ENCANA™

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.

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)
Extensions and discoveries	3.0	41.0	44.0	18.4	62.4	2.4	31.1	33.5	12.9	46.4
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
Extensions and discoveries	—	1.2	1.2	—	1.2	—	1.2	1.2	—	1.2
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 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] Calgary, Alberta	1992	President 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 .... Calgary, Alberta	President & Chief Executive Officer
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:

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