ENCANA CORP
Form 40-F
February 28, 2005

U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

(Check One)

o **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

or

þ **Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2004

Commission file number 1-15226

ENCANA CORPORATION

(Exact name of registrant as specified in its charter)

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

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

CT Corporation System, 