubic feet per day from November 1, 2000 to March 31, 2001.

History Acquisitions and Capital Expenditures

EnCana s growth in recent years has been achieved through a balance of internal growth and acquisitions. EnCana has a large inventory of high quality 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 tables summarize acquisition and capital expenditures related to EnCana s and AEC s upstream and midstream activities on a quarterly basis for the periods 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 for PanCanadian and AEC. Accordingly, the amounts shown for the year for EnCana for 2002 exclude the results of AEC prior to April 5, 2002 and the amounts for EnCana for 2001 and the first quarter of 2002 represent solely the results for PanCanadian.

EnCana

Acquisitions and Capital Expenditures
($ million)

	2002				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Acquisition of AEC	14,053.0			14,053.0	
Property Acquisitions	1,135.8	95.3	554.7	485.8	
Land	212.4	100.4	36.6	66.6	8.8
Exploration	1,061.5	391.2	232.4	254.1	183.8
Development	2,327.7	834.6	641.2	578.4	273.5
Other	116.0	35.6	27.2	41.8	11.4
Dispositions	(576.7)	(193.1)	(120.5)	(261.2)	(1.9)
Total Upstream	4,276.7	1,264.0	1,371.6	1,165.5	475.6
Corporate Acquisitions					
Pipelines and Processing	13.0	6.0	2.0	3.0	2.0
Gas Storage	62.7	45.0	4.6	13.1	
Power Assets	4.0	(2.0)	4.0	0.5	1.5
Marketing	7.1		4.3	2.8	
Equity Investment					
Dispositions	(42.0)	(42.0)			
Total Midstream	44.8	7.0	14.9	19.4	3.5
Total	18,374.5	1,271.0	1,386.5	15,237.9	479.1

EnCana

Acquisitions and Capital Expenditures
($ million)

	2001				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Corporate Acquisitions	72.0		72.0		
Property Acquisitions	93.4	4.8	81.4	7.3	(0.1)
Land	93.6	14.7	41.5	33.5	3.9
Exploration	622.4	263.2	174.6	96.9	87.7
Development	931.0	307.8	122.1	254.3	246.8
Other	49.6	10.5	7.4	19.0	12.7
Dispositions	(187.9)	(4.0)	(34.9)	(6.0)	(143.0)
Total Upstream	1,674.1	597.0	464.1	405.0	208.0
Corporate Acquisitions					
Pipelines and Processing					
Gas Storage	7.9	7.9			
Power Assets	143.2	32.3	37.5	47.8	25.6
Marketing	13.5	13.5			
Equity Investment					
Dispositions	(13.6)				(13.6)
Total Midstream	151.0	53.7	37.5	47.8	12.0
Total	1,825.1	650.7	501.6	452.8	220.0

AEC

Acquisitions and Capital Expenditures
($ million)

	2002	2001				
	Q1	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Corporate Acquisitions		296.5				296.5
Property Acquisitions	52.1	315.5	64.7	166.0	36.1	48.7
Land	55.2	217.9	37.8	30.1	90.8	59.2
Exploration	138.7	426.8	126.7	92.9	75.9	131.3
Development	551.6	1,894.0	415.0	416.0	418.9	644.1
Other	58.5	38.5	15.1	5.4	10.7	7.3
Dispositions	(35.7)	(145.5)	(8.2)	(37.5)	(75.3)	(24.5)
Total Upstream	820.4	3,043.7	651.1	672.9	557.1	1,162.6
Corporate Acquisitions		130.9				130.9
Pipelines and Processing	4.6	240.9	89.5	87.1	40.6	23.7
Gas Storage	2.7	89.8	8.3	8.7	2.3	70.5
Power Assets						
Marketing						

Equity Investment		26.5				26.5
Dispositions		(958.3)	(374.2)	(568.2)	(15.9)	
Total Midstream	7.3	(470.2)	(276.4)	(472.4)	27.0	251.6
Total	827.7	2,573.5	374.7	200.5	584.1	1,414.2

Future Commitments

The following table summarizes EnCana s future commitments to purchase, sell or transport natural gas and to purchase or transport crude oil at December 31, 2002:

Future Commitments

As at December 31, 2002

	Total Commitment	Price	Volume	Term of Commitment
	($ million)	($/thousand cubic feet)	(billion cubic feet)	
Gas				
Purchases	147.5	4.74	31.1	1 Year
Sales	1,243.9	4.93	252.5	11 Years
Transportation	2,580.5	0.21	12,032.3	14 Years

	Total Commitment	Price	Volume	Term of Commitment
	($ million)	($/cubic meter)	(million cubic meters)	
Crude Oil				
Purchases	86.4	302.40	0.3	1 Year
Transportation	2,411.5	16.53	145.9	12 Years

MIDSTREAM & MARKETING

Midstream

EnCana s midstream activities are primarily comprised of three business units: Gas Storage, Natural Gas Liquids and Power. In addition, EnCana continues to have equity interests in pipelines in South America. EnCana s 2003 capital investment in core programs in its midstream operations is anticipated to be approximately $446 million.

Gas Storage

Based upon overall storage capacity, EnCana is the largest independent (non-utility) gas storage operator in North America with facilities in Alberta, California and Oklahoma. EnCana also leases gas storage capacity from other storage operators located in the U.S. Gulf Coast and mid-continent regions. EnCana has storage capacity of approximately 145 billion cubic feet. The Corporation expects this capacity to increase upon completion of the expansion of its Wild Goose Gas Storage Facility in northern California and with the development of the new Countess Gas Storage Facility in southeastern Alberta.

EnCana provides a portion of its storage capacity to industry participants on a fee-for-service basis as well as offering short-term services such as parking, loaned gas, title exchange, and transportation exchange and interhub arrangements. The remaining capacity is used either to manage EnCana s produced gas sales, or as part of the gas storage optimization program (through the purchase and sale of third party gas).

AECO HUB

EnCana operates and markets its Alberta 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 recently announced 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. This expansion 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 System of TransCanada PipeLines Limited and the Alliance Pipeline system.

Countess Gas Storage Facility

In October 2002, EnCana announced plans to develop a new natural gas storage facility in southeastern Alberta that is expected to store up to 40 billion cubic feet of 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, will use two depleted underground reservoirs located about 85 kilometers east of Calgary. The first 10 billion cubic feet of new storage capacity is scheduled to be available by the third quarter of 2003. The full 40 billion cubic feet of storage capacity is expected to be available in April 2005.

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. Construction of this expansion commenced in 2002 and the initial portion of the incremental storage and withdrawal capacities are expected to be on-line by April 2004.

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.

Leased Storage Capacity

EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, has entered into contracts to lease storage capacity in Texas at the Katy Gas Storage Facility and in the U.S. mid-continent region at the facilities of the Natural Gas Pipeline Company of America, the ANR Storage Company and the ANR Pipeline Company. Total leased capacity is approximately 21 billion cubic feet, with remaining contract terms ranging from one to 14 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 at Empress, Alberta plus storage and fractionation assets in Saskatchewan, Eastern Canada and the United States, and gas gathering, processing, and fractionation facilities near Fort Lupton, Colorado.

At Empress, the rights to extract NGLs from natural gas transported through transmission pipelines are acquired from the shippers of the natural gas. The Empress NGLs extraction plant which the Corporation operates is undergoing an expansion that is expected to provide incremental ethane production of up to 15,000 barrels per day by the fall of 2003. As at December 31, 2002, 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 a 10.35 percent interest. The mixed stream is fractionated at Sarnia into marketable products: propane, butane, and pentanes plus. These are sold by EnCana s 75 percent owned affiliate

Kinetic Resources (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 a one-third interest in a pipeline which delivers ethane from NGLs extraction plants located at Waterton, Empress (four plants), Cochrane and Edmonton to ethylene plants at Joffre and Fort Saskatchewan and storage caverns at Fort Saskatchewan; a pipeline that delivers NGLs from Empress to storage facilities and the Enbridge pipeline at Kerrobert, Saskatchewan; a NGLs storage facility and depropanizer at Superior, Wisconsin; and, a propane and butane storage facility at Marysville, Michigan.

The Corporation owns and operates a system of field gas gathering, NGLs extraction and fractionation facilities near Fort Lupton, Colorado. The gathering facilities include field compression and over 650 miles of pipelines. The extraction plant has gas processing capacity of approximately 90 million cubic feet per day. These assets were acquired as part of the Montana Power acquisition.

Power

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 34 miles east of Calgary, is 100 percent owned and operated by EnCana. The Balzac Power Station, in which EnCana holds a 50 percent interest, is also located near Calgary and was brought into service in December 2001. EnCana also has a permit from the National Energy Board in Canada to export electricity to the U.S. for a period of 10 years. The Corporation also has a 25 percent interest in a cogeneration facility in Kingston, Ontario. EnCana s total power generation capacity is approximately 186 megawatts. In 2002, the Corporation generated 603,000 megawatt hours of EnCana owned electricity (474,000 megawatt hours in 2001).

Pipelines

OCP Pipeline

EnCana is part of a consortium that is building the 500-kilometer, 450,000 barrel per day OCP pipeline from the oil producing area of Ecuador to the Pacific Coast. In February 2001, an agreement was signed with the Government of Ecuador covering the commercial terms for the construction of the OCP pipeline. In July 2001, after receiving regulatory approval in June 2001, construction commenced on the OCP pipeline. Construction is targeted for completion by the end of the third quarter of 2003. 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. As of January 2003, the pipeline was approximately 85 percent complete. EnCana has an indirect 31.4 percent equity interest in the project.

Total costs for the OCP pipeline are estimated at approximately US$1.4 billion, of which US$900 million has been financed with project debt, and the balance to be provided by the project s sponsors. EnCana s share of the sponsor funding will be approximately US$160 million.

Trasandino Pipeline System

In February 2001, EnCana purchased a 36 percent equity interest in the Trasandino Pipeline system for approximately US$64 million. The Trasandino system carries crude oil from Argentina s Neuquen Basin to refineries in Chile. The pipeline is 263 miles in length and has a design capacity of approximately 113,000 barrels per day. Shipments on the Trasandino system in 2002 averaged approximately 112,000 barrels per day (approximately 110,900 barrels per day in 2001).

Marketing

Natural Gas Marketing

In 2002, approximately 86 percent of EnCana s produced natural gas sales were directly marketed by EnCana to local distribution companies, utilities, industrials and gas marketing companies. The remaining 14 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. Index pricing may be impacted by competing fuels in such markets and by supply and demand for natural gas.

As a means of managing volatility in natural gas prices, as of January 31, 2003, EnCana had entered into various hedging contracts relating to produced natural gas. Approximately 244 million cubic feet per day of Alberta natural gas

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has been sold forward under derivative contracts and 9 million cubic feet per day has been sold forward under physical contracts for 2003 at an average AECO equivalent of $5.89 per thousand cubic feet. Approximately 118 million cubic feet per day of Alberta natural gas has been sold forward under derivative contracts and 10 million cubic feet per day has been sold forward under physical contracts for 2003 at an average AECO equivalent of US$3.52 per thousand cubic feet. Approximately 287 million cubic feet of natural gas was sold forward under derivative contracts at an average NYMEX related price of US$4.10 per million British Thermal Unit for 2003. Approximately 181 million cubic feet per day of Alberta natural gas was sold forward under derivative contracts for the period January 2003 to December 2007 at an average NYMEX less AECO differential of US$0.49 per million British Thermal Unit. Approximately 167 million cubic feet per day of U.S. Rockies natural gas was sold forward under derivative contracts and 218 million cubic feet per day was sold forward under physical contracts for the period January 2003 to December 2007 at an average NYMEX less U.S. Rockies differential of US$0.48 per million British Thermal Unit. EnCana has also sold approximately 50 million cubic feet per day of U.S. Rockies natural gas forward for the period January 2003 to December 2007 at an average NYMEX less U.S. Rockies differential of US$0.38 per million British Thermal Unit in conjunction with a NYMEX costless collar with a price floor of US$2.46 per million British Thermal Unit and a ceiling price of US$4.90 per million British Thermal Unit.

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. In 2002, EnCana s sales of purchased natural gas amounted to approximately 962 million cubic feet per day (approximately 1,218 million cubic feet per day in 2001).

In 2002, EnCana sold approximately 58 percent of its natural gas at AECO based pricing (approximately 62 percent in 2001). As of December 31, 2002, for 2003 EnCana has arranged for the sale of approximately 23 percent of its natural gas at fixed prices, approximately 36 percent exposed to AECO index based prices and approximately 41 percent exposed to NYMEX based prices.

Crude Oil Marketing

EnCana sells and transports its western Canadian conventional crude oil to markets in Canada and the U.S. (116,634 barrels per day in 2002 and 105,646 barrels per day in 2001). Crude oil sales are normally made at a major pipeline hub, such as Edmonton, Hardisty or Cromer, in Alberta with EnCana arranging the intermediate transportation on the feeder pipeline systems. These sales can also be made on a delivered basis using trunk pipeline systems for sales to refinery destinations.

The Corporation sells conventional light sweet crude to a variety of customers primarily under spot and monthly evergreen contracts. Heavy oil is sold primarily under monthly evergreen or term contracts to a number of Canadian and U.S. based refiners. EnCana markets its equity share of Syncrude production (31,556 barrels per day in 2002) to a number of Canadian and U.S. based refiners.

EnCana provides marketing services to a number of organizations on a fee basis. In 2001, EnCana acted exclusively as agent for COS and marketed COS Syncrude volumes (24,555 barrels per day). This COS agency arrangement continued in January 2002 (50,533 barrels per day). From February 2002 to December 2002, this agreement required EnCana to purchase COS Syncrude volumes for resale (46,108 barrels per day). The COS marketing agreement, which includes a marketing fee, will revert back to a fee basis arrangement in February 2003 and terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government (48,133 barrels per day in 2002 and 36,225 barrels per day in 2001). This agency agreement was renewed in the second quarter of 2002 and ends in the second quarter of 2007 and also includes a marketing fee. Another marketing agreement is being reviewed in the first quarter of 2003 with the Petrovera Partnership. Under this agreement, EnCana marketed 24,618 barrels per day in 2002 (27,557 barrels per day in 2001), which corresponds to EnCana s share of the Petrovera Partnership s production. This agreement ends in the fourth quarter 2005.

In Ecuador, EnCana s crude oil volumes are sold FOB at the loading facility at Balao (near Esmeraldas), Ecuador. A total of 37,252 barrels per day was marketed in 2002.

Further to a letter of intent that was signed in October 2001, negotiations continue on a long-term sales agreement relating to 25,000 barrels per day with the Chilean national oil company. A related initiative contemplates EnCana acquiring up a 30 percent interest in the construction of a new coker facility in Concon, Chile. The coker investment is conditional upon certain matters that include finalizing the financial and commercial agreements and completing the aforementioned sales agreement, which are anticipated to occur during the second quarter of 2003.

In the U.K., EnCana s crude oil volumes are marketed by an indirect subsidiary of the Corporation. EnCana marketed 10,543 barrels per day in 2002 (10,759 barrels per day in 2001).

As a means of managing volatility in crude oil prices, as of January 31, 2003, EnCana had entered into various hedging contracts relating to crude oil. For 2003, EnCana has approximately 40,000 barrels per day in costless collars with a price floor averaging US$21.95 per barrel and a price cap of US$29.00 per barrel. Also for 2003, there are approximately 85,000 barrels per day in fixed price swaps with an average price of US$25.28 per barrel. For 2004, EnCana has approximately 62,500 barrels per day in costless collars with a price floor averaging US$20.00 per barrel and a price cap of US$25.69 per barrel. Also for 2004, there are approximately 62,500 barrels per day in fixed price swaps with an average price of US$23.13 per barrel.

NGLs Marketing

In 2002, Kinetic continued to market a portion of EnCana s Western Basin NGLs primarily to Eastern Canada and the U.S. Kinetic also markets NGLs on behalf of other parties.

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 an inspection and audit program, 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 site restoration costs as existing oil and natural gas properties are produced; however, EnCana does not anticipate making material extraordinary expenditures for compliance with environmental regulations in 2003. The amount of depreciation, depletion and amortization expense for EnCana s future site restoration for all oil and natural gas operations provided for in the Corporation s 2002 audited consolidated financial statements was approximately $119 million ($102 million for North American upstream operations and $17 million for international operations) and EnCana has accrued approximately $497 million ($440 million for North American operations and $57 million for international operations) for such future costs at December 31, 2002.

Given EnCana s current wells and facilities, the total anticipated future cost over the life of the reserves, less the total amount accrued at December 31, 2002, is estimated to be $909 million ($850 million for North American upstream operations and $59 million for international upstream operations).

Employees

At December 31, 2002, EnCana employed 3,646 people on a permanent basis as set forth in the following table:

	Number of Permanent Employees As at December 31, 2002
Upstream	
North America	2,208
International	981
Midstream & Marketing	457
Total	3,646

Foreign Operations

While 90 percent of EnCana s reserves and production are in North America, EnCana is exposed to risks and uncertainties as portions of EnCana s operations and related assets are located in countries outside North America, some of which may be considered politically and economically unstable. These operations and related assets 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.

ITEM 5: SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following sets forth selected financial information for EnCana and AEC 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 and 2000 represent solely the results of PanCanadian.

	EnCana(1) Year Ended December 31			AEC(5) Year Ended December 31	
	2002	2001	2000	2001	2000
	($ million, except per share amounts)				
Revenues, net of royalties and production taxes(3)	10,011	4,894	4,366	6,273	5,524
Cash flow from operations	3,821	2,306	2,303	2,023	2,235
Net earnings(2),(3)	1,224	1,287	1,021	824	922
Total assets(2),(3)	31,322	10,800	9,000	14,098	12,382
Long-term debt(3)	7,395	2,210	964	3,658	2,854
Project financing debt				584	573
Per Share Data(2)					
Cash flow from operations					
Per share basic	9.15	9.02	9.11	13.55	15.53
Per share diluted	8.99	8.81	8.95	12.57	14.89
Net earnings					
Per share basic	2.92	5.02	4.02	5.24	6.19
Per share diluted	2.87	4.90	3.95	4.98	5.97
Dividends(4)					
Dividend per common share	0.40	5.00	0.40	0.60	0.40

Notes:

(1) In July 2002, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from a subsidiary of Williams for approximately $550 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 for approximately $420 million. In October 2000, PanCanadian purchased the exploration production, midstream and marketing divisions of Montana Power for approximately $689 million. In the first quarter of 2000, PanCanadian completed the purchase of 13.5 percent and 20.2 percent interests in the Scott and Telford fields respectively in the U.K. central North Sea, for approximately $259 million.

(2) At January 1, 2002, the Corporation retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recorded in earnings as they arise. As required by the standard, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $28 million for the year-ended December 31, 2002 (2001 $17 million decrease; 2000 $18 million decrease). Also, the Corporation reviewed its accounting practices for operations outside of Canada and determined that such operations are self-sustaining. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the operations are deferred and included as a separate component of shareholders equity. This change in practice was adopted prospectively beginning April 5, 2002, and resulted in an increase in net earnings of $2 million for the year ended December 31, 2002.

(3) Following the Merger, the Corporation determined to discontinue the Houston-based merchant energy operation of its predecessor company, PanCanadian, which was included in the Midstream & Marketing segment. Accordingly, these operations have been 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. Accordingly, these operations have been accounted for as discontinued operations.

(4) EnCana s dividend policy is examined annually by the Board of Directors. As part of the CPL reorganization, the Corporation paid a Special Dividend of $1,180 million ($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 regular quarterly dividend.

(5) As reported in AEC s Annual Information Form dated February 20, 2002.

ITEM 6: MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

Management s Discussion and Analysis of Financial Condition for the year ended December 31, 2002, accompanying the 2002 audited consolidated financial statements, is incorporated by reference.

ITEM 7: MARKET FOR SECURITIES

All 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 7.00 percent 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.

ITEM 8: DIRECTORS AND OFFICERS

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

DIRECTORS

Name and Municipality of Residence	Director Since[10]	Principal Occupation
MICHAEL N. CHERNOFF[2,6] West Vancouver, British Columbia	1999	Corporate Director
PATRICK D. DANIEL[1,5] Calgary, Alberta	2001	President & Chief Executive Officer Enbridge Inc. *(Energy, transportation and services)*
IAN W. DELANEY[3,5] Toronto, Ontario	1999	Chairman of the Board Sherritt International Corporation *(Nickel/ cobalt mining, oil and natural gas production, electricity generation)*
WILLIAM R. FATT[1,2,7] Toronto, Ontario	1995	Chief Executive Officer Fairmont Hotels & Resorts Inc. *(Hotels)*
MICHAEL A. GRANDIN[3,5,6,8] Calgary, Alberta	1998	Chairman & Chief Executive Officer Fording Canadian Coal Trust *(Metallurgical coal)*
BARRY W. HARRISON[1,4] Calgary, Alberta	1996	Corporate Director and independent businessman
RICHARD F. HASKAYNE, O.C.[3,4] Calgary, Alberta	1992	Chairman of the Board TransCanada PipeLines Limited *(Pipelines and energy services)*
JOHN C. LAMACRAFT[1,3,6] Toronto, Ontario	1996	Chairman of the Board Aber Diamond Corporation *(Diamond marketing company)*
DALE A. LUCAS[1,5] Calgary, Alberta	1997	President D. A. Lucas Enterprises Inc. *(International energy project consulting)*
KEN F. MCCREADY[2,5,9]	1992	President

Calgary, Alberta		K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
GWYN MORGAN[2a,5a] Calgary, Alberta	1993	President & Chief Executive Officer EnCana Corporation
VALERIE A.A. NIELSEN[2,3] Calgary, Alberta	1990	Corporate Director

Name and Municipality of Residence	Director Since[10]	Principal Occupation
DAVID P. O BRIEN[1a,2a,3a,4,5a,6a] Calgary, Alberta	1990	Chairman EnCana Corporation
DENNIS A. SHARP[2,4] Calgary, Alberta	1998	Chairman & Chief Executive Officer UTS Energy Corporation *(Oil and natural gas company)*
T. DON STACY[1,4,6] Houston, Texas	1998	Corporate Director
JAMES M. STANFORD[3,6] Calgary, Alberta	2001	President Stanford Resource Management Inc. *(Investment management)*

Notes:

1 Audit Committee. ([1a] Ex officio member)

2 Corporate Responsibility, Environment, Health and Safety Committee. ([2a] Ex officio member)

3 Human Resources and Compensation Committee. ([3a] Ex officio member)

4 Nominating and Corporate Governance Committee.

5 Pension Committee. ([5a] Ex officio member)

6 Reserves Committee. ([6a] Ex officio member)

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

8 Mr. Grandin was a director of Pegasus Gold Inc. (Pegasus) when it filed a voluntary petition for relief under Chapter 11 of the *Bankruptcy Code* (United States) in January 1998. The United States Bankruptcy Court, District of Nevada, confirmed the joint liquidating plan of reorganization filed by Pegasus in December 1998 and Pegasus successor company emerged from bankruptcy in 1999.

9 Mr. McCready was a director of Colonia Corporation, which company was placed into receivership in October 2000. The company came out of receivership in October 2001.

10 Denotes the year each individual became a director of either AEC or PanCanadian.

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

At the date of this AIF, there are 16 directors of the Corporation. The By-Laws of the Corporation provide that all of the directors shall retire from office at the next Annual Meeting of Shareholders and, 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	President & Chief Executive Officer

Calgary, Alberta	
RANDALL K. ERESMAN Calgary, Alberta	Senior Executive Vice-President & Chief Operating Officer
DAVID J. BOONE Calgary, Alberta	Executive Vice-President
BRIAN C. FERGUSON Calgary, Alberta	Executive Vice-President, Corporate Development
GERALD J. MACEY Calgary, Alberta	Executive Vice-President
R. WILLIAM OLIVER Calgary, Alberta	Executive Vice-President
GERARD J. PROTTI Calgary, Alberta	Executive Vice-President, Corporate Relations
DRUDE RIMELL Calgary, Alberta	Executive Vice-President, Corporate Services
JOHN D. WATSON 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 is a geologist and engineer by profession. He was President of Pacalta Resources Ltd. from 1988 to 1996 and Chairman of the Board 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 and was Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from January 1994 to December 1997.

Mr. Grandin became Chairman and Chief Executive Officer of Fording Canadian Coal Trust in February 2003 and has been a director since October 2001. He was President of PanCanadian Energy Corporation from October 2001 to April 2002, Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from December 1997 to October 2001, and Vice Chairman and Director of Midland Walwyn Capital Inc. from October 1996 to November 1997.

Mr. Harrison was President of Black Sea Energy Ltd. from February 1998 to August 1998 and President of Quest Oil & Gas Inc. from October 1996 to April 1997.

Mr. Haskayne was Chairman of Fording Inc. from October 2001 until February 2003 and he was the Chairman of NOVA Corporation from April 1992 until its merger with TransCanada PipeLines Limited in July 1998.

Mr. Lamacraft served as Chairman and a director of Jascan Resources Inc. from July 1989 to October 2000. He served as President and Chief Executive Officer of Conwest Exploration Corporation Limited from 1979, and as a director from 1974 until January 1996 when Conwest Exploration Corporation was acquired by AEC.

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.

Mr. Sharp was Chairman and Chief Executive Officer of CS Resources Limited from January 1984 to July 1997, and Chairman and Chief Executive Officer of UTS Energy Corporation from February 1998 to present.

Mr. Stacy was Chairman and President of Amoco Canada Petroleum Ltd. from 1986 to 1993, and then Chairman and President of Amoco Eurasia Petroleum Corporation Ltd. from 1993 to 1997.

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

Mr. Boone was Business Development Manager for West Africa at Exxon Upstream Development Company from October 1998 to February 2000, and prior thereto held various positions within Imperial Oil Limited.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 19, 2003, directly or indirectly, or exercised control or direction over an aggregate number of 1,166,541 common shares representing 0.24 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an additional 2,965,660 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 Canada Business Corporations Act, 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.

ITEM 9: 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, 2002.

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 AIF, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the AIF,

(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 AIF 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

ENCANA CORPORATION

2002

Management s Discussion

and Analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing EnCana Corporation (EnCana or the Company) shareholders and potential investors with information regarding the Company, certain statements throughout this Management s Discussion and Analysis (MD&A) constitute 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 , forecast , target or similar words suggesting future outcomes or statements regarding a Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company s operating costs; oil and gas prices for 2003; increases in the Company s crude oil, natural gas liquids and natural gas production in 2003 and beyond; the Company s reserves levels; the impact of the Company s risk management program; the Company s capital investment levels and the capital investment level of the Company s divisions; the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Company; the development of new natural gas storage facilities and increases in the Company s gas storage capacity; the execution of share purchases under the Company s Normal Course Issuer Bid program; the volatility of world energy prices including crude oil prices; the anticipated timing for the assessment of goodwill impairment and the charging of any impairment to income; the anticipated timing and results of discontinuing the Houston-based merchant energy operation; the proposed use of proceeds from the disposition of the Express and Cold Lake pipeline interests; the timing for completing the OCP pipeline, the expected capacity of the OCP pipeline and the Company s expected final investment in the OCP pipeline; the cost of future dismantlement and site restoration; anticipated geographic regions targeted for production growth; the anticipated effect of changes in commodity prices and the U.S./Canadian dollar exchange rate; the impact of legal claims on the financial position and results of operations of the Company; the Company s oilsands strategy and the expected closing date of the sale of a portion of the Company s interest in the Syncrude project; the results of inquiries by U.S. governmental agencies; the Company s ability to extend its debt on an ongoing basis; and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Company 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 MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company s North American and foreign oil and gas and midstream operations, risks inherent in the Company s marketing operations, imprecision of reserves and resource potential estimates, the Company s ability to replace and expand oil and gas reserves, the Company s ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company s ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company 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 and development drilling, imprecision in estimates of future production capacity, the Company s 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, political and economic conditions in the countries in which the Company operates including Ecuador, the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company operates and international terrorist threats, and such other risks and uncertainties described from time to time in the Company s reports and filings with the Canadian securities authorities and the U.S. Securities and Exchange Commission. Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to reserves or resources are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and 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. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which are made as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

This Management s Discussion and Analysis (MD&A) for EnCana Corporation (EnCana or the Company) should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes. The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). A reconciliation to United States GAAP is included in Note 23 to the Consolidated Financial Statements.

OVERVIEW

On January 27, 2002, PanCanadian Energy Corporation (PanCanadian) and Alberta Energy Company Ltd. (AEC) announced that their respective Boards of Directors had unanimously agreed to merge the two companies.

On April 5, 2002, PanCanadian and AEC completed this merger, creating EnCana Corporation. The companies satisfied all closing conditions, including receipt of approvals from shareholders of PanCanadian, shareholders and optionholders of AEC and the Court of Queen s Bench of Alberta. Under the terms of the merger, AEC shareholders received 1.472 EnCana common shares for each AEC common share owned. Further information with respect to the merger transaction is contained in Note 3 to the audited consolidated financial statements (Consolidated Financial Statements).

The Consolidated Financial Statements include the results of AEC from April 5, 2002, the closing date of the merger. As such, the amounts reported for the year ended December 31, 2002 reflect twelve months of PanCanadian results combined with the nine months of post merger AEC results. The comparative figures are based solely on the 2001 and 2000 results of PanCanadian.

EnCana reports the results of its operations under two main business segments: Upstream and Midstream & Marketing. The Company s Upstream business segment consists of the Onshore North America, Offshore & International Operations and the Offshore & New Ventures Exploration divisions. Onshore North America includes EnCana s North America onshore exploration for, and production of, natural gas, natural gas liquids and crude oil. The Offshore & International Operations division develops the reserves associated with offshore and international discoveries. The division currently has production in Ecuador and the U.K. central North Sea and major developments in the East Coast of Canada, Gulf of Mexico and the U.K. central North Sea. The Offshore & New Ventures Exploration division includes the Company s exploration activity in the Canadian East Coast, the North American frontier region, the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia and Latin America. The Company s Midstream & Marketing business segment includes gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company s own production.

CONSOLIDATED FINANCIAL RESULTS

EnCana s cash flow from continuing operations of $3,779 million, or $8.89 per common share-diluted (per share), marked an historic year of record level cash flow, compared with $2,259 million, or $8.63 per share, in 2001 and $2,278 million, or $8.86 per share, in 2000. The higher 2002 cash flow was the result of increased revenues, due primarily to growth in sales volumes and lower cash tax expense, which were offset by higher costs for transportation and selling, operating, purchased product, administration and interest.

2002 net earnings from continuing operations were $1,225 million, or $2.87 per share, compared with $1,254 million, or $4.77 per share, in 2001 and $1,000 million, or $3.87 per share, in 2000. Earnings in 2002 were affected by significantly weaker Western Canada and U.S. Rockies regional (regional) natural gas prices. The effect of the lower 2002 regional gas prices was partially offset by an increase in sales volumes resulting from the merger and the Company s expansion of its Onshore North America operations.

As discussed in Note 2 to the Consolidated Financial Statements, the Company is required to translate long-term debt 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 contained in self-sustaining foreign operations, in the foreign currency translation account included in Shareholders Equity in the Consolidated Balance Sheet. In order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt on the Company s results, the following table has been prepared:

($ millions)	2002	2001	2000
Net earnings, as reported	**$1,224**	$1,287	$1,021
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	**27**	(44)	(29)
Earnings, excluding foreign exchange on translation of U.S. dollar debt	**$1,197**	$1,331	$1,050
($ per common share diluted)			
Net earnings per common share diluted, as reported	**$ 2.87**	$ 4.90	$ 3.95
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	**0.06**	(0.17)	(0.11)
Earnings, excluding foreign exchange on translation of U.S. dollar debt per common share diluted	**$ 2.81**	$ 5.07	$ 4.06

* As this is an unrealized gain (loss) there is no impact on cash flow.

Earnings, excluding foreign exchange on the translation of U.S. dollar debt, and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this discussion and analysis in order to provide shareholders and potential investors with additional information regarding the Company s finances and results of operations.

Consolidated Financial Summary ($ millions, except per share amounts)	2002	2001	2000
Revenues, net of royalties and production taxes	**$10,011**	$4,894	$4,366
Net earnings from continuing operations	**1,225**	1,254	1,000
per common share-diluted	**2.87**	4.77	3.87
Net earnings	**1,224**	1,287	1,021
per common share-diluted	**2.87**	4.90	3.95
Cash flow from continuing operations	**3,779**	2,259	2,278
per common share-diluted	**8.89**	8.63	8.86
Cash flow	**3,821**	2,306	2,303
per common share-diluted	**8.99**	8.81	8.95

Quarterly contributions were as follows:

2002 Quarterly Information ($ millions, except per share amounts)	Q4	Q3	Q2	Q1*
Revenues, net of royalties and production taxes	$3,392	$2,882	$2,676	$1,061
Net earnings from continuing operations	416	184	494	131
per common share-diluted	0.86	0.38	1.05	0.51
Net earnings	429	204	458	133
per common share-diluted	0.88	0.42	0.97	0.51
Cash flow from continuing operations	1,449	1,027	916	387
per common share-diluted	2.99	2.13	1.95	1.48
Cash flow	1,472	1,022	938	389
per common share-diluted	3.03	2.12	2.00	1.49

* Q1 2002 results exclude the results of AEC.

ACQUISITIONS AND DIVESTITURES

Acquisitions

On May 31, 2002, the Company expanded its production, reserves, land holdings, and gathering system assets in the U.S. Rocky Mountain region with the purchase of assets by one of its U.S. subsidiaries for approximately $420 million. This acquisition complements the Company s existing Piceance Basin gas production at Mamm Creek and the surrounding area near Rifle, Colorado.

On August 1, 2002, the Company announced that one of its U.S. subsidiaries had further strengthened its position in the U.S. Rocky Mountain region through the purchase of producing and non-producing assets in the Jonah field, in southwest Wyoming, for approximately $550 million. The acquisition included developed and undeveloped reserves and increased EnCana s interest in the Jonah field production from approximately 50 percent to approximately 75 percent.

On January 31, 2003, the Company expanded its production and landholdings in Ecuador with the purchase of assets for approximately US$137 million, including working capital and subject to normal post-closing adjustments and expenses. This acquisition included interests in developed and undeveloped reserves in three blocks adjacent to Block 15, where the Company has a non-operated working interest.

Divestitures

In December 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $93 million with a gain on disposal of $51 million.

On February 3, 2003, the Company announced that it had reached an agreement to sell a 10 percent interest in the Syncrude project for approximately $1,070 million. The Company also granted the purchaser an option to purchase, on similar terms prior to the end of 2003, its remaining 3.75 percent share and an overriding royalty. If exercised, it is anticipated that the option would generate additional proceeds of approximately $417 million. With the sale of its Syncrude interest, the Company intends to focus its oilsands strategy on developing its high quality resources, recovered through steam-assisted gravity drainage (SAGD), on 100 percent owned and operated lands at Foster Creek and Christina Lake. The sale of EnCana s interest in Syncrude is subject to regulatory approvals and the completion of other closing conditions by the parties. The transaction is expected to close on or about February 28, 2003.

Discontinued Operations

Merchant Energy

On April 24, 2002, the Company adopted formal plans to exit from its Houston-based merchant energy operation, which was previously included in the Midstream & Marketing segment. The wind-down of this operation has been substantially completed. At December 31, 2002, an after-tax loss of $49 million has been recorded, which includes the costs associated with completing the wind-down of the Houston-based merchant energy operation. Upon review of additional information related to 2001 sales and purchases of natural gas by this U.S. operation, the Company determined that certain revenues and expenses should have been reflected in the financial statements in 2001 on a net basis as described in Note 5 to the Consolidated Financial Statements and as previously presented in the Company s unaudited interim consolidated financial statements in 2002. Certain of these 2001 natural gas sale and purchase transactions may be characterized as so-called round-trip transactions. The Company has received requests for information from several U.S. governmental agencies regarding these round-trip transactions. In addition, in connection with its investigation of Reliant Resources, Inc. and Reliant Energy, Inc., the U.S. Securities and Exchange Commission has issued a subpoena to the Company to produce all documents concerning round-trip transactions with those corporations. The Company has also received a subpoena from the U.S. Commodity Futures Trading Commission requiring the Company to produce documents and other information in connection with that agency s investigation relating to, among other things, inaccurate reporting of natural gas and power trading information by employees of a number of energy trading firms, including former employees of the Company s Houston-based merchant energy operation, to energy industry publications that compile and report index prices. The Company is cooperating fully in responding to all of these requests. While no assurance can be provided, based on information currently available to the Company, the Company believes that none of these inquiries by U.S. governmental agencies is likely to result in a material adverse effect upon the Company.

Midstream Pipelines

On July 9, 2002, the Company announced plans to dispose of its indirect 100 percent interest in the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System. On January 2, 2003, the Company announced that it had closed the sale of its interest in the Cold Lake Pipeline System for approximately $425 million, subject to post-closing adjustments. On January 9, 2003, the Company announced that it had closed the sale of its indirect 100 percent interest in the Express Pipeline System. The proceeds of this sale were approximately $1,175 million, including the assumption of approximately $599 million in debt, and are subject to post-closing adjustments. These two sales were part of EnCana s strategic realignment to focus on its highest growth, highest return core assets. It is anticipated that the proceeds will be used for general corporate purposes, including debt reduction, prior to being re-deployed into other strategic initiatives.

The merchant energy and midstream-pipeline operations described above have both been accounted for as discontinued operations as described in Note 5 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

(average for the year unless otherwise noted)	**2002**	**2001**	**2000**
AECO Price *($ per thousand cubic feet)*	**$ 4.07**	$ 6.30	$ 5.02
NYMEX Price *(US$ per million British thermal units)*	**3.22**	4.27	3.89
WTI *(US$ per barrel)*	**26.15**	25.95	30.26
WTI/Bow River Differential *(US$ per barrel)*	**5.93**	9.87	7.12
WTI/Oriente Differential (Ecuador) *(US$ per barrel)*	**4.16**	7.02	5.96
U.S./Canadian Dollar Exchange Rate *(US$)*	**0.637**	0.646	0.673

Natural gas prices in 2002 showed significant decline from strong 2001 average prices. The average AECO index price for 2002 was $4.07 per thousand cubic feet, down 35 percent from an average price of $6.30 per thousand cubic feet in 2001 and down 19 percent from $5.02 per thousand cubic feet in 2000. Although natural gas prices showed improvement in late 2002, for most of the year prices were negatively affected by high levels of natural gas in storage resulting from decreased demand. In 2002, the AECO index price continued to be strong relative to NYMEX prices. In 2002, the NYMEX to AECO basis differential increased to US$0.66 per million British thermal unit from US$0.29 per million British thermal unit in 2001. This was mainly caused by high levels of gas in storage and the decontracting of firm service forcing additional Alberta supply to flow on higher cost interruptible transport leaving the western basin.

World crude oil prices improved somewhat in 2002 compared with 2001 prices. The benchmark West Texas Intermediate (WTI) crude oil price averaged US$26.15 per barrel in 2002, compared with US$25.95 per barrel in 2001 and US$30.26 per barrel in 2000. Oil prices at the beginning of 2002 were low, with the WTI crude oil price averaging US$21.63 per barrel in the first quarter, but continued to climb throughout the year ending with an average price of US$28.23 per barrel in the fourth quarter. Oil prices gained strength during the year due in part to maintenance of production quotas by OPEC, uncertainty surrounding tensions in the Middle East and disruptions in the supply of oil from Venezuela.

In 2002, the differential between heavy and light crude oil prices benefited from improvements in the supply/demand balance for heavy oil. The WTI/Bow River differential averaged US$5.93 per barrel, compared with US$9.87 per barrel in 2001 and US$7.12 per barrel in 2000.

The average WTI/Oriente differential in 2002 was US$4.16 per barrel compared with US$7.02 per barrel and US$5.96 per barrel in 2001 and 2000, respectively. Oriente crude differentials narrowed in 2002 due to restricted heavy crude availability and a related decrease in the light/heavy product differential in the U.S. Gulf Coast. Restricted heavy crude availability arose from lower Iraq crude volumes, sporadic hurricanes on the U.S. Gulf Coast and, towards the end of the year, the sudden withdrawal of Venezuelan supply.

The U.S./Canadian dollar exchange rate experienced a fluctuating trend in 2002 reflecting economic and political uncertainties throughout the year. The Canadian dollar averaged US$0.637 in 2002, down from US$0.646 in 2001 and US$0.673 in 2000. At year-end the U.S./Canadian dollar exchange rate was US$0.633, compared with year-end rates of US$0.628 and US$0.667 in 2001 and 2000, respectively.

RESULTS OF OPERATIONS

Upstream Onshore North America and Offshore &International

Financial Results ($ millions)	**2002**				**2001**			
	Produced Gas & NGLs	**Conven- tional Crude Oil**	**Syncrude**	**Total**	**Produced Gas & NGLs**	**Conven- tional Crude Oil**	**Syncrude**	**Total**
Revenues								
Gross revenue	**$4,342**	**$2,142**	**$ 369**	**$6,853**	$2,680	$1,060	$	$3,740
Royalties and production taxes	**615**	**370**	**4**	**989**	180	123		303
Revenues, net of royalties and production taxes	**3,727**	**1,772**	**365**	**5,864**	2,500	937		3,437
Expenses								
Transportation and selling	**336**	**98**	**4**	**438**	121	35		156
Operating	**471**	**452**	**164**	**1,087**	192	254		446
Depreciation, depletion and amortization				**2,036**				799
Upstream income	**$2,920**	**$1,222**	**$ 197**	**$2,303**	$2,187	$ 648	$	$2,036

[Additional columns below]

[Continued from above table, first column(s) repeated]

Financial Results ($ millions)	**2000**			
	Produced Gas & NGLs	**Conven- tional Crude Oil**	**Syncrude**	**Total**
Revenues				
Gross revenue	$1,886	$1,340	$	$3,226
Royalties and production taxes	114	145		259
Revenues, net of royalties and production taxes	1,772	1,195		2,967
Expenses				
Transportation and selling	98	34		132
Operating	133	235		368
Depreciation, depletion and amortization				725
Upstream income	$1,541	$ 926	$	$1,742

Sales Volumes	2002	2001	2000
Produced Gas *(million cubic feet per day)*	**2,354**	1,053	949
Crude Oil *(barrels per day)*	**183,015**	100,803	109,355
NGLs *(barrels per day)*	**24,045**	13,636	12,665
Syncrude *(barrels per day)*	**23,777**		
Total *(barrel of oil equivalent per day)**	**623,170**	289,939	280,187

* Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

Revenues Variances ($ millions)	2002 compared to 2001				2001 compared to 2000		
	Price	Volume	Merger* Volume	Total	Price	Volume	Total
Produced gas and NGLs	$(579)	$487	$1,754	$1,662	$ 586	$ 208	$ 794
Conventional crude oil	137	80	865	1,082	(166)	(114)	(280)
Syncrude			369	369			
Total gross revenue	$(442)	$567	$2,988	$3,113	$ 420	$ 94	$ 514

* Represents estimate of revenue resulting from the addition of volumes related to existing AEC properties as at the date of the merger.

Consolidated Upstream Results

The Company reports its segmented financial results showing revenues prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry. Upstream gross revenue for the year rose 83 percent, or $3,113 million, to $6,853 million compared with 2001 and was $3,627 million higher than 2000 gross revenue. Included in 2002 gross revenue is $168 million relating to the fair value of AEC s forward gas sales contracts recorded as part of the business combination. This amount has been excluded for the purposes of discussing realized prices.

Excluding the impact of hedging, royalties and production taxes were 15 percent of revenues in 2002 compared with nine percent and eight percent in 2001 and 2000, respectively. The increased rate reflects the addition of AEC s production base, which is predominantly in areas subject to crown royalties, thereby decreasing the Company s relative proportion of production attributable to fee land where only mineral taxes are payable.

2002 transportation and selling costs were $438 million compared with $156 million in 2001 and $132 million in 2000. Higher sales volumes year over year were the primary factor contributing to the increase in these costs. For the purpose of the revenue discussions below, these costs have been netted against revenues in calculating the per unit realized prices for each commodity.

Upstream operating expenses, excluding Syncrude operations, totalled $923 million in the year, an increase of $477million over 2001. Additional production resulting from the merger with AEC was the primary factor contributing to the increase in costs. On a per unit basis, conventional operating expenses, excluding cost recoveries, were $4.06 per barrel of oil equivalent in 2002 compared with $4.21 per barrel of oil equivalent in 2001. The improvement in unit operating expenses primarily reflects the impact of lower costs associated with conventional crude oil production.

2001 upstream operating expenses of $446 million were $78 million higher than 2000 operating expenses of $368 million. The higher 2001 costs reflected higher downhole, maintenance, electricity and fuel costs.

Depreciation, depletion and amortization (DD&A) expense was $2,036 million for the year compared with $799 million in 2001 and $725 million in 2000. On a barrel of oil equivalent basis, DD&A charges were up 19 percent from 2001 to $8.95 per barrel. At $7.55 per barrel in 2001, DD&A charges were six percent higher than 2000 unit costs of $7.09 per barrel. The higher costs in 2002 primarily reflected the added charges associated with the addition of the AEC assets, which were recorded at their fair value as part of the allocation of the purchase price as outlined in Note 3 to the Consolidated Financial Statements.

Produced Gas and NGLs

Per-Unit Results Produced Gas and NGLs

	Produced Gas Canada			Produced Gas U.S.			NGLs		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
	($ per thousand cubic feet)			($ per thousand cubic feet)			($ per barrel)		
Price, net of transportation and selling	**$4.18**	$6.53	$ 4.76	**$4.25**	$3.85	$5.43	**$30.70**	$31.20	$33.31
Royalties and production taxes	**0.57**	0.38	0.29	**1.16**	1.72	2.34	**4.49**	1.22	1.77
Operating expenses	**0.55**	0.47	0.36	**0.34**	0.73	0.51			
Netback including hedge	**3.06**	5.68	4.11	**2.75**	1.40	2.58	**26.21**	29.98	31.54
Hedge	**0.07**	0.58	(0.13)	**0.36**					
Netback excluding hedge	**$2.99**	$5.10	$ 4.24	**$2.39**	$1.40	$2.58	**$26.21**	$29.98	$31.54

In 2002, sales of produced gas and natural gas liquids (NGLs) contributed $4,342 million to revenues, an increase of $1,662 million, or 62 percent, over 2001. The increase in 2002 gross revenue was largely attributable to increased sales volumes resulting from the merger with AEC in combination with the Company s expansion in the U.S. Rocky Mountain region, and drilling successes such as those at Jonah, Mamm Creek,Greater Sierra and Ferrier.

Produced gas sales volumes increased 1,301 million cubic feet per day over 2001, averaging 2,354 million cubic feet per day for the year. NGL sales also improved, to 24,045 barrels per day compared with sales volumes of 13,636 barrels per day in 2001. The impact of the Company s growth in natural gas sales volumes was partly offset by weaker regional natural gas prices. Realized natural gas sales prices in Canada averaged $4.18 per thousand cubic feet in 2002, a decrease of 36 percent from an average of $6.53 per thousand cubic feet in 2001. In contrast, the realized price for natural gas in the U.S. increased by approximately 10 percent over last year to $4.25 per thousand cubic feet.

Gross revenue from the sales of produced gas and NGLs was $2,680 million in 2001, an improvement over revenue of $1,886 million in 2000. Stronger 2001 Canadian market prices, the increase in production stemming from the acquisition of the Montana Power Assets in late 2000 and a successful drilling program contributed to the growth in 2001 revenue.

2002 gross natural gas revenue was $103 million higher as the result of a net gain from currency and commodity hedging activities. This compared to a gain of $208 million in 2001 and a loss of $43 million in 2000.

In 2002, produced gas operating expenses, net of operating recoveries, were $0.55 per thousand cubic feet for Canadian production and $0.34 per thousand cubic feet for U.S. production. This compared with $0.47 per thousand cubic feet for Canadian production and $0.73 per thousand cubic feet for U.S. production in 2001. Higher operating costs for British Columbia production, plant turnarounds and increased processing fees related to non-operated production were the primary factors contributing to the increase in costs for Canadian production. In 2002, unit operating costs related to U.S. production benefited from the addition of lower operating cost properties at Jonah and Mamm Creek acquired as part of the merger with AEC.

Unit operating expenses in 2001 were higher than 2000 unit costs for both Canadian and U.S. production. Factors underlying the rise in unit costs were increased downhole, maintenance, lease and electricity costs. The increased maintenance expense in 2001 partially reflected a compressor maintenance program in the first half of 2001 that was designed to improve service factors for natural gas facilities.

Conventional Crude Oil

Per-Unit Results Conventional Oil

	Onshore North America			Ecuador			United Kingdom		
($ per barrel)	2002	2001	2000	2002	2001	2000	2002	2001	2000
Price, net of transportation and selling	**$ 29.14**	$ 26.76	$ 32.95	**$ 33.43**	$	$	**$ 36.14**	$ 36.21	$ 28.47
Royalties and production taxes	**3.95**	3.73	4.05	**11.82**					
Operating expenses	**6.48**	7.23	5.94	**5.43**			**5.15**	4.18	5.29
Netback including hedge	**18.71**	15.80	22.96	**16.18**			**30.99**	32.03	23.18
Hedge	**(1.05)**	0.86	(1.50)	**(0.01)**			**(0.09)**	0.76	(10.69)
Netback excluding hedge	**$ 19.76**	$ 14.94	$ 24.46	**$ 16.19**	$	$	**$ 31.08**	$ 31.27	$ 33.87

In 2002, gross revenue from the sale of conventional crude oil was $2,142 million, an increase of $1,082 million, or 102 percent, over 2001. The improvement in gross revenue was primarily attributable to the volumes added from the merger of the Company with AEC combined with strengthened world oil prices and narrower North American heavy crude oil differentials.

Onshore North America conventional crude oil sales volumes averaged 131,761 barrels per day in 2002 compared with 89,982 barrels per day in 2001. The increase in sales volumes was the result of the inclusion of merger related volumes, continued development at Suffield, commencement of commercial production at Christina Lake and the ramping up of production at Foster Creek. The Company s 2002 realized price from Onshore North America crude was $29.14 per barrel, an improvement over an average price of $26.76 per barrel in 2001.

Unit operating costs for Onshore North America conventional crude oil were $6.48 per barrel, an improvement over costs of $7.23 per barrel in 2001. The improvement in operating expenses for the year was the result of lower per unit costs related to the added AEC production and lower electricity costs.

In 2001, unit operating costs increased to $7.23 per barrel compared with costs of $5.94 per barrel in 2000. The increase in crude oil operating expenses reflected higher downhole, maintenance, electricity and fuel costs.

Conventional oil sales from Offshore & International averaged 51,254 barrels per day, which compared with 10,821 barrels per day in 2001. The increase in sales volumes reflects the addition of 41,521 barrels per day of Ecuador oil volumes, which helped to offset a reduction in U.K. sales volumes. Realized crude oil prices on the Company s Offshore & International sales averaged $33.43 per barrel for Ecuador oil and $36.14 per barrel for U.K. oil. Comparatively, 2001 U.K. realized crude oil prices averaged $36.21 per barrel.

Offshore & International conventional crude oil unit operating costs were $5.43 per barrel for Ecuador oil and $5.15 per barrel for U.K. production in 2002. Costs related to U.K. crude oil production increased over 2001 costs of $4.18 per barrel due primarily to higher work-over, maintenance and insurance costs.

2001 gross revenue from sales of conventional crude oil declined 21 percent from 2000, to $1,060 million. Softer 2001 crude oil prices and a widening of the heavy crude oil differential contributed to the decline. In addition to weaker prices, 2001 conventional crude oil volume levels were lower as a result of general declines experienced in maturing crude oil pools and the Company s sale of non-core properties, such as the heavy crude oil operations at Pelican Lake in February 2001.

Conventional crude oil gross revenue in 2002 was reduced by a loss of approximately $51 million from commodity and currency hedging, which compared to a $31 million gain in 2001 and a loss of $100 million in 2000.

Syncrude

As a result of the merger, EnCana added Syncrude oil production to its Onshore North America upstream operating results. Syncrude sales added $369 million to upstream revenues in 2002 with sales volumes averaging 23,777 barrels per day. 2002 sales volumes were impacted by lower volume levels in the second quarter due to a longer than anticipated period for the coker turnaround. Volumes returned to expected levels of 36,039 barrels per day and 34,261 barrels per day in the third and fourth quarters, respectively. In 2002, Syncrude gross revenue was reduced by approximately $8 million resulting from a loss related to commodity price hedging.

Syncrude operating costs were $164 million in 2002, or $18.80 on a per unit basis. Operating expenses were impacted by high second quarter costs of $30.47 per barrel as a result of the coker turnaround.

As previously discussed, the Company has reached an agreement to sell a 10 percent interest in the Syncrude project and has granted the purchaser an option to purchase the remaining 3.75 percent interest and overriding royalty prior to the end of 2003. The transaction is expected to close on or about February 28, 2003. Further details regarding this sale are included in Note 22 to the Consolidated Financial Statements.

Midstream & Marketing

Financial Results* ($ millions)	Midstream			Marketing			Total		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Revenues	**$760**	$260	$311	**$3,373**	$1,202	$1,090	**$4,133**	$1,462	$1,401
Expenses									
Transportation and selling				**136**	16	16	**136**	16	16
Operating	**331**	228	229	**20**	19	23	**351**	247	252
Purchased product	**265**			**3,183**	1,144	1,019	**3,448**	1,144	1,019
Depreciation, depletion and amortization							**62**	20	17
	$164	$ 32	$ 82	**$ 34**	$ 23	$ 32	**$ 136**	$ 35	$ 97

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

In 2002, revenues from continuing midstream operations were $760 million compared with $260 million in 2001 and $311 million in 2000. The increase in 2002 was largely the result of the addition of the AEC midstream assets, which primarily include gas storage facilities and natural gas processing, to the Company s existing midstream segment. In addition, the NGLs processing business benefited from lower than forecast AECO gas prices lowering the cost of natural gas feedstock, which improved processing margins. Gas storage benefited from the late year volatility in gas prices and the optimization opportunities captured as a result. In 2001, revenues declined from 2000 levels due mainly to planned reductions in production of extracted NGLs.

Marketing Financial Results*

On a product basis ($ millions)	Gas			Crude Oil & NGLs			Total		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Revenues	**$1,456**	$595	$319	**$1,917**	$607	$771	**$3,373**	$1,202	$1,090
Expenses									
Transportation and selling	**58**	1	2	**78**	15	14	**136**	16	16
Operating							**20**	19	23
Purchased product	**1,349**	567	306	**1,834**	577	713	**3,183**	1,144	1,019
	$ 49	$ 27	$ 11	**$ 5**	$ 15	$ 44	**$ 34**	$ 23	$ 32

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

Gross revenue from the Company s marketing activities totalled $3,373 million in 2002, an increase over gross revenue of $1,202 million and $1,090 million in 2001 and 2000, respectively. The increase in 2002 largely reflected the addition of volumes related to the merger with AEC. In addition, a marketing arrangement with a third party also contributed to the increase in revenues from crude oil and NGLs. In 2002, this agreement required EnCana to purchase third party Syncrude volumes, approximately 46,108 barrels per day, for resale from February to December. During 2001 and January 2002, this marketing arrangement was on an agency basis, which did not require the Company to take physical title of these volumes. This agreement continues in 2003 but reverts back to an agency agreement from February 2003 forward.

Midstream & Marketing depreciation and amortization expenses were $62 million for the year compared with $20 million in 2001 and $17 million in 2000. The growth in the segment asset base resulting from the addition of AEC s midstream assets was the primary factor contributing to the increase in depreciation and amortization expenses.

Corporate

Administrative expenses for the year totalled $187 million. In comparison, these expenses were $83 million in 2001 and $68 million in 2000. The higher expenses in 2002 included increases in compensation costs, office facilities charges and information technology costs. The increase in these costs was primarily attributable to the increased size of the Company. On a per-unit basis, administrative costs were $0.82 per barrel of oil equivalent in 2002 compared with $0.78 per barrel of oil equivalent in 2001 and $0.66 per barrel of oil equivalent in 2000.

Net interest expense was $419 million, up from $45 million in 2001 and $69 million in 2000. The rise in net interest expense resulted primarily from the additional interest expense associated with debt acquired as a result of the merger, an increase resulting from higher debt levels associated with the U.S. dollar notes issued in the fourth quarter of 2001 and lower 2002 cash levels.

Foreign exchange resulted in a gain of $20 million, which compared with a loss of $20 million in 2001 and a $37 million loss in 2000. The majority of the foreign exchange impact results from the translation of U.S. dollar denominated debt where exchange gains and losses are recorded in earnings in the period they arise.

In conjunction with the merger, in the second quarter the Company reviewed its accounting practices for operations outside of Canada and determined that such operations were self-sustaining. Previously such operations had been considered to be integrated and as such were accounted for using the temporal method of translation. This change in classification resulted in a change to the current rate method of translation, which is used for self-sustaining operations and is described in Note 2 of the Consolidated Financial Statements. This change was adopted prospectively as of April 5, 2002 and resulted in an increase in net earnings of $2 million for the year ended December 31, 2002.

The provision for income tax was $618 million in 2002, $631 million in 2001 and $633 million in 2000. The decrease included the impact of a $47 million reduction in future income taxes resulting from a reduction in the Alberta corporate tax rate in 2002. The effective tax rate for 2002 was 33 percent. This compares to an effective tax rate of 34 percent in 2001 and 39 percent in 2000. The provision for current income tax decreased significantly in 2002, resulting in a recovery of $49 million compared with an expense of $497 million in 2001 and $163 million in 2000. The decrease reflects lower taxable income in 2002, which results in part from the merger with AEC and the subsequent resulting business reorganization of the Company s business units at the end of 2002 and early 2003, and the amalgamation with AEC on January 1, 2003. The current income tax decrease was offset by an equivalent increase in future income tax. The future income tax provision in 2002 was $667 million compared to $134 million in 2001 and $470 million in 2000.

On December 12, 2002, the Company announced that it intended to consolidate its corporate structure through a vertical short-form amalgamation with its wholly owned subsidiary AEC. The amalgamation was completed effective January 1, 2003 and did not require any EnCana or AEC public securityholder vote. Upon completion of the amalgamation, EnCana became the successor issuer in respect of AEC s previously issued debt securities and is responsible for all of AEC s contractual obligations.

LIQUIDITY AND CAPITAL RESOURCES

The Company believes that its existing credit facilities and present and expected capital resources, including the proceeds from the sales of its interests in the Express and Cold Lake Pipeline Systems and the sale of a 10 percent interest in Syncrude, will support its capital investment programs and future growth prospects, in addition to enabling the Company to meet all other current and expected financial requirements.

EnCana s cash flow from continuing operations of $3,779 million in 2002 compared with $2,259 million in 2001 and $2,278 million in 2000. The increased cash flow from continuing operations was primarily the result of higher revenues resulting from the Company s growth in sales volumes during the year and a lower cash tax expense.

At December 31, 2002, the Company had working capital of $410 million compared with $33 million at the end of 2001. The increase in working capital was primarily due to the current nature of the Company s discontinued assets at the end of the year and a reduction of $642 million in current income taxes payable compared with 2001. These were partially offset by the addition of $438 million in short-term debt and an increase in accounts payable resulting primarily from an expanded capital program in 2002.

EnCana s net debt at year-end, including preferred securities, increased to $7,568 million from $2,303 million at the end of 2001. This increase was primarily a result of the debt acquired in the merger. Net debt to capitalization, including all preferred securities as debt, was 36 percent, down from 37 percent at December 31, 2001.

At December 31, 2002, the Company had $2,886 million in goodwill recorded on its Consolidated Balance Sheet as a result of the merger with AEC. The amount of goodwill recorded represents the excess of the purchase price over the fair value of net assets acquired in the business combination. Details regarding the accounting for the business combination, including the allocation of the purchase price to assets and liabilities, are described in Note 3 to the Consolidated Financial Statements. The Company assesses goodwill for impairment at least on an annual basis, at which time any identified impairment would be charged to income. At December 31, 2002, there was no impairment related to goodwill.

At December 31, 2002, the Company had $457 million in preferred securities of a subsidiary recorded as a liability on its balance sheet. These preferred securities are unsecured junior subordinated debentures and were recorded as a liability of the Company following the merger with AEC. The Company recognized $20 million, net of tax for distributions on the preferred securities of the subsidiary in 2002. On January 1, 2003, these preferred securities became the direct obligation of EnCana as a result of the amalgamation of the Company with AEC and accordingly will be recorded under the shareholders equity section of the Consolidated Balance Sheet in future periods. Details regarding these preferred securities of subsidiary are described in Note 15 to the Consolidated Financial Statements.

On October 2, 2002, the Company issued $300 million of unsecured five-year debentures at a coupon rate of 5.30%. Proceeds from the offering were used to repay amounts outstanding under revolving credit and term loan borrowings.

On October 16, 2002 EnCana received approval from the Toronto Stock Exchange (TSX) to make a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. Purchases under the program must terminate on October 21, 2003 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the TSX. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies. The price to be paid will be the market price at the time of acquisition. As at December 31, 2002, the Company had not yet made any purchases under this program.

In December 2002, the Company completed the early redemption of its subsidiary s US$113 million 6.78% and US$85 million 7.34% unsecured private notes for total consideration, including accrued interest, of approximately US$226 million. The Company also completed the early redemption of its subsidiary s $430 million principal amount, Capital Securities for total consideration, including accrued interest, of approximately $495 million. These early retirements were completed in order to simplify the Company s financial structure and take advantage of lower interest rates. An after-tax charge of approximately $30 million was recorded in relation to these transactions.

In December 2002, the Company completed the refinancing of its general corporate bank credit facilities. Under this refinancing, five separate corporate facilities were consolidated into a single syndicated corporate bank credit facility totalling $4 billion to be used for general corporate purposes.

Capital Expenditures

The Company s consolidated net capital expenditures were $4,281 million in 2002 compared with $1,824 million in 2001 and $2,221 million in 2000. The Company s net investing for 2002 was funded by cash flow of $3,821 million and long-term debt.

Included in net capital expenditures for 2002 was $566 million related to proceeds on disposals of capital assets, compared with proceeds of $47 million in 2001 and $193 million in 2000. These disposals related primarily to property rationalization consistent with the Company s continued focus on maximizing profitability by selling non-core assets. Also included in 2002 net capital expenditures was $93 million related to proceeds on the sale of the Company s investment in EnCana Suffield Gas Pipeline Inc. This compared with $84 million in net corporate dispositions in 2001 and $948 million in corporate acquisitions in 2000. In 2001, net corporate dispositions included proceeds from the sale of an oil and gas property and the acquisition of Causeway, a junior oil and gas producer. Corporate acquisitions in 2000 reflected the Company s purchase of Montana Power and its interest in the Scott and Telford properties in the U.K.

The following table provides a summary of the Company s capital spending, excluding dispositions, on a divisional basis.

Capital Expenditures ($ millions)	**2002**	**2001**	**2000**
Upstream			
Onshore North America	**$3,662**	$1,356	$1,071
Offshore & International	**1,126**	407	266
Total Upstream	**4,788**	1,763	1,337
Midstream & Marketing	**87**	165	90
Corporate	**65**	27	39
Total	**$4,940**	$1,955	$1,466

Upstream Capital Expenditures

Onshore North America

In 2002, capital expenditures in the Onshore North America division were $3,662 million compared with $1,356 million in 2001 and $1,071 million in 2000. The majority of the division s 2002 capital expenditures were directed towards exploration and development of natural gas properties in the U.S. Rockies, the Greater Sierra area of northeastern British Columbia, southeastern Alberta and the Alberta Foothills, combined with heavy oil development at Suffield and Pelican Lake, commercial development of the SAGD projects at Foster Creek and Christina Lake and continued expansion at Syncrude. Capital spending in the year included approximately $420 million related to the purchase of Colorado natural gas properties and approximately $550 million related to the acquisition of producing and non-producing properties in southwestern Wyoming. In 2001 and 2000, the majority of capital spending was related to natural gas exploration and development.

Offshore & International

Capital expenditures were $1,126 million in 2002 compared with $407 million in 2001 and $266 million in 2000. The majority of 2002 capital spending was directed towards development of the producing properties in Ecuador, as well as the major exploration and development projects in the Gulf of Mexico, East Coast of Canada and the U.K. central North Sea. The Company was unsuccessful in finding commercial quantities of hydrocarbons in the Kingdom of Bahrain and consequently $28 million was written off as an expense in 2002. In 2001 and 2000, capital spending in the division was focused primarily on exploration and development in the U.K. central North Sea and East Coast of Canada.

Reserves

In addition to its own internal engineering, EnCana retained independent petroleum engineering consultants to evaluate and prepare reports on 100 percent of its oil and gas reserves as of December 31, 2002. The Company has a Reserve Committee comprised entirely of independent directors which reviews its publicly-disclosed reserve estimates and approves the selection, qualification and procedures of the independent engineering consultants.

During 2002, the Company added approximately 1,900 million barrels of oil equivalent, net of sales, sales of reserves in place and revisions, to its proved reserves through the merger with AEC, the acquisition of selected properties and drill bit successes. EnCana s proved reserves as at December 31, 2002, on a constant price basis, before royalties, totalled 2,913 million barrels of oil equivalent. The 2,913 million barrels of oil equivalent was comprised of 8,973 billion cubic feet of natural gas, 983 million barrels of conventional oil and NGLs and 434 million barrels of Syncrude. The following table provides a summary of the proved reserves by country:

Proved Reserves by Country As at December 31, 2002	**Canada**	**U.S.**	**Ecuador**	**U.K.**	**Total**
Natural Gas *(billions of cubic feet)*	5,783	3,170		20	8,973
Conventional Oil and NGLs *(millions of barrels)*	623	50	212	98	983
Syncrude *(millions of barrels)*	434				434
Total barrels of oil equivalent* *(millions of barrels)*	2,022	578	212	101	2,913

* Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

Midstream & Marketing Capital Expenditures

On October 17, 2002, EnCana announced plans to develop a new natural gas storage facility in southeastern Alberta that is anticipated to store up to 40 billion cubic feet of gas. On completion of the development, the Countess gas storage facility is expected to increase the Company s Western Canada gas storage capacity by approximately 40 percent to more than 135 billion cubic feet. At December 31, 2002, approximately $12 million had been invested. The Company expects that the total completion cost related to this project will be approximately $140 million.

Capital expenditures of $87 million were down from $165 million in 2001 and $90 million in 2000. The 2002 expenditures related primarily to ongoing improvements to midstream facilities, the construction of the Countess storage facility, and expansion of the Wild Goose storage facility. Capital expenditures in 2001 and 2000 were principally due to the construction of two new power generation plants in Alberta.

The construction of the 450,000 barrel per day OCP pipeline in Ecuador is continuing on target for final completion in the third quarter of 2003. It is expected that restricted transportation service, sufficient to meet initial shipper requirements, will be available by the middle of 2003. At December 31, 2002, $27 million had been invested related to the Company s 31.4% equity interest in the pipeline project. The Company estimates that its final investment will be approximately US$160 million.

Corporate Capital Expenditures

Corporate capital expenditures were $65 million in 2002, compared with $27 million in 2001 and $39 million in 2000. In 2002, these expenditures related primarily to spending on business information systems, furniture and office equipment and leasehold improvements. Expenditures in 2001 and 2000 related primarily to spending on business information systems.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has operating leases in place on a variety of moveable field equipment, natural gas storage equipment and aircraft, which require periodic lease payments, recorded as operating costs, and provide for a minimum stipulated return value. If the leases are not renewed and the market value of the equipment is less than the return value, the Company could be required to make whole any value deficiency at the end of the lease. The minimum stipulated return values amount to $144 million in 2005, $115 million in 2006 and $46 million in 2007 and beyond. At the inception of the leases the value of the equipment under lease was $370 million. The acquisitions of the equipment and aircraft were financed by variable interest entities that were sponsored by various financial institutions. These variable interest entities are not consolidated into the Company s financial statements. The Company has accounted for these arrangements as operating leases in accordance with Canadian GAAP.

The Financial Accounting Standards Board (FASB) in the United States has issued FASB Interpretation No.46 (FIN 46) Consolidation of Variable Interest Entities effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that the primary beneficiary consolidate certain variable interest entities. These operating leases will be consolidated under the new standard as written. Further details regarding these operating leases are included in Note 21 to the Consolidated Financial Statements.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. The following table summarizes the Company s contractual obligations at December 31, 2002:

	Maturity				
Contractual Obligations* ($ millions)	**Less than 1 year**	**1 3 years**	**4 5 years**	**In Excess of 5 years**	**Total**
Long Term Debt	$ 212	$ 496	$ 615	$4,147	$ 5,470
Preferred Securities of Subsidiary				457	457
Preferred Securities				126	126
Operating Leases	71	277	215	283	846
Transportation Agreements	461	889	782	2,859	4,991
Capital Commitments	791	379	44	61	1,275
Product Purchase Agreements	32	2	47	307	388
Other Long Term Obligations	8	55	33	45	141
Total Contractual Obligations	$1,575	$2,098	$1,736	$8,285	$13,694

* This table outlines the principal amounts of the noted obligations.

In addition to the long-term debt payments outlined above, at December 31, 2002, the Company had $2,047 million outstanding related to commercial paper borrowings and term loan borrowings that are supported by revolving credit facilities. The Company intends and has the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company s long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the other contractual obligations outlined above is included in Note 21 to the Consolidated Financial Statements.

As of December 31, 2002, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 68 million cubic feet per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 224 billion cubic feet at a weighted average price of $4.79 per thousand cubic feet. At December 31, 2002, these transactions had an unrealized loss of $220 million.

ACCOUNTING POLICIES

Critical Accounting Policies

Management is often required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining EnCana s financial results.

Full Cost Accounting

EnCana follows the Canadian Institute of Chartered Accountants guideline on full cost accounting in the oil and gas industry to account for conventional oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proven reserves (see reserves discussion below), before royalties. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization (DD&A). A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss.

Oil and Gas Reserves

Commencing in 2002, EnCana s proved oil and gas reserves are 100 percent evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

Asset Impairment

Under full cost accounting, a ceiling test is performed, on a quarterly basis, to ensure that unamortized capitalized costs in each cost centre do not exceed the sum of estimated undiscounted, unescalated future net revenues from proved reserves, plus unimpaired unproved property costs, less future development costs, related production, dismantlement and site restoration, interest, administrative costs and applicable taxes. The ceiling test calculation utilizes and holds constant the sales prices and costs in effect at the end of the period. As a result, the calculation of future net revenues from estimated proved reserves are not necessarily reflective of the Company s estimate of future prices or costs and are therefore not necessarily indicative of the true fair value of the reserves. As discussed above, an impairment loss is recognized when the estimated undiscounted future cash flows are less than the net book value of the related capitalized costs.

Future Dismantlement and Site Restoration

The Company provides for estimated future dismantlement and site restoration costs of natural gas and crude oil assets using the unit-of-production method. The estimation of this future liability is inherently difficult and is based on estimates of future costs to abandon and restore a well site. Factors that influence these cost estimates include such things as the number of wells drilled, well depth and area specific environmental legislation. These estimates are revisited on a yearly basis and impact the DD&A rates used by the Company. An upward revision in these future costs could result in a higher DD&A expense being charged to earnings.

Stock-Based Compensation

The Company has a stock-based compensation plan that allows employees and directors to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options are issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Generally accepted accounting principles provide the Company with the choice to record a compensation expense in the financial statements for granted share options. EnCana has chosen not to record compensation expense for share options granted to employees and directors. If the fair-value method had been used, approximately $80 million in compensation expense would have been charged against the Company s net earnings. Further details regarding the Company s stock-based compensation plan are included in Note 17 of the Consolidated Financial Statements.

Changes in Accounting Principles

Foreign Currency Translation

At January 1, 2002, the Company retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recorded in earnings as they arise. Specifically, the Company is now required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item.

RISK MANAGEMENT

EnCana s results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors.

The Company manages exposure to market risks through the use of various financial instruments and contracts. This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates and enhancing the probability of achieving corporate performance targets.

The following table summarizes the unrecognized gains/(losses) on the Company s risk management activities discussed below.

	Contract Maturity			
($ millions)	**2003**	**2004**	**2005 and beyond**	**Total**
Natural Gas	$ 128	$ 95	$ 79	$ 302
Crude Oil	(99)	(23)		(122)
Gas Storage	(43)			(43)
Natural Gas Liquids	(3)			(3)
Power	(2)		(1)	(3)
Foreign Currency	(72)	(18)		(90)
Interest Rates	26	21	15	62
Total	$ (65)	$ 75	$ 93	$ 103

Commodity Prices

As a means of managing commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts.

Natural Gas

At December 31, 2002, the total unrecognized gain related to all significant natural gas risk management contracts was $302 million, the details of which are outlined below.

Produced Gas

At December 31, 2002, all significant contracts related to produced gas had a total unrecognized gain of $270 million, the details of which are outlined below.

Approximately 244 million cubic feet per day of natural gas has been sold forward under derivative contracts and 9 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of $5.89 per thousand cubic feet. These contracts had an unrecognized loss of $38 million at December 31, 2002.

Approximately 118 million cubic feet per day of natural gas has been sold forward under derivative contracts and 10 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of US$3.52 per million British Thermal Unit. These contracts had an unrecognized loss of $32 million at December 31, 2002.

Approximately 287 million cubic feet of natural gas has been sold forward under derivative contracts at an average NYMEX related price of US$4.10 per million British Thermal Unit for 2003. These contracts had an unrecognized loss of $78 million at December 31, 2002.

Approximately 37 million cubic feet per day of natural gas has been purchased at an average price of $3.24 per thousand cubic feet offsetting the Company s transportation capacity on the Alliance pipeline for 2003. These contracts had an unrecognized gain of $41 million at December 31, 2002.

Approximately 42 million cubic feet per day of natural gas has been sold forward under derivative contracts at an average price of US$3.96 per million British Thermal Unit offsetting the Company s transportation capacity on the Alliance pipeline through October 2003. These contracts had an unrecognized loss of $14 million at December 31, 2002.

Approximately 181 million cubic feet per day of natural gas has been sold forward under derivative contracts through 2007 at an average NYMEX less AECO differential of US$0.49 per million British Thermal Unit. These contracts had an unrecognized gain of $22 million at December 31, 2002.

Approximately 167 million cubic feet per day of natural gas has been sold forward under derivative contracts and 218 million cubic feet per day sold forward under physical contracts for the period January 2003 through 2007 at an average NYMEX less Rockies differential of US$0.48 per million British Thermal Unit. These contracts had an unrecognized gain of $354 million at December 31, 2002.

Approximately 50 million cubic feet per day of natural gas was sold forward through 2007 at an average NYMEX less Rockies differential of US$0.38 per million British Thermal Unit in conjunction with a NYMEX costless collar with a price floor of US$2.46 per million British Thermal Unit and a ceiling price of US$4.90 per million British Thermal Unit. These contracts had an unrecognized gain of $9 million at December 31, 2002.

Approximately 15 million cubic feet per day of natural gas for 2003 has been purchased for fuel use at an average price of $5.15 per thousand cubic feet. These contracts had an unrecognized gain of $6 million at December 31, 2002.

As at January 31, 2003, the Company s Risk Management contracts related to produced gas had an unrecognized gain of $154 million and are outlined below.

Approximately 504 million cubic feet per day of natural gas has been sold forward under derivative contracts and 9 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of $6.28 per thousand cubic feet. In addition, approximately 100 million cubic feet per day has been sold forward under derivative contracts for 2004 at an AECO equivalent of $6.00 per thousand cubic feet.

Approximately 190 million cubic feet per day of natural gas has been sold forward under derivative contracts and 19 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of US$3.57 per million British Thermal Unit.

Approximately 266 million cubic feet of natural gas per day has been sold forward under derivative contracts at an average NYMEX related price of US$4.20 per million British Thermal Unit for 2003. In addition, 50 million cubic feet per day was sold forward under derivative contracts for 2004 at an average NYMEX equivalent of US$4.41 per million British Thermal Unit.

Approximately 37 million cubic feet per day of natural gas has been purchased at an average price of $3.24 per thousand cubic feet, offsetting the Company s transportation capacity on the Alliance pipeline for 2003.

Approximately 42 million cubic feet per day of natural gas has been sold forward under derivative contracts at an average price of US$3.96 per million British Thermal Unit, offsetting the Company s transportation capacity on the Alliance pipeline for 2003.

Approximately 181 million cubic feet per day of natural gas has been sold forward under derivative contracts for the period January 2003 to December 2007 at an average NYMEX less AECO differential of US$0.49 per million British Thermal Unit.

Approximately 167 million cubic feet per day of natural gas has been sold forward under derivative contracts and 218 million cubic feet per day sold forward under physical contracts for the period January 2003 to December 2007 at an average NYMEX less Rockies differential of US$0.48 per million British Thermal Unit.

Approximately 50 million cubic feet per day of natural gas has been sold forward for the period January 2003 to December 2007 at an average NYMEX less Rockies differential of US$0.38 per million British Thermal Unit, in conjunction with a NYMEX costless collar with a price floor of US$2.46 per million British Thermal Unit and a ceiling price of US$4.90 per million British Thermal Unit.

Approximately 15 million cubic feet per day of natural gas has been purchased for fuel use at an average price of $5.15 per thousand cubic feet for 2003.

Purchased Gas

As part of the optimization of Midstream & Marketing assets, the Company has entered into contracts to purchase and sell physical volumes of natural gas. The combination of these purchase and sales transactions creates a closed position. On a combined basis these contracts had an unrecognized gain of $32 million at December 31, 2002.

Crude Oil

At December 31, 2002, all significant contracts related to crude oil had a total unrecognized loss of $122 million, the details of which are outlined below.

Produced Crude Oil

Approximately 85,000 barrels per day in fixed price swaps with an average price of US$25.28 per barrel had been entered into for 2003. The unrecognized loss at December 31, 2002, was $81 million.

Approximately 40,000 barrels per day in costless collars with a price floor of US$21.95 per barrel and a price cap of US$29.00 per barrel had been entered into for 2003. The unrecognized loss at December 31, 2002, was $16 million.

Approximately 62,500 barrels per day in fixed price swaps with an average price of US$23.13 per barrel had been entered into for 2004. The unrecognized loss at December 31, 2002, was $10 million.

Approximately 62,500 barrels per day in costless collars with a price floor of US$20.00 per barrel and a price cap of US$25.69 per barrel had been entered into for 2004. At December 31, 2002, the unrecognized loss related to these contracts was $13 million.

As at January 31, 2003, the unrecognized loss on these contracts was $366 million.

Purchased Crude Oil

As part of its crude oil marketing activities, the Company managed the risk around crude oil inventory and third party margins through the use of futures and options. As at December 31, 2002, the unrecognized loss on these contracts was $2 million. This loss was fully offset by unrealized gains on physical contracts and inventory.

Gas Storage Optimization

Various financial instruments have been entered into for the next 13-month period to manage price volatility relating to the gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. At December 31, 2002, these instruments, on a combined basis, had a net unrecognized loss of $43 million, which was more than offset by unrealized gains on physical inventory in storage.

Natural Gas Liquids

Approximately 315,000 barrels of natural gas liquids in inventory had been sold forward at an average price of US$0.47 per U.S. gallon. The unrecognized loss on these contracts at December 31, 2002, was $1 million.

At December 31, 2002, the Company had sold forward approximately 562,000 barrels of natural gas liquids at fixed prices ranging from US$0.33 per U.S. gallon to US$0.625 per U.S. gallon. The Company had forward purchased approximately 154,000 barrels of natural gas liquids at fixed prices ranging from US$0.44 per U.S. gallon to US$0.54 per U.S. gallon. In addition, call options with strike prices ranging from US$0.36 per U.S. gallon to US$0.50 per U.S. gallon and swap contracts that fixed prices at US$0.4075 per U.S. gallon had also been entered into. The total loss on these risk management activities at December 31, 2002, was $4 million, of which approximately $2 million was recognized in the 2002 financial results.

Power Purchase Arrangements

The Company acquired two electricity contracts in the merger with AEC that expire in 2003 and 2005. These contracts were entered into as part of a cost management strategy. At December 31, 2002, these contracts had an unrecognized loss of $3 million.

Foreign Currency

As a means of managing the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company has entered into foreign exchange contracts in the amount of US$460 million at an average exchange rate of US$0.716 for the period to June 2004. The unrecognized loss with respect to these contracts was $90 million at December 31, 2002.

Interest Rates

The Company has entered into various interest rate and cross currency interest rate swap transactions as a means of managing the interest rate exposure on debt instruments. The unrealized gain with respect to these transactions was $62 million at December 31, 2002.

Credit Risk

The risk of credit losses is minimized through the use of mandated credit policies and procedures designed to limit exposures within acceptable levels. EnCana does not have a significant concentration of credit risk with any single counterparty and no significant bad debts have been incurred or provided for at December 31, 2002.

Operational Risk

Operational risks are managed through a comprehensive insurance program designed to protect the Company from significant losses arising from the risk exposures.

Safety and Environment

Safety and environment risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & 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 an inspection and audit program 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.

OUTLOOK

During 2003, EnCana will continue to focus on growing its natural gas production and storage capacity in North America and oil production in Ecuador to deliver anticipated strong near term growth while building on the U.K. central North Sea and the Gulf of Mexico oil growth platforms for expected medium and longer term value creation. The Company will also continue its efforts to expand on its medium and long-term growth prospects by searching for new growth platforms through new ventures exploration.

The Company s 2003 forecast for produced gas sales is between 3.0 and 3.1 billion cubic feet per day, an increase of approximately 30 percent (11 percent on a pro forma basis) over 2002 levels. Sales volumes for conventional oil and natural gas liquids are forecast to be between 240,000 and 280,000 barrels per day, reflecting an anticipated increase of approximately 26 percent (12 percent on a pro forma basis) over 2002.

The Company expects average natural gas prices in 2003 to improve over 2002 levels. High levels of natural gas in storage resulting from decreased demand negatively impacted natural gas prices in 2002. Prices improved towards the end of 2002, primarily reflecting the impact of declining supply. It is anticipated that improvements in the balance between supply and demand will result in stronger average natural gas prices in 2003.

Volatility in crude oil prices is expected to continue in 2003 as a result of market uncertainties over tensions in the Middle East, political issues in Venezuela, OPEC compliance with production quotas and the overall health of the U.S. economy.

2003 capital investment in core programs is anticipated to be approximately $5 billion before acquisitions and dispositions. The Company expects that it will be able to fund its capital program largely from cash flow, in addition to proceeds received on the disposition of non-core assets. The following table provides details of the anticipated capital expenditures on a divisional basis.

2003 Capital Investment ($ millions)	Exploration	Development	Total
Upstream Conventional			
Onshore North America	$ 350	$ 3,150	$ 3,500
Offshore & International Operations	9	491	500
Offshore & New Ventures Exploration	420	80	500
Total Upstream Conventional	779	3,721	4,500
Midstream & Marketing			500
Total			$ 5,000

EnCana s results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas as well as movements in foreign exchange rates. The following table provides an estimate of the sensitivity of the Company s 2003 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

Sensitivity of 2003 Net Earnings and Cash Flow ($ millions)	Net Earnings	Cash Flow
US$0.01 decrease in the value of the Canadian dollar	$ (20)	$ 70

US$1.00 per barrel increase in the price of WTI	40	60
US$0.25 per million British thermal units increase in the NYMEX gas price	135	200

This estimate is based on management s assumptions used for 2003 planning purposes, as discussed in this section, assumes that Syncrude has been sold and includes the impact of all hedging contracts in effect at January 31, 2003.

February 7, 2003

ENCANA CORPORATION

Consolidated Financial

Statements

For the Year Ended December 31, 2002

MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management s best judgements. Financial information contained throughout the annual report is consistent with these Consolidated Financial Statements.

The policy of the Company is to maintain the highest standard of ethics in all its activities and it has a written ethics and integrity policy. The Company has developed and maintains an extensive system of internal controls that provides reasonable assurance that all transactions are accurately recorded, that the Consolidated Financial Statements realistically report the Company s operating and financial results and that the Company s assets are safeguarded. The Company s Internal Audit department reviews and evaluates the adequacy of and compliance with the Company s internal controls.

The Company s Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the Consolidated Financial Statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange and the Toronto Stock Exchange. The Audit Committee meets at least on a quarterly basis.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company s last annual meeting to audit the Consolidated Financial Statements and provide an independent opinion.

President & Chief Executive Officer	Executive Vice-President & Chief Financial Officer

February 7, 2003

AUDITORS REPORT

TO THE SHAREHOLDERS OF ENCANA CORPORATION

We have audited the consolidated balance sheets of EnCana Corporation as at December 31, 2002 and December 31, 2001 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company s Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and December 31, 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002, in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Calgary, Alberta
Canada

February 7, 2003

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company s financial statements, such as the change described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 7, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors report when the change is properly accounted for and adequately disclosed in the financial statements.

Chartered Accountants
Calgary, Alberta
Canada

February 7, 2003

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended December 31 ($ millions, except per share amounts)		2002	2001	2000
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	*(Note 4)*	$10,011	$4,894	$4,366
EXPENSES	*(Note 4)*			
Transportation and selling		574	172	148
Operating		1,438	693	620
Purchased product		3,448	1,144	1,019
Administrative		187	83	68
Interest, net	*(Note 7)*	419	45	69
Foreign exchange (gain) loss	*(Note 7)*	(20)	20	37
Depreciation, depletion and amortization		2,153	852	772
Gain on corporate disposition	*(Note 6)*	(51)		
		8,148	3,009	2,733
NET EARNINGS BEFORE THE UNDERNOTED		1,863	1,885	1,633
Income tax expense	*(Note 8)*	618	631	633
Distributions on Subsidiary Preferred Securities, net of tax	*(Note 15)*	20		
NET EARNINGS FROM CONTINUING OPERATIONS		1,225	1,254	1,000
NET (LOSS) EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 5)*	(1)	33	21
NET EARNINGS		$ 1,224	$1,287	$1,021
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX	*(Note 16)*	3	4	5
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS		$ 1,221	$1,283	$1,016
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 20)*			
Basic		$ 2.92	$ 4.89	$ 3.94
Diluted		$ 2.87	$ 4.77	$ 3.87
NET EARNINGS PER COMMON SHARE	*(Note 20)*			
Basic		$ 2.92	$ 5.02	$ 4.02
Diluted		$ 2.87	$ 4.90	$ 3.95

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the years ended December 31 ($ millions)		2002	2001	2000
RETAINED EARNINGS, BEGINNING OF YEAR				
As previously reported		$3,689	$ 3,721	$2,788
Retroactive adjustment for change in accounting policy	*(Note 2)*	(59)	(42)	(24)
As restated		3,630	3,679	2,764
Net Earnings		1,224	1,287	1,021
Dividends on Common Shares & Other Distributions, net of tax	*(Note 20)*	(170)	(1,286)	(106)

Other Adjustments	*(Note 20)*		(50)	
RETAINED EARNINGS, END OF YEAR		$4,684	$ 3,630	$3,679

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET

As at December 31 ($ millions)		2002	2001
ASSETS			
Current Assets			
Cash and cash equivalents		$ 212	$ 963
Accounts receivable and accrued revenue		2,052	623
Inventories	*(Note 9)*	543	87
Assets of discontinued operations	*(Note 5)*	1,482	
		4,289	1,673
Capital Assets, net	*(Notes 4, 10)*	23,770	8,162
Investments and Other Assets	*(Note 11)*	377	237
Assets of Discontinued Operations	*(Note 5)*		728
Goodwill	*(Note 3)*	2,886	
	(Note 4)	$31,322	$10,800
LIABILITIES AND SHAREHOLDERS EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,390	$ 824
Income tax payable		14	656
Liabilities of discontinued operations	*(Note 5)*	825	
Short-term debt	*(Note 12)*	438	
Current portion of long-term debt	*(Note 13)*	212	160
		3,879	1,640
Long-Term Debt	*(Note 13)*	7,395	2,210
Deferred Credits and Other Liabilities	*(Note 14)*	585	325
Future Income Taxes	*(Note 8)*	5,212	2,060
Liabilities of Discontinued Operations	*(Note 5)*		586
Preferred Securities of Subsidiary	*(Note 15)*	457	
		17,528	6,821
Shareholders Equity			
Preferred securities	*(Note 16)*	126	126
Share capital	*(Note 17)*	8,732	196
Share options, net	*(Note 3)*	133	
Paid in surplus		61	27
Retained earnings		4,684	3,630
Foreign currency translation adjustment	*(Note 2)*	58	
		13,794	3,979
		$31,322	$10,800

COMMITMENTS AND CONTINGENCIES *(Note 21)*

Approved by the Board

Director	Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31 ($ millions, except per share amounts)		2002	2001	2000
OPERATING ACTIVITIES				
Net earnings from continuing operations		$ 1,225	$ 1,254	$ 1,000
Depreciation, depletion and amortization		2,153	852	772
Future income taxes	*(Note 8)*	667	134	470
Other		(266)	19	36
Cash flow from continuing operations		3,779	2,259	2,278
Cash flow from discontinued operations		42	47	25
Cash flow		3,821	2,306	2,303
Net change in other assets and liabilities		(22)	(63)	(74)
Net change in non-cash working capital from continuing operations	*(Note 20)*	(1,325)	578	2
Net change in non-cash working capital from discontinued operations		97	(47)	(2)
		2,571	2,774	2,229
INVESTING ACTIVITIES				
Business combination with Alberta Energy Company Ltd.	*(Note 3)*	(128)		
Capital expenditures	*(Note 4)*	(4,940)	(1,955)	(1,466)
Proceeds on disposal of capital assets		566	47	193
Corporate (acquisitions) and dispositions	*(Note 6)*	93	84	(948)
Net change in investments and other		64	30	(122)
Net change in non-cash working capital from continuing operations	*(Note 20)*	293	88	42
Discontinued operations		(10)	9	(20)
		(4,062)	(1,697)	(2,321)
FINANCING ACTIVITIES				
Issuance of short-term debt		438	440	469
Repayment of short-term debt			(690)	(219)
Issuance of long-term debt		2,354	1,566	76
Repayment of long-term debt		(1,886)	(399)	(136)
Issuance of common shares	*(Note 17)*	139	48	86
Repurchase of common shares			(7)	(8)
Dividends on common shares	*(Note 20)*	(167)	(1,282)	(101)
Payments to preferred securities holders		(31)	(7)	(9)
Net change in non-cash working capital from continuing operations	*(Note 20)*	(5)	1	
Discontinued operations		(13)		
Other		(82)		
		747	(330)	158
DEDUCT: FOREIGN EXCHANGE (GAIN) LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		7	(19)	1
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(751)	766	65
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		963	197	132
CASH AND CASH EQUIVALENTS, END OF YEAR		$ 212	$ 963	$ 197

CASH FLOW PER COMMON SHARE	*(Note 20)*			
Basic		$ 9.15	$ 9.02	$ 9.11
Diluted		$ 8.99	$ 8.81	$ 8.95
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
Interest paid		$ 416	$ 73	$ 84
Income taxes paid		$ 1,014	$ 34	$ 12

See accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Tabular amounts in Canadian $ millions, unless otherwise indicated

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements include the accounts of EnCana Corporation, formerly PanCanadian Energy Corporation (PanCanadian), and its subsidiaries (EnCana or the Company), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration, production and marketing of natural gas, natural gas liquids and crude oil, as well as natural gas storage operations, natural gas liquids processing and power generation operations.

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called affiliates) and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company s proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which the Company does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements requires that Management make estimates and assumptions and use judgement regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Specifically, amounts recorded for depreciation, depletion, amortization and future dismantlement and site restoration costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the Consolidated Financial Statements of future periods could be material.

C) Revenue Recognition

Revenues associated with the sales of the Company s natural gas, natural gas liquids (NGLs) and crude oil owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

Revenues associated with the sale of transportation and natural gas storage services are recognized when the services are provided.

D) Foreign Currency Translation

In conjunction with the business combination described in Note 3, the Company reviewed its accounting practices for operations outside of Canada and determined that such operations are self-sustaining. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at year end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining foreign operations are included as a separate component of shareholders equity.

Debt payable in U.S. dollars is translated into Canadian dollars at the year end exchange rate, with any resulting adjustment recorded in the Consolidated Statement of Earnings or as a foreign currency translation adjustment in the Consolidated Balance Sheet for self-sustaining operations (see Note 2).

E) Employee Benefit Plans

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management s best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

F) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates with the adjustment being recognized in earnings in the period that the change occurs.

G) Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings less the effect of Distributions on Preferred Securities, net of tax, by the weighted average number of common shares outstanding during the period. Basic cash flow per common share is computed by dividing cash flow by the weighted average number of common shares outstanding during the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

H) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a maturity of three months or less when purchased.

I) Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

J) Capital Assets

Upstream

Conventional The Company accounts for conventional oil and gas properties in accordance with the Canadian Institute of Chartered Accountants guideline on full cost accounting in the oil and gas industry. Under this method, all costs associated with the acquisition of, exploration for, and the development of, natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves, before royalties. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss. Costs of major development projects and exploration on significant unproved properties, together with related land costs, are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred.

A ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proved reserves, plus unimpaired unproved property costs, less future development costs and related production, future dismantlement and site restoration, interest, administrative costs and applicable taxes. The ceiling test calculations utilize the Company s year end sales prices and costs.

Syncrude Capital assets associated with the Syncrude project are accumulated, at cost, in a separate cost centre. Substantially all of these costs are amortized using the unit-of-production method based on the estimated proved developed reserves applicable to the project.

Midstream

Midstream facilities, including gas storage facilities, natural gas liquids extraction plant operations and power generation assets, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

K) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

L) Amortization of Investments and Other Assets

Amortization of deferred items included in Investments and Other Assets is provided for, where applicable, on a straight-line basis over the estimated useful lives of the assets.

M) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by the Company for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company s segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit s assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit s goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

N) Future Dismantlement and Site Restoration Costs

Estimated future dismantlement and site restoration costs of natural gas and crude oil assets are provided for using the unit-of-production method. Such costs for Midstream facilities are provided for over the estimated service lives of the assets. Provisions for future dismantlement and site restoration costs are included in depreciation, depletion and amortization expense in the Consolidated Statement of Earnings. Actual expenditures incurred are charged against the accumulated provision.

O) Stock-based Compensation

The Company does not record compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors.

Obligations for cash payments under the Company s share appreciation rights and deferred share units are accrued as compensation expense over the vesting period. Fluctuations in the price of the Company s common shares will change the accrued compensation expense and are recognized prospectively when they occur.

P) Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company s policy is not to utilize derivative financial instruments for speculative purposes.

The Company formally documents the permitted use of derivative financial instruments and specifically ties their use to the maximization of the netback price of the Company s proprietary production and the optimization of specific assets and obligations. When applicable, the Company also documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategies for undertaking various hedge transactions. This process includes linking these derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also assesses, both at the hedges inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company enters into hedges with respect to a portion of its oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. These transactions generally are swaps, collars or options and are entered into with major financial institutions or commodities trading institutions. Gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related sales occur.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company s total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company also purchases foreign exchange forward contracts to hedge anticipated sales to customers in the United States and the related accounts receivable. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Q) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2002.

NOTE 2 CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Foreign Currency Translation

At January 1, 2002, the Company retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recorded in earnings as they arise. Specifically, the Company is now required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings or as a foreign currency translation adjustment in the Consolidated Balance Sheet for self-sustaining entities. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item.

As required by the standard, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $28 million for the year ended December 31, 2002 (2001 $17 million decrease; 2000 - $18 million decrease). The effect of this change on the December 31, 2001 Consolidated Balance Sheet is an increase in long-term debt and a reduction in deferred credits and other liabilities of $92 million, as well as a reduction in investments and other assets and retained earnings of $59 million (2000 $42 million).

In conjunction with the business combination described in Note 3, the Company reviewed its accounting practices for operations outside of Canada and determined that such operations are self-sustaining. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the operations are deferred and included as a separate component of shareholders equity. Previously, operations outside of Canada were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depreciation, depletion and amortization, which were translated on the same basis as the related assets.

This change in practice was adopted prospectively beginning April 5, 2002, and resulted in an increase in net earnings of $2 million for the year ended December 31, 2002.

NOTE 3 BUSINESS COMBINATION WITH ALBERTA ENERGY COMPANY LTD.

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. (AEC) announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the Arrangement) under the Business Corporations Act (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders and option holders of AEC and the common shareholders of PanCanadian, the Court of Queen s Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation.

This business combination has been accounted for using the purchase method with the results of operations of AEC included in the Consolidated Financial Statements from the date of acquisition. The Arrangement resulted in PanCanadian issuing 218.5 million Common Shares and a transaction value of $8,714 million. The calculation of the purchase price and the allocation to assets and liabilities acquired as of April 5, 2002 is shown below:

Calculation of Purchase Price:		
Common Shares issued to AEC shareholders (millions)	218.5	
Price of Common Shares ($ per common share)	38.43	
Value of Common Shares issued		$ 8,397
Fair value of AEC share options exchanged for share options of EnCana Corporation (Share options)		167
Transaction costs		150
Total purchase price		8,714
Plus: Fair value of liabilities assumed		
Current liabilities		1,781
Long-term debt		4,843
Project financing debt		604
Preferred securities		458
Other non-current liabilities		193
Future income taxes		2,647
Total Purchase Price and Liabilities Assumed		$ 19,240
Fair Value of Assets Acquired:		
Current assets		$ 1,505
Capital assets		14,053
Other non-current assets		605
Goodwill		3,077
Total Fair Value of Assets Acquired		$ 19,240
Goodwill Allocation:		
Onshore North America		$ 2,808
Midstream & Marketing		78
		2,886
Discontinued Operations		191
Total Goodwill Allocation		$ 3,077

NOTE 4 SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

Onshore North America includes the Company s North America onshore exploration for, and production of, natural gas, natural gas liquids and crude oil.

Offshore & International combines the following two divisions:

the Offshore & International Operations Division develops the reserves associated with offshore and international discoveries. The Division currently has production in Ecuador and the U.K. central North Sea and major developments in the East Coast of Canada, Gulf of Mexico and the U.K. central North Sea.

the Offshore & New Ventures Exploration Division includes the Company s exploration activity in the Canadian East Coast, the North American frontier region, the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia and Latin America.

Midstream & Marketing includes gas storage operations, natural gas liquids processing and power generation operations, as well as, marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company s own production.

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations (for the years ended December 31)

	Onshore North America			**Offshore & International**			**Midstream & Marketing**		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Revenues									
Gross revenue	$6,152	$3,569	$3,072	$701	$171	$154	$4,133	$1,462	$1,401
Royalties and production taxes	809	303	259	180					
Revenues, net of royalties and production taxes	5,343	3,266	2,813	521	171	154	4,133	1,462	1,401
Expenses									
Transportation and selling	385	137	123	53	19	9	136	16	16
Operating	952	429	345	135	17	23	351	247	252
Purchased product							3,448	1,144	1,019
Depreciation, depletion and amortization	1,776	703	596	260	96	129	62	20	17
Segment Income	$2,230	$1,997	$1,749	$ 73	$ 39	$ (7)	$ 136	$ 35	$ 97

	Corporate			**Consolidated**		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**
Revenues						
Gross revenue	$ 14	$ (5)	$ (2)	$11,000	$5,197	$4,625
Royalties and production taxes				989	303	259

Revenues, net of royalties and production taxes	14	(5)	(2)	10,011	4,894	4,366
Expenses						
Transportation and selling				574	172	148
Operating				1,438	693	620
Purchased product				3,448	1,144	1,019
Depreciation, depletion and amortization	55	33	30	2,153	852	772
Gain on corporate disposition	(51)			(51)		
Segment Income	10	(38)	(32)	2,449	2,033	1,807
Administrative	187	83	68	187	83	68
Interest, net	419	45	69	419	45	69
Foreign exchange (gain) loss	(20)	20	37	(20)	20	37
	586	148	174	586	148	174
Net Earnings Before Income Tax	(576)	(186)	(206)	1,863	1,885	1,633
Income tax expense	618	631	633	618	631	633
Distributions on Subsidiary Preferred Securities, net of tax	20			20		
Net Earnings from Continuing Operations	$(1,214)	$(817)	$(839)	$ 1,225	$1,254	$1,000

Geographic and Product Information (for the years ended December 31)

ONSHORE NORTH AMERICA	Produced Gas and NGLs					
	Canada			U.S. Rockies		
	2002	2001	2000	2002	2001	2000
Revenues						
Gross revenue	$3,451	$2,544	$1,837	$869	$118	$27
Royalties and production taxes	419	141	105	196	39	9
Revenues, net of royalties and production taxes	3,032	2,403	1,732	673	79	18
Expenses						
Transportation and selling	235	112	98	91		
Operating	407	175	131	64	17	2
Operating Cash Flow	$2,390	$2,116	$1,503	$518	$ 62	$16

	Conventional Crude Oil			Syncrude			Total Onshore North America		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues									
Gross revenue	$1,463	$907	$1,208	$369	$	$	$6,152	$3,569	$3,072
Royalties and production taxes	190	123	145	4			809	303	259
Revenues, net of royalties and production taxes	1,273	784	1,063	365			5,343	3,266	2,813
Expenses									
Transportation and selling	55	25	25	4			385	137	123
Operating	317	237	212	164			952	429	345
Operating Cash Flow	$ 901	$522	$ 826	$197	$	$	$4,006	$2,700	$2,345

OFFSHORE & INTERNATIONAL	Ecuador			U.K. North Sea			Other			Total Offshore & International		
	2002	2001	2000	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues												
Gross revenue	$541	$	$	$160	$171	$154	$	$	$	$701	$171	$154
Royalties and production taxes	180									180		
Revenues, net of royalties and production taxes	361			160	171	154				521	171	154
Expenses												

Transportation and selling	34			19	19	9				53	19	9
Operating	83			18	17	23	34			135	17	23
Operating Cash Flow	$244	$	$	$123	$135	$122	$(34)	$	$	$333	$135	$122

MIDSTREAM & MARKETING	**Midstream**			**Marketing**			**Total Midstream & Marketing**		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
Revenues									
Gross revenue	$760	$260	$311	$3,373	$1,202	$1,090	$4,133	$1,462	$1,401
Expenses									
Transportation and selling				136	16	16	136	16	16
Operating	331	228	229	20	19	23	351	247	252
Purchased product	265			3,183	1,144	1,019	3,448	1,144	1,019
Operating Cash Flow	$164	$ 32	$ 82	$ 34	$ 23	$ 32	$ 198	$ 55	$ 114

Capital Expenditures

Years ended December 31	2002	2001	2000
Onshore North America	$3,662	$1,356	$1,071
Offshore & International	1,126	407	266
Midstream & Marketing	87	165	90
Corporate	65	27	39
Total	$4,940	$1,955	$1,466

Additions to Goodwill

The only additions to goodwill during the year were as a result of the business combination transaction described in Note 3.

Capital Assets and Total Assets

As at December 31	Capital Assets		Total Assets	
	2002	2001	2002	2001
Onshore North America	$18,994	$6,442	$22,977	$ 6,970
Offshore & International	3,710	1,154	4,023	1,247
Midstream & Marketing	874	458	2,348	849
Corporate	192	108	492	1,006
Assets of Discontinued Operations			1,482	728
Total	$23,770	$8,162	$31,322	$10,800

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $2,093 million (2001 $1,216 million; 2000 - $1,063 million).

Major Customers

The Company does not rely on any one customer for 10 percent of its consolidated Revenues, Net of Royalties and Production Taxes.

All of the Company s crude oil produced in Ecuador is sold to a single marketing company. All payments are secured by letters of credit from a major financial institution.

NOTE 5 DISCONTINUED OPERATIONS

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations.

On July 9, 2002, the Company announced that it planned to sell its 70% equity investment in the Cold Lake Pipeline System and its 100% interest in the Express Pipeline System. Both crude oil pipeline systems were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002 described in Note 3. Accordingly, these operations have been accounted for as discontinued operations. The Company, through indirect wholly owned subsidiaries, is a shipper on the Express system and the Cold Lake pipeline. The financial results for the year ended December 31, 2002, shown below, include tariff revenue of $54 million paid by the Company for services on Express. On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines operations for approximately $1.6 billion including the assumption of long-term debt (see Note 22).

As the wind-down of the merchant energy operation was substantially complete at December 31, 2002, and the midstream pipelines were sold subsequent to year end, all discontinued operations at December 31, 2002 have been classified as current on the Consolidated Balance Sheet.

For comparative purposes, the following tables present the effect of only the Merchant Energy discontinued operations on the Consolidated Financial Statements for the years ended December 31, 2001 and 2000. It does not include any financial information related to Midstream Pipelines for those years as EnCana did not own the pipelines being discontinued at that time.

Consolidated Statement of Earnings

For the years ended December 31	Merchant Energy			Midstream - Pipelines			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues	$1,454	$4,085*	$3,025	$212	$	$	$1,666	$4,085	$3,025
Expenses									
Operating				78			78		
Purchased product	1,465	3,983*	2,961				1,465	3,983	2,961
Administrative	35	43	26				35	43	26
Interest, net				30			30		
Foreign exchange (gain)				(3)			(3)		
Depreciation, depletion and amortization		4	3	27			27	4	3
Loss on discontinuance	30						30		
	1,530	4,030	2,990	132			1,662	4,030	2,990
Net (Loss) Earnings Before Income Tax	(76)	55	35	80			4	55	35
Income tax (recovery) expense	(27)	22	14	32			5	22	14
Net (Loss) Earnings from Discontinued Operations	$ (49)	$ 33	$ 21	$ 48	$	$	$ (1)	$ 33	$ 21

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as Revenues and Expenses - Purchased product. The amendment had no effect on net earnings or cash flow but Revenues and Expenses Purchased product have been reduced by $1,126 million.

Consolidated Balance Sheet

As at December 31	Merchant Energy		Midstream - Pipelines		Total	
	2002	2001	2002	2001	2002	2001
Assets						
Cash and cash equivalents	$	$	$ 68	$	$ 68	$
Accounts receivable and accrued revenue		632	31		31	632
Inventories		70	1		1	70
		702	100		100	702
Capital assets, net		9	817		817	9
Investments and other assets		17	374		374	17
Goodwill			191		191	
		728	1,482		1,482	728
Liabilities						
Accounts payable and accrued liabilities	5	584	40		45	584
Income tax payable			17		17	

Current portion of long-term debt			23		23	
	5	584	80		85	584
Long-term debt			576		576	
Deferred credits and other liabilities		2				2
Future income taxes			164		164	
	5	586	820		825	586
Net Assets of Discontinued Operations	$ (5)	$ 142	$ 662	$	$ 657	$ 142

NOTE 6 CORPORATE (ACQUISITIONS) AND DISPOSITIONS

Years ended December 31	2002	2001	2000
Acquisitions*			
Montana Power	$	$	$ (689)
Scott and Telford			(259)
Other		(72)	
		(72)	(948)
Dispositions	93	156	
	$ 93	$ 84	$ (948)

* Acquisitions include all corporate acquisitions other than the business combination described in Note 3.

In December 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $93 million, with a gain on disposal of $51 million.

During 2000, the Company purchased the petroleum and natural gas exploration and production and midstream and marketing divisions of The Montana Power Company. The acquisition was accounted for by the purchase method, with the results reflected in the Company s operations from November 1, 2000.

During 2000, the Company purchased interests in the Scott (13.5%) and Telford lands on block 15/22 (26%) surrounding the Scott/Telford producing unit. The acquisition was accounted for by the purchase method, with the results reflected in the Company s operations from January 7, 2000.

These acquisitions have been accounted for as follows:

	Montana Power	Scott and Telford
Net Assets Acquired		
Working capital	$ (66)	$ 4
Capital assets	790	283
Other assets	77	
Future income taxes	(91)	(28)
Site restoration costs assumed	(21)	
Cash Consideration Paid	$689	$259

NOTE 7 INTEREST, NET AND FOREIGN EXCHANGE (GAIN) LOSS

Interest, Net

Years ended December 31	2002	2001	2000
Interest Expense Long-term Debt	$358	$ 80	$ 84
Early Retirement of Long-term Debt	54		
Interest Expense Other	18		
Interest Income	(11)	(35)	(15)
	$419	$ 45	$ 69

The Company has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2002 by $28 million (2001 $15 million; 2000 $6 million).

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
5.50% due on March 17, 2003 $100 million	US$71 million	C$ Fixed	US$ Floating*	3 month LIBOR less 68 basis points
5.80% due June 2, 2008 $225 million	US$71 million C$125 million	C$ Fixed C$ Fixed	US$ Fixed* C$ Floating	4.80%

				3 month Bankers Acceptance less 5 basis points
7.50% due August 25, 2006 $100 million	US$73 million	C$ Fixed	US$ Fixed*	4.14%
8.40% due December 15, 2004 $100 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 41 basis points
8.75% due November 9, 2005	US$73 million	C$ Fixed	US$ Fixed*	4.99%
$200 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 4 basis points

* These instruments have been subject to multiple swap transactions.

Foreign Exchange (Gain) Loss

Years ended December 31	2002	2001	2000
Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt	$ (34)	$ 55	$ 36
Other Foreign Exchange (Gains) Losses	14	(35)	1
	$ (20)	$ 20	$ 37

NOTE 8 INCOME TAXES

Years ended December 31	2002	2001	2000
Provision for Income Taxes			
Current			
Canada	$ (30)	$504	$174
United States	(49)	(9)	(11)
Ecuador	27		
United Kingdom			
Other	3	2	
	(49)	497	163
Future	667	134	470
	$618	$631	$633

The net future income tax liability is comprised of:

As at December 31	2002	2001
Future Tax Liabilities		
Capital assets in excess of tax values	$4,829	$1,903
Timing of partnership items	809	292
Future Tax Assets		
Net operating losses carried forward	(320)	(135)
Other	(106)	
Net Future Income Tax Liability	$5,212	$2,060

The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

Years ended December 31	2002	2001	2000
Net Earnings Before Income Taxes	$1,863	$1,885	$1,633
Canadian Statutory Rate	42.3%	42.8%	44.7%
Expected Income Taxes	788	807	730
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	232	113	104
Canadian resource allowance	(331)	(258)	(245)
Large corporations tax	35	16	16
Statutory rate differences	(57)	(19)	9
Effect of tax rate changes	(33)	(81)	
Other	(16)	53	19
	$ 618	$ 631	$ 633
Effective Tax Rate	33.2%	33.5%	38.8%

The approximate amounts of tax pools available are as follows:

As at December 31	2002	2001
Canada	$ 7,364	$2,726
United States	3,435	966
Ecuador	1,312	
United Kingdom	195	148
	$12,306	$3,840

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a later year end than the Company.

NOTE 9 INVENTORIES

As at December 31	2002	2001
Product		
Onshore North America	$ 45	$ 3
Offshore & International	9	
Midstream & Marketing	377	67
Parts, Supplies and Other	112	17
	$543	$87

NOTE 10 CAPITAL ASSETS

As at December 31	2002			2001		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Onshore North America						
Canada conventional	$21,107	$(7,254)	$13,853	$11,790	$(5,936)	$5,854
U.S. conventional	4,133	(406)	3,727	643	(55)	588
Syncrude	1,440	(26)	1,414			
Total Onshore North America	26,680	(7,686)	18,994	12,433	(5,991)	6,442
Offshore & International						
Ecuador	1,658	(115)	1,543			
United Kingdom	695	(208)	487	516	(136)	380
Other	2,019	(339)	1,680	1,018	(244)	774
Total Offshore & International	4,372	(662)	3,710	1,534	(380)	1,154
Midstream & Marketing	1,005	(131)	874	569	(111)	458
Corporate	302	(110)	192	202	(94)	108
	$32,359	$(8,589)	$23,770	$14,738	$(6,576)	$8,162

* Depreciation, depletion and amortization

Included in Midstream is $75 million (2001 nil) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Administrative costs are not capitalized as part of the capital expenditures in Onshore North America and Offshore & International.

At December 31, 2002, costs in respect of significant unproved properties and major development projects excluded from depletable costs were:

	2002	2001	2000
Onshore North America	$ 829	$110	$ 23

Offshore & International	1,110	624	450
	$1,939	$734	$473

The prices used in the ceiling test evaluation of the Company s conventional oil and natural gas reserves at December 31, 2002, were:

Onshore North America		
Canada		
Natural gas	($ per thousand cubic feet)	6.05
Crude oil	($ per barrel)	30.29
Natural gas liquids	($ per barrel)	34.76
U.S. Rockies		
Natural gas	(US$ per thousand cubic feet)	3.14
Crude oil	(US$ per barrel)	31.23
Natural gas liquids	(US$ per barrel)	26.52
Offshore & International		
Ecuador crude oil	(US$ per barrel)	21.62
U.K. natural gas	(US$ per thousand cubic feet)	3.06
U.K. crude oil	(US$ per barrel)	25.66
U.K. natural gas liquids	(US$ per barrel)	24.19

NOTE 11 INVESTMENTS AND OTHER ASSETS

As at December 31		2002	2001
Equity Investments	*(Note A)*	$ 98	$ 22
Value Added Tax Recoverable		89	
Marketing Contracts		43	48
Deferred Financing Costs		44	38
Deferred Pension Costs		23	33
Other		80	96
		$377	$237

A) Included in Equity Investments is the following:

i. A 36% indirect equity investment in Oleoducto Trasandino, which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile.

ii. A 31% indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd., which is the owner of a crude oil pipeline, currently under construction in Ecuador, that will ship crude oil from the producing areas of Ecuador to a new export marine terminal.

Summary financial information for the Company s share of these equity investments, on a combined basis, is as follows:

Years ended December 31	2002	2001
Current Assets	$ 76	$
Non-current Assets	509	
Current Liabilities	49	
Non-recourse Debt	446	
Non-current Liabilities	3	
Revenues	$ 35	$
Net Earnings	18	
Equity Earnings (included in Midstream Revenues)	$ 9	$

NOTE 12 SHORT-TERM DEBT

At December 31, 2002, one of the Company s subsidiaries had in place short-term debt of $438 million. The borrowing is under a non-revolving credit facility, which has an expiry date of May 2003 with a provision for an extension for a further six months at the option of the lender and upon the request from the subsidiary. This facility was repaid in full subsequent to year end and then cancelled.

NOTE 13 LONG-TERM DEBT

As at December 31		2002	2001
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*(Note B)*	$1,388	$ 37
Unsecured notes and debentures	*(Note C)*	1,825	125
		3,213	162
U.S. Dollar Denominated Debt			

U.S. revolving credit and term loan borrowings	*(Note D)*	696	
U.S. unsecured notes and debentures	*(Note E)*	3,608	2,208
		4,304	2,208
Increase in Value of Debt Acquired	*(Note F)*	90	
Current Portion of Long-term Debt	*(Note G)*	(212)	(160)
		$7,395	$2,210

A) Overview

Revolving credit and term loans

At December 31, 2002, the Company had in place revolving credit and term loan facilities for $4.25 billion. One of the facilities, totalling $4 billion, consists of two tranches of $2 billion each. One tranche is fully revolving for a 364-day period with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, this tranche converts to a non-revolving reducing loan for a term of one year. The second tranche is fully revolving for a period of three years from the date of the agreement, December 2002. The facility is unsecured and bears interest at either the lenders rates for Canadian prime commercial loans, U.S. base rate loans, Bankers Acceptances rates, or at LIBOR plus applicable margins. The other credit facility, in the amount of $250 million, was cancelled subsequent to year-end.

At December 31, 2002, the Company s subsidiaries had in place two unsecured credit facilities totalling $143 million. The facilities are unsecured and fully revolving for a 364-day period with a provision for extensions at the option of the lenders and upon notice from the respective subsidiary. If not extended, the facilities convert to non-revolving reducing loans for terms of 3 and 5 years, respectively. These facilities bear interest at either the lenders rates for Canadian prime commercial loans, U.S. base rate loans, Bankers Acceptances rates, or at LIBOR plus applicable margins.

One of the Company s partnerships has a credit agreement, consisting of a term loan facility, senior secured notes and a levelization account, relating to the construction of a cogeneration plant. The term loan bears interest at the prevailing prime lending rate plus 0.25%. The notes bear interest at the prevailing prime lending rate plus 1.25%. The partnership also has an option under the credit agreement to use an average Bankers Acceptances rate plus a margin that will vary during the term. The levelization account accumulates interest at the yield rate of the most recent Government of Canada bond issue with a 20-year maturity as of January 20th each year. The term loan and senior notes are secured by the project facilities.

Revolving credit and term loan borrowings include Bankers Acceptances and Commercial Paper of $1,376 million (2001 nil) maturing at various dates with a weighted average interest rate of 3.04%. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2002 relating to revolving credit and term loan agreements were approximately $4 million (2001 $1 million).

Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company s current medium term note program was renewed in 2002 with $700 million unutilized at December 31, 2002. The notes may be denominated in Canadian dollars, or in foreign currencies.

The Company has in place a shelf prospectus for U.S. Unsecured Notes in the amount of US$2.0 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue.

B) Revolving Credit and Term Loan Borrowings

	2002	2001
Bankers Acceptances	$ 435	$
Commercial Paper	916	
Cogeneration Facility, matures March 31, 2016	37	37
	$1,388	$37

C) Unsecured Notes and Debentures

	2002	2001
8.15% due July 31, 2003	$ 100	$
6.60% due June 30, 2004	50	
7.00% due December 1, 2004	100	
5.95% due October 1, 2007	200	
5.30% due December 3, 2007	300	
5.95% due June 2, 2008	100	
5.80% due June 2, 2008	125	125
5.80% due June 19, 2008	100	
6.10% due June 1, 2009	150	
7.15% due December 17, 2009	150	
8.50% due March 15, 2011	50	
7.10% due October 11, 2011	200	
7.30% due September 2, 2014	150	
5.50%/6.20% due June 23, 2028	50	
	$ 1,825	$ 125

D) U.S. Revolving Credit and Term Loan Borrowings

	US$ Amount	2002	2001
Commercial Paper	$ 16	$ 25	$
LIBOR Loan	425	671	
	$ 441	$ 696	$

E) U.S. Unsecured Notes and Debentures

	US$ Amount	2002	2001
Floating Rate			
5.50% due March 17, 2003	$ 71*	$ 112	113
8.40% due December 15, 2004	73*	116	117
8.75% due November 9, 2005	73*	115	117
Fixed Rate			
7.90% due January 24, 2002			80
8.10% due May 22, 2002			80
8.75% due November 9, 2005	73*	115	116
7.50% due August 25, 2006	73*	115	116
5.80% due June 2, 2008	71*	112	113
7.65% due September 15, 2010	200	316	
6.30% due November 1, 2011	500	790	798
8.125% due September 15, 2030	300	474	
7.20% due November 1, 2031	350	553	558
7.375% due November 1, 2031	500	790	

$2,284	$3,608	$2,208

* The Company has entered into a series of cross-currency and interest rate swap transactions that effectively convert these notes to U.S. dollars. The effective U.S. dollar principal is shown in the table.

F) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in the business combination described in Note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 24 years.

G) Current Portion of Long-term Debt

	2002	2001
7.90% Medium Term Note due January 24, 2002	$	$ 80
8.10% Debenture due May 22, 2002		80
5.50% Medium Term Note due March 17, 2003	112	
8.15% Debenture due July 31, 2003	100	
	$212	$160

H) Mandatory Five Year Debt Payments

2003	2004	2005	2006	2007	Thereafter	Total
$212	$266	$230	$115	$500	$6,194	$7,517

The amount due in 2003 excludes Bankers Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

NOTE 14 DEFERRED CREDITS AND OTHER LIABILITIES

As at December 31	2002	2001
Future Dismantlement and Site Restoration Costs	$494	$255
Other	91	70
	$585	$325

NOTE 15 PREFERRED SECURITIES OF SUBSIDIARY

	Rate (%)	Currency	Principal Amount	Maturity Date
Preferred Securities	8.50	Canadian	$ 200	September 30, 2048
Preferred Securities	9.50	U.S	$ 150	September 30, 2048

The Preferred Securities of Subsidiary are unsecured junior subordinated debentures. Subject to certain conditions, the Company s subsidiary, Alberta Energy Company Ltd., has the right to defer payments of interest on the securities for up to 20 consecutive quarterly periods. The subsidiary may satisfy its obligation to pay deferred interest or the principal amount by delivering sufficient equity securities to the Trustee. The Preferred Securities of Subsidiary were acquired in the business combination described in Note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount is being amortized over the remaining life of the Preferred Securities of Subsidiary.

The Company recognized $31 million ($20 million, net of tax) for distributions on the Preferred Securities of Subsidiary in 2002.

On January 1, 2003, the Company and its subsidiary were amalgamated, and as a result, these Preferred Securities became the direct obligation of EnCana Corporation and they will be included in shareholders equity in future periods (see Note 22).

NOTE 16 PREFERRED SECURITIES

On March 23, 1999, the Company issued $126 million of Coupon Reset Subordinated Term Securities Series A due March 23, 2034. Interest is payable semi-annually at a rate of 7% per annum for the first five years and is reset at the Five Year Government of Canada Yield plus 2% on each fifth anniversary of the date of issuance. The securities are redeemable by the Company, in whole or in part, at any time on or after March 23, 2004, at par plus accrued and unpaid interest. The Company has the right to defer, subject to certain conditions, interest for a period of up to five years. The Company may also satisfy its obligation to pay deferred interest, the redemption amount, or the principal amount by delivering sufficient common shares, preferred shares, or other non-redeemable preferred shares to the Trustee.

With respect to the Preferred Securities, the Company entered a series of option transactions that result in an effective floating interest rate equal to three-month Bankers Acceptances rate plus 104 basis points on $126 million.

The Company recognized $5 million ($3 million, net of tax) for distributions on the Preferred Securities in 2002 compared with $7 million ($4 million, net of tax) in 2001 and $9 million ($5 million, net of tax) in 2000. These distributions, net of tax, have been recorded as a direct charge to retained earnings.

NOTE 17 SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

As at December 31		2002		2001	
		Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year		254.9	$ 196	254.8	$ 148
Shares Issued to AEC Shareholders	*(Note 3)*	218.5	8,397		
Shares Issued under Option Plans		5.5	139	1.9	48
Shares Repurchased				(0.2)	
Adjustments due to Canadian Pacific Limited Reorganization				(1.6)	
Common Shares Outstanding, End of Year		478.9	$ 8,732	254.9	$ 196

Effective October 16, 2002, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid. Under the bid, the Company may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. On October 22, 2002, the Company became entitled to make purchases under the bid for a period of up to one year.

During 2001, the Company implemented a small shareholder-selling program that enabled shareholders that owned 99 or fewer Common Shares of the Company as of October 5, 2001, to sell their shares without incurring any brokerage commission. The program expired on March 5, 2002.

In 2001 and 2000, 0.2 million and 0.3 million Common Shares were repurchased for $7 million and $8 million, respectively. The cost of the repurchases was substantially charged to Paid in Surplus. No Common Shares were repurchased in 2002.

Stock Options

The Company has a stock-based compensation plan (EnCana plan) that allows employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous EnCana and Canadian Pacific Limited (CPL) replacement plans expire 10 years from the date the options were granted.

In conjunction with the business combination transaction described in Note 3, options to purchase AEC common shares were replaced with options to purchase Common Shares of EnCana (AEC replacement plan) in a manner consistent with the provisions of the AEC stock option plan. Options granted under the AEC plan prior to April 21, 1999 expire after seven years and options granted after April 20, 1999 expire after five years. The business combination resulted in these replacement options, along with all options outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase common shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. Option exercise prices approximate the market price for the common shares on the date the options are issued. In the event of a change in control of the Company, all outstanding options become immediately exercisable.

CPL Replacement Plan

As part of the CPL reorganization, as described in Note 20, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL s stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and, as a result of the reorganization, are all exercisable.

Directors Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors are given an initial grant of 15,000 options to purchase Common Shares of the Company. Thereafter, there is an annual grant of 7,500 options to each non-employee director. These options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date.

The following tables summarize the information about options to purchase Common Shares:

As at December 31	2002		2001	
	Stock Options	Weighted Average Exercise Price ($)	Stock Options	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	10.5	32.31	6.9	22.61
Granted under EnCana Plan	12.1	48.13	4.5	48.08
Granted under CPL Replacement Plan			1.5	22.83
Granted under AEC Replacement Plan	13.1	32.01		
Granted under Directors Plan	0.1	48.04	0.1	39.60
Exercised	(5.5)	25.20	(1.9)	25.82
Forfeited	(0.7)	43.81	(0.6)	37.04
Outstanding, End of Year	29.6	39.74	10.5	32.31
Exercisable, End of Year	17.7	34.10	3.2	22.92

As at December 31, 2002	Outstanding Options			Exercisable Options	
Range of Exercise Price ($)	Number of Options Outstanding (millions)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Number of Options Outstanding (millions)	Weighted Average Exercise Price ($)
13.50 to 19.99	3.5	1.3	18.75	3.5	18.75
20.00 to 24.99	2.1	2.3	22.25	2.1	22.25
25.00 to 29.99	3.2	2.3	26.58	3.2	26.58
30.00 to 43.99	1.9	3.1	38.56	1.7	38.11
44.00 to 53.00	18.9	3.9	47.91	7.2	47.42
	29.6	3.0	39.74	17.7	34.10

At December 31, 2002, there were 12.8 million Common Shares reserved for issuance under stock option plans (2001 2.9 million).

The Company does not record compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors. If the fair-value method had been used, the Company s Net Earnings and Net Earnings per Common Share would approximate the following pro forma amounts:

Years ended December 31 ($ millions, except per share amounts)	2002	2001
Compensation Costs	$ 80	$ 39
Net Earnings		
As reported	1,224	1,287
Pro forma	1,144	1,248
Net Earnings per Common Share		
Basic		
As reported	2.92	5.02
Pro forma	2.73	4.87
Diluted		
As reported	2.87	4.90
Pro forma	2.68	4.75

As described above, the acquisition of AEC resulted in all outstanding options at April 5, 2002 becoming fully exercisable. As the stock option expense is normally recognized over the expected life, the early vesting of outstanding options resulted in an acceleration of the compensation cost. As such, a $33 million expense relating to options outstanding at April 5, 2002 was included in the 2002 pro forma earnings above.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

Years ended December 31	2002	2001
Weighted Average Fair Value of Options Granted	$13.31	$13.53
Risk-free Interest Rate	4.29%	4.24%
Expected Lives (years)	3.00	3.00
Expected Volatility	0.35	0.35
Annual Dividend per Share	$ 0.40	$ 0.40

NOTE 18 COMPENSATION PLANS

Pensions

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits to substantially all of its employees. The Syncrude joint venture (Syncrude) has post- retirement benefits plans for its employees. All of the information pertaining to Syncrude in this note represents the Company s proportionate interest.

The total expense for the defined contribution plans is as follows:

Years ended December 31	2002	2001	2000
EnCana Corporation	$14	$9	$6

Information about defined benefit post-retirement benefit plans in aggregate, is as follows:

	EnCana Corporation		Syncrude
As at December 31	2002	2001	2002
Accrued Benefit Obligation, Beginning of Year	$ 135	$ 115	$
Plan acquisition	87	4	122
Current service cost	6	3	4
Interest cost	14	8	6
Benefits paid	(10)	(7)	(3)
Actuarial loss	15	8	
Contributions			
Special termination benefits	3		
Changes as a result of curtailment	1		
Plan amendments	13	4	
Accrued Benefit Obligation, End of Year	$ 264	$ 135	$ 129

	EnCana Corporation		Syncrude
As at December 31	2002	2001	2002

Fair Value of Plan Assets, Beginning of Year	$ 133	$ 144	$
Plan acquisition	83	3	75
Transfers to defined contribution plan	(9)	(9)	
Actual return on plan assets	(15)	1	(5)
Employer contributions	1	1	3
Employees contributions			
Benefits paid	(8)	(7)	(3)
Fair Value of Plan Assets, End of Year	$ 185	$ 133	$ 70
Funded Status Plan (Deficit) Surplus	$ (79)	$ (2)	$ (59)
Unamortized Net Actuarial Loss	80	30	45
Unamortized Past Service Cost	16	4	
Net Transitional (Asset) Liability	(15)	(18)	
Accrued Benefit Asset (Liability)	$ 2	$ 14	$ (14)

Included in the above accrued benefit obligation and fair value of plan assets at year-end for EnCana Corporation are unfunded benefit obligations of $54 million (2001 $31 million) related to three of the Company s defined benefit pension plans and the other post retirement benefit plans.

The significant actuarial assumptions used to determine the periodic expense and accrued benefit obligations are as follows:

	EnCana Corporation		Syncrude
Years ended December 31	**2002**	**2001**	**2002**
Discount Rate	6.5%	6.5%	6.5%
Expected Long-term Rate of Return on Plan Assets	7.0%	7.0%	9.0%
Rate of Compensation Increase	3.5%	4.0%	4.0%

The periodic expense for EnCana Corporation employee benefits is as follows:

Years ended December 31	**2002**	**2001**	**2000**
Current Service Cost	$ 5	$ 3	$ 2
Interest Cost	13	8	7
Expected Return on Plan Assets	(12)	(10)	(10)
Amortization of Net Actuarial Gain	2		
Amortization of Transitional Obligation	(3)	(3)	(2)
Amortization of Past Service Cost	1	1	
Curtailment Loss	2		
Special Termination Benefits	3		
Expense for Defined Contribution Plan	14	9	6
Net Benefit Plan Expense	$ 25	$ 8	$ 3

The average remaining service period of the active employees covered by the pension plans is nine years. The average remaining service period of the active employees covered by the other retirement benefit plans is 12 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

The periodic expense for Syncrude employee benefits is as follows:

Years ended December 31	**2002**	**2001**	**2000**
Current Service Cost	$ 4	$	$
Interest Cost	6		
Expected Return on Plan Assets	(5)		
Amortization of Net Actuarial Gain	1		
Expense for Defined Contribution Plan			
Net Benefit Plan Expense	$ 6	$	$

The average remaining service period of the active employees covered by the defined benefit plans is 13 years.

Share Appreciation Rights

The Company has in place a program whereby certain employees are granted Share Appreciation Rights (SAR s) which entitle the employee to receive a cash payment equal to the excess of the market price of the Company s Common Shares at the time of exercise over the exercise price of the right. In conjunction with the business combination transaction described in Note 3, outstanding AEC SAR s were replaced by EnCana SAR s. SAR s granted expire after five years. The business combination resulted in these replacement SAR s, along with all SAR s previously issued by EnCana, becoming exercisable after the close of business on April 5, 2002.

The following tables summarize the information relating to SAR s:

As at December 31, 2002	Outstanding SAR's	Weighted Average Exercise Price ($)
Canadian Dollar Denominated (C$)		
Outstanding, beginning of year		
Granted	600,000	38.35
Acquired April 5, in AEC acquisition	2,637,421	30.70
Exercised	(648,902)	27.67
Forfeited	(303,618)	39.08
Outstanding, end of year	2,284,901	35.56
Exercisable, end of year	2,284,901	35.56
U.S. Dollar Denominated (US$)		
Outstanding, beginning of year		
Acquired April 5, in AEC acquisition	1,711,095	28.32
Exercised	(223,703)	26.33
Forfeited	(140,955)	29.88
Outstanding, end of year	1,346,437	28.52
Exercisable, end of year	1,346,437	28.52

As at December 31, 2002	SAR's Outstanding		
Range of Exercise Price ($)	Number of SAR's	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)
Canadian Dollar Denominated (C$)			
10.00 to 19.99	24,643	0.03	15.63
20.00 to 29.99	966,319	2.04	26.74
30.00 to 39.99	622,080	4.09	38.26
40.00 to 49.99	657,512	3.19	46.38
50.00 to 60.00	14,347	3.32	51.37
	2,284,901	2.92	35.56
U.S. Dollar Denominated (US$)			
20.00 to 29.99	688,889	3.11	26.72
30.00 to 40.00	657,548	3.20	30.41
	1,346,437	3.15	28.52

During the year, the Company recorded compensation costs of $7 million related to the outstanding SAR s.

Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units (DSU s) which are equivalent in value to a Common Share of the Company. DSU s granted to Directors vest immediately. DSU s granted to Senior Executives in 2002 vest over a three year period.

The following table summarizes the information relating to the DSU s:

As at December 31, 2002	**Outstanding DSU's**	**Average Share Price ($)**
Outstanding, Beginning of Year		
Acquired April 5, in AEC acquisition	29,631	47.29
Granted, Directors	22,500	49.75
Granted, Senior Executives	260,000	49.75
Exercised	(2,964)	48.00
Outstanding, End of Year	309,167	48.69
Exercisable, End of Year	49,167	48.20

During the year, the Company recorded compensation costs of $6 million related to the outstanding DSU s.

NOTE 19 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities are as follows:

As at December 31		2002	2001
Commodity Price Risk	*(Note A)*		
Natural gas		$ 302	$ 145
Crude oil		(122)	12
Gas storage optimization		(43)	
Natural gas liquids		(3)	
Power		(3)	
Foreign Currency Risk	*(Note B)*	(90)	(187)
Interest Rate Risk	*(Note C)*	62	9
		$ 103	$ (21)

A) Commodity Price Risk

Natural Gas

At December 31, 2002, the fair value of financial instruments that related to the corporate gas risk management activities was $51 million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Term	Price		Unrecognized Gain/(Loss) (Cdn$)
Fixed AECO Price (Cdn$)	244	2003	5.89	C$/mcf	$ (37)
Fixed AECO Price (US$)	118	2003	3.54	US$/mmbtu	(29)
NYMEX Fixed Price	287	2003	4.10	US$/mmbtu	(78)
Alliance Pipeline Mitigation	42	2003	3.96	US$/mmbtu	(14)
Fixed NYMEX to AECO Basis	181	2003-2007	(0.49)	US$/mmbtu	22
Fixed NYMEX to Rockies Basis	167	2003-2007	(0.47)	US$/mmbtu	187
					$ 51

The unrecognized gain on the physical contracts is $219 million.

The fair value of the financial instruments that related to the gas marketing activities was an unrecognized gain of $9 million. These activities are part of the ongoing operations of the Company s proprietary production management and the financial transactions are directly related to physical sales. The corresponding physical deals have an unrecognized gain of $23 million.

Crude Oil

As at December 31, 2002, the Company s corporate oil risk management activities had an unrecognized loss of $120 million. The contracts were as follows:

	Notional Volumes		Average Price	Unrecognized Gain/(Loss)

	(bbl/d)	Term	(US$/bbl)	(Cdn$)
Fixed WTI NYMEX Price	85,000	2003	25.28	$ (81)
Fixed WTI NYMEX Price	62,500	2004	23.13	(10)
Collars on WTI NYMEX	40,000	2003	21.95-29.00	(16)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(13)
				$ (120)

As at December 31, 2002, the crude oil marketing activities had an unrecognized loss of $2 million on their financial contracts, which were offset by unrecognized gains on physical inventory.

Gas Storage Optimization

As part of the Company s gas storage optimization program, the Company has entered into financial instruments at various locations and terms over the next 13 months to manage the price volatility of the corresponding physical transactions and inventories.

As at December 31, 2002, the unrecognized loss on financial instruments was $40 million, which was as follows:

	Notional Volumes (bcf)	Price (US$/mcf)	Unrecognized Gain/(Loss) (Cdn$)
Purchases	102.4	4.49	$ 64
Sales	115.2	4.33	(104)
			$ (40)

The unrecognized loss on physical contracts was $3 million. The total unrecognized loss of $43 million was more than offset by unrealized gains on physical inventory in storage.

Natural Gas Liquids

Inventory of 315,000 barrels of natural gas liquids has been sold forward at an average price of US$0.47 per U.S. gallon. As at December 31, 2002, the unrecognized loss on these contracts was $1 million.

As at December 31, 2002, the Company had sold call options with strike prices ranging from US$0.36 per U.S. gallon to US$0.50 per U.S. gallon. It also entered into swap contracts that fixed prices at US$0.4075 per U.S. gallon. The total loss of these financial instruments at December 31, 2002 was $2 million, of which approximately $1 million has been recognized.

In addition, the Company had entered into physical contracts that sold forward approximately 562,000 barrels of natural gas liquids at fixed prices ranging from US$0.33 per U.S. gallon to US$0.625 per U.S. gallon and purchased approximately 154,000 barrels of natural gas liquids at fixed prices ranging from US$0.44 per U.S. gallon to US$0.54 per U.S. gallon. The total loss on these contracts at December 31, 2002 was $2 million, of which approximately $1 million has been recognized in the financial results.

Power

As part of the business combination with AEC, the Company acquired two electricity contracts, one expiring in 2003 and the other in 2005. These contracts were originally entered into as part of an electricity cost management strategy. At December 31, 2002, the unrecognized loss on these contracts was $3 million.

B) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Company s operating and financial results. The Company has significant operations outside of Canada, which are subject to these foreign exchange risks.

The following forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2002:

	Amount Hedged (US$)	Average Exchange Rate (Cdn$/US$)	Unrecognized Gain/(Loss) (Cdn$)
2003	$372	0.716	$(72)
2004	88	0.715	(18)
Total	$460	0.716	$(90)

C) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company s interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrecognized gains on the outstanding financial instruments as at December 31, 2002 are:

Debt Instrument	Unrecognized Gain/(Loss) (Cdn$)
5.50% Medium Term Notes	$ 2
5.80% Medium Term Notes	11
7.50% Medium Term Notes	10
8.40% Medium Term Notes	13
8.75% Debenture	26
	$ 62

At December 31, 2002, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $26 million (2001 $5 million).

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

As at December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	$ 212	$ 212	$ 963	$ 963
Accounts receivable	2,052	2,052	623	623
Financial Liabilities				
Accounts payable, income taxes payable	$2,404	$2,404	$1,480	$1,480
Long-term debt	7,607	8,031	2,370	2,237

E) Credit Risk

The Company is exposed to credit related losses in the event of default by counterparties to financial instruments. The Company does not expect any counterparties to these agreements to fail to meet their obligations because of credit practices in place that limit transactions to counterparties of investment grade credit quality. A substantial portion of the Company s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Company has Board approved credit policies which govern the Company s credit portfolio.

All of the proceeds from the sale of the Company s crude oil production in Ecuador are received from one marketing company. Accounts receivable on these sales are supported by letters of credit issued by a major international financial institution. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

NOTE 20 SUPPLEMENTARY INFORMATION

Per Share Amounts

The following table summarizes the Common Shares used in calculating Net Earnings and Cash Flow per Common Share.

Years ended December 31	2002	2001	2000
Weighted Average Common Shares Outstanding Basic	417.8	255.6	252.8
Effect of Stock Options and Other Dilutive Securities	7.3	6.2	4.4
Weighted Average Common Shares Outstanding Diluted	425.1	261.8	257.2

The Net Earnings per Common Share calculations include the effect of the Distributions on Preferred Securities, net of tax, for the year of $3 million (2001 $4 million; 2000 $5 million).

Net Change in Non-Cash Working Capital from Continuing Operations

Years ended December 31	2002	2001	2000

Operating Activities			
Accounts receivable and accrued revenue	$ (386)	$ (12)	$ (372)
Inventories	(88)	29	(22)
Accounts payable and accrued liabilities	(5)	86	220
Income taxes payable	(846)	475	176
	$ (1,325)	$ 578	$ 2
Investing Activities			
Accounts payable and accrued liabilities	$ 293	$ 88	$ 42
Financing Activities			
Accounts payable and accrued liabilities	$ (5)	$ 1	$

Corporate Reorganization of Canadian Pacific Limited

On February 13, 2001, CPL announced a reorganization whereby its 85% interest in PanCanadian Petroleum Limited (predecessor to PanCanadian Energy Corporation) would be distributed to CPL common shareholders by a Plan of Arrangement. Following shareholder and court approvals, the Plan of Arrangement was implemented on October 1, 2001, and PanCanadian Petroleum Limited became a wholly owned subsidiary of the new public company, PanCanadian Energy Corporation. Effective January 1, 2002, these companies were amalgamated and continued under the name of PanCanadian Energy Corporation.

As part of the CPL reorganization, the Company paid a Special Dividend of $1,180 million ($4.60 per Common Share) on September 14, 2001. For the year ended December 31, 2001, the amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the regular quarterly dividend.

Related Party Transactions

In 2001, the Company paid $50 million relating to a previously contracted purchase price adjustment in respect of $200 million of capital losses acquired in 1997 from a subsidiary of CPL (the majority shareholder of the Company prior to the corporate reorganization as described previously). The purchase price adjustment, which was contingent on certain economic events, was recorded as a charge to retained earnings.

Prior to the previously described corporate reorganization of CPL, the Company purchased materials and utilized services from other companies with which it was affiliated. All such transactions were conducted on an arm s length basis and were not material in relation to the Company s overall activities.

NOTE 21 COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments over the next five years as follows:

	2003	2004	2005	2006	2007	Thereafter	Total
Pipeline Transportation	$ 461	$479	$410	$395	$387	$2,859	$4,991
Capital Commitments	791	317	62	38	6	61	1,275
Office Rental	54	52	51	51	44	237	489
Equipment Operating Leases	17	15	159	117	2	47	357
Other	40	1	56	51	29	352	529
Total	$1,363	$864	$738	$652	$468	$3,556	$7,641

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Future Dismantlement and Site Restoration Costs

The Company is responsible for the future dismantlement and site restoration related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company currently estimates the total amount of this future liability to be approximately $1,405 million, of which $494 million has been accrued based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Equipment Operating Leases

Between 1997 and 2001, the Company entered into lease arrangements for field equipment, natural gas storage equipment and aircraft. These leases were arranged through variable interest entities sponsored by various financial institutions. At the inception of the leases, the value of the equipment was $370 million. These variable interest entities are not consolidated in the Company s financial statements and the Company has accounted for these arrangements as operating leases in accordance with Canadian generally accepted accounting principles.

The leases are at normal commercial terms and expire between 2005 and 2008 with no renewal options. Future minimum lease payments related to these leases are included in the table above. The agreements for these leases contain various covenants including covenants regarding the Company s financial condition. Default under a lease, including violation of these covenants, could require the Company to purchase the leased equipment or aircraft for a specified amount, which approximates the lessor s original cost. As of December 31, 2002, the Company was in compliance with these covenants.

The Company has the option to purchase this leased equipment and aircraft in the year 2003 or to assist the variable interest entities in the sale of the assets at the end of the lease. The Company has provided a residual guarantee value for any deficiency if the equipment or aircraft are sold for less than the sale option amount. These amounts, if any, are not currently expected to have a material impact on the financial position or the results of operations of the Company.

The Financial Accounting Standards Board in the United States has issued FASB Interpretation 46 Consolidation of Variable Interest Entities effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that their primary beneficiary consolidate certain variable interest entities. As a result, the equipment operating leases will be consolidated under the new standard, as written.

NOTE 22 SUBSEQUENT EVENTS

Amalgamation with Alberta Energy Company Ltd.

On January 2, 2003, the Company announced that it had completed its vertical short-form amalgamation with its wholly owned subsidiary AEC effective January 1, 2003. EnCana Corporation is now the successor issuer in respect of AEC s previously issued debt securities, including the Preferred Securities, and will be responsible for all AEC s contractual obligations.

Sale of Interests in Cold Lake and Express Pipeline Systems

On January 2, 2003 and January 9, 2003 the Company announced that it had completed its previously announced sales of its interests in the Cold Lake and Express Pipeline Systems for estimated total proceeds of approximately $1.6 billion, including assumption of related long-term debt. Both sales are subject to closing and post-closing adjustments.

Sale of Interest in Syncrude Joint Venture

On February 3, 2003, the Company announced it had reached agreement with Canadian Oil Sands Limited to sell a 10 percent interest in the Syncrude Joint Venture for approximately $1.07 billion. The Company has also granted Canadian Oil Sands Limited an option, which expires December 31, 2003, to purchase its remaining 3.75% interest in Syncrude and an overriding royalty. If exercised, the option would generate approximately $417 million in additional proceeds.

NOTE 23 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which, in most respects, conform to accounting principles generally accepted in the United States (U.S. GAAP). The significant differences between Canadian and U.S. GAAP are described in this note.

Reconciliation of Net Earnings Under Canadian GAAP to U.S. GAAP

Years ended December 31		**2002**	**2001**	**2000**
Net Earnings from Continuing Operations Canadian GAAP		$1,225	$1,254	$1,000
Increase (Decrease) under U.S. GAAP				
Depreciation, depletion and amortization	*(Note A)*	19	5	8
Additional depletion	*(Note A)*		(145)	
Interest expense, net	*(Note B)*	(32)	(4)	(5)
Distributions on Preferred Securities of Subsidiary	*(Note B)*	20		
Change in fair value of financial instruments	*(Note C)*	(79)	141	(60)
Stock-based compensation	*(Note D)*	(5)	(15)	
Employee future benefits	*(Note E)*			1
Income taxes	*(Note G)*	37	(6)	(52)
Net Earnings from Continuing Operations U.S. GAAP		1,185	1,230	892
Net (Loss) Earnings from Discontinued Operations U.S. GAAP		(1)	33	21
Net Earnings U.S. GAAP		$1,184	$1,263	$ 913

Net Earnings per Common Share U.S. GAAP			
Basic	$ 2.83	$ 4.94	$ 3.61
Diluted	$ 2.79	$ 4.82	$ 3.55

Consolidated Statement of Earnings U.S. GAAP

Years ended December 31		2002	2001	2000
Revenues, Net of Royalties and Production Taxes		$10,011	$4,894	$4,366
Expenses				
Transportation and selling		574	172	148
Operating		1,438	693	620
Purchased product		3,448	1,144	1,019
Administrative	*(Notes D, E)*	192	98	67
Interest, net	*(Note B)*	451	49	74
Foreign exchange (gain) loss		(20)	20	37
Depreciation, depletion and amortization	*(Note A)*	2,134	992	764
Loss (gain) on derivatives	*(Note C)*	79	(108)	60
Loss (gain) on derivatives adoption of SFAS 133	*(Note C)*		(33)	
Gain on corporate disposition		(51)		
Net Earnings Before the Undernoted		1,766	1,867	1,577
Income tax expense	*(Note G)*	581	637	685
Net Earnings from Continuing Operations U.S. GAAP		1,185	1,230	892
Net (Loss) Earnings from Discontinued Operations U.S. GAAP		(1)	33	21
Net Earnings U.S. GAAP		$ 1,184	$1,263	$ 913
Net Earnings from Continuing Operations per Common Share U.S. GAAP				
Basic		$ 2.84	$ 4.81	$ 3.53
Diluted		$ 2.79	$ 4.70	$ 3.47
Net Earnings per Common Share U.S. GAAP				
Basic		$ 2.83	$ 4.94	$ 3.61
Diluted		$ 2.79	$ 4.82	$ 3.55

Condensed Consolidated Balance Sheet

As at December 31		2002		2001	
		As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets		$ 4,289	$ 4,289	$ 1,673	$ 1,674
Financial assets	*(Note C)*		286		217
Capital assets, net	*(Note A)*	23,770	23,589	8,162	7,962
Investments and other assets	*(Note B)*	377	388	237	241
Assets of discontinued operations				728	728
Goodwill		2,886	2,886		
		$31,322	$31,438	$10,800	$10,822

Liabilities and Shareholders Equity					
Current liabilities		$ 3,879	$ 3,879	$ 1,640	$ 1,643
Financial liabilities	*(Note C)*		412		257
Long-term debt	*(Note B)*	7,395	7,978	2,210	2,336
Deferred credits and other liabilities	*(Note B)*	585	592	325	312
Future income taxes	*(Note G)*	5,212	5,091	2,060	1,970
Liabilities of discontinued operations				586	586
Preferred securities of subsidiary	*(Note B)*	457			
		17,528	17,952	6,821	7,104
Preferred securities	*(Note B)*	126		126	
Share capital	*(Note D)*	8,732	8,752	196	211
Share options, net		133	133		
Paid in surplus		61	61	27	27
Retained earnings		4,684	4,503	3,630	3,486
Foreign currency translation adjustment	*(Note F)*	58			
Accumulated other comprehensive income	*(Note F)*		37		(6)
		13,794	13,486	3,979	3,718
		$31,322	$31,438	$10,800	$10,822

Statement of Other Comprehensive Income

Years ended December 31		2002	2001	2000
Net Earnings U.S. GAAP		$1,184	$1,263	$913
Adoption of SFAS 133, net of tax	*(Notes C, H)*		(79)	
Change in Fair Value of Financial Instruments	*(Note H)*	(11)	73	
Foreign Currency Translation Adjustment	*(Note F)*	58		
Other		(10)		
Other Comprehensive Income		$1,221	$1,257	$913

Condensed Consolidated Statement of Cash Flows U.S. GAAP

Years ended December 31	2002	2001	2000
Cash From Operating Activities			
Net earnings from continuing operations	$ 1,185	$ 1,230	$ 892
Depreciation, depletion and amortization	2,134	992	764
Future income taxes	630	140	522
Other	(173)	(107)	95
Cash flow from continuing operations	3,776	2,255	2,273
Cash flow from discontinued operations	42	47	25
Cash flow	3,818	2,302	2,298
Net change in other assets and liabilities	(22)	(63)	(74)
Net change in non-cash working capital from continuing operations	(1,325)	578	2
Net change in non-cash working capital from discontinued operations	97	(47)	(2)
	$ 2,568	$ 2,770	$ 2,224
Cash Used in Investing Activities	$(4,062)	$(1,697)	$(2,321)
Cash From Financing Activities	$ 750	$ (326)	$ 163

A) Full Cost Accounting

The full cost method of accounting for conventional oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production, site restoration and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that future revenues are undiscounted and administrative and interest expenses are deducted from revenues.

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

B) Preferred Securities

Under U.S. GAAP, preferred securities are classified as long-term debt and any distributions paid on these securities are treated as interest expense. Issue costs are capitalized and amortized to earnings over the term of the security. Under Canadian GAAP, preferred securities are classified as equity and any distributions paid, net of applicable income taxes, are recorded as a direct charge to retained earnings.

C) Derivative Instruments and Hedging

Prior to 2001, U.S. GAAP required fair value recognition in the financial statements with respect to forward foreign currency exchange contracts associated with anticipated future transactions that do not constitute firm commitments. Gains or losses arising from changes in the market value were immediately reflected in earnings. Under Canadian GAAP, the Company s forward foreign exchange contracts qualify as hedges for accounting purposes. Payments or receipts on these contracts are recognized in earnings concurrently with the hedged transaction and the fair values of the outstanding contracts are not reflected in the Consolidated Financial Statements.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards (SFAS) 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative s fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under SFAS 133.

The adoption of SFAS 133 at January 1, 2001 resulted in recognition of derivative assets with a fair value of $858 million, derivative liabilities with a fair value of $942 million, a $117 million ($79 million, net of tax) charge to other comprehensive income and a $33 million ($23 million, net of tax) increase to net earnings under U.S. GAAP.

As at December 31, 2002, it is estimated that over the following 12 months, $4 million ($2 million, net of tax) will be reclassified into earnings from other comprehensive income.

D) Stock-based Compensation

The Company accounts for its stock-based compensation using the intrinsic value method. Under Canadian GAAP, no compensation costs have been recognized in the financial statements for share options granted to employees and directors. Under Financial Accounting Standards Board (FASB) Interpretation No. 44 Accounting for Certain Transactions involving Stock Compensation , compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. For the effect of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 17.

As part of the Corporate reorganization, as described in Note 20, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by PanCanadian as described in Note 17. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

E) Employee Future Benefits

Prior to 2000, there was a difference between Canadian and U.S. GAAP in accounting for pension and other post-employment benefits.

Under U.S. GAAP, the discount rate used for computing the benefit obligation and the service and interest cost components of the net periodic pension expense is the rate at which the pension benefits could be currently settled. Prior to 2000, the Canadian GAAP discount rate was based on Management s best estimate of the future return on the plan assets.

Prior to 2000, the Company recognized the cost of providing other post-employment benefits as they were paid. U.S. GAAP requires these costs to be recognized on an accrual basis during the service period of the employees.

Effective January 1, 2000, the Company prospectively adopted the new Canadian accounting standard for Employee Future Benefits eliminating any significant differences between Canadian and U.S. GAAP in accounting for pension costs and other post-employment benefits.

F) Foreign Currency Translation Adjustments

U.S. GAAP requires gains or losses arising from the translation of self-sustaining foreign operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in Shareholders Equity.

G) Future Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

The future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

Years ended December 31	2002	2001	2000
Using Canadian GAAP			
Net earnings before income taxes	$1,863	$1,885	$1,633
Canadian Statutory Rate	42.3%	42.8%	44.7%
Expected Income Taxes	$ 788	$ 807	$ 730
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	232	113	104
Canadian resource allowance	(331)	(258)	(245)
Large corporations tax	35	16	16
Statutory rate differences	(57)	(19)	9
Effect of tax rate reductions	(33)	(81)	
Other	(16)	53	19
	618	631	633
U.S. GAAP Adjustments to Net Earnings Before Income Taxes	(97)	(18)	(56)
Expected Income Taxes	(41)	(8)	(25)
Depletion		3	4
FAS 109 Implementation Adjustments			74
Other	4	11	(1)
	(37)	6	52
Income Taxes U.S. GAAP	$ 581	$ 637	$ 685
Effective Tax Rate	32.9%	34.1%	43.4%

The net deferred income tax liability is comprised of:

As at December 31	2002	2001
Future Tax Assets		
Capital assets in excess of tax values	$4,708	$1,813
Timing of partnership items	809	292
Future Tax Liabilities		
Net operating losses carried forward	(320)	(135)
Other	(106)	
Net Future Income Tax Liability	$5,091	$1,970

H) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of SFAS133. At December 31, 2002, accumulated other comprehensive income, related to these items, was a loss of $11 million, net of tax.

I) Recent Accounting Pronouncements

During 2002, the following new or amended standards and guidelines were issued:

Asset Retirement Obligations

FASB issued SFAS No.143 Accounting for Asset Retirement Obligations , effective for years beginning after June 15, 2002. The standard requires legal obligations associated with the retirement of long-lived tangible assets be recognized at fair value. The Canadian Institute of Chartered Accountants issued an exposure draft, Asset Retirement Obligations , which would harmonize Canadian GAAP with SFAS No. 143 Accounting for Asset Retirement Obligations . The Canadian standard will be effective for fiscal years beginning on or after January 1, 2004. The Company is evaluating the impact of these new standards.

Hedging Relationships

The CICA issued Accounting Guideline 13   Hedging Relationships   which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. The effect of adopting the guideline on the Company s Consolidated Financial Statements has not been determined at this time.

Consolidation of Variable Interest Entities

FASB issued FASB Interpretation 46   Consolidation of Variable Interest Entities   effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that certain variable interest entities be consolidated by their primary beneficiary. At December 31, 2002, the Company has several operating leases that may be consolidated under the new standard. Refer to Note 21.

Stock-Based Compensation and Other Stock-Based Payments

In December 2002, the CICA issued an exposure draft for   Stock-Based Compensation and Other Stock-Based Payments . The new standard proposes to eliminate the option for an enterprise to disclose pro forma earnings and pro forma earnings per share as if the fair value based method of accounting had been applied. This would require the recognition of stock-based compensation expense for all stock-based compensation transactions.

Costs Associated with Exit or Disposal Activities

In June 2002, FASB issued SFAS 146   Accounting for Costs Associated with Exit or Disposal Activities . The standard requires that liabilities for exit or disposal activity costs be recognized and measured at fair value when the liability is incurred. This standard is effective for disposal activities initiated after December 31, 2002.

CONTROLS AND PROCEDURES

(a) ***Evaluation of disclosure controls and procedures***. As of a date within the 90-day period prior to the filing of this report, an evaluation of the effectiveness of the Company s disclosure controls and procedures (as such term is defined in Rules 13a-14(c) and 15d-14(c) of the United States Securities Exchange Act of 1934 (the Exchange Act)) was carried out by the Company s Chief Executive Officer (CEO) and Chief Financial Officer (CFO). Based on that evaluation, the CEO and CFO have concluded that as of such date the Company s disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in United States Securities and Exchange Commission rules and forms.

(b) ***Changes in Internal Controls***. Subsequent to the completion of their evaluation, there have been no significant changes in the Company s internal controls or in other factors that could significantly affect the internal controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

I

EXHIBITS

See the Exhibit Index to this Form 40-F.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking.

The Company undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Securities and Exchange Commission (the Commission) staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process.

The Company has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 27, 2003.

EnCana Corporation

By: /s/ John D. Watson

Name: John D. Watson
Title: Executive Vice-President & Chief Financial Officer

By: /s/ Thomas G. Hinton

Name: Thomas G. Hinton
Title: Treasurer

III

CERTIFICATIONS

I, Gwyn Morgan, certify that:

1. I have reviewed this annual report on Form 40-F of EnCana Corporation;

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

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

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

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

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

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

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

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

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

6. The registrant s other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 27, 2003

/s/ Gwyn Morgan

Gwyn Morgan
President & Chief Executive Officer
(Principal Executive Officer)

CERTIFICATIONS

I, John D. Watson, certify that:

1. I have reviewed this annual report on Form 40-F of EnCana Corporation;

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

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

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

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

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

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

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

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

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

6. The registrant s other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 27, 2003

/s/ John D. Watson

John D. Watson
Executive Vice-President & Chief
Financial Officer
(Principal Financial Officer)

V

EXHIBIT INDEX

Exhibit	Description
99.1	Consent of PricewaterhouseCoopers LLP
99.2	Consent of McDaniel & Associates Consultants Ltd.
99.3	Consent of Gilbert Laustsen Jung Associates Ltd.
99.4	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.5	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.6	Consent of Netherland, Sewell & Associates, Inc.
99.7	Consent of Ryder Scott Corporation
99.8	Financial Coverage on Long-Term Debt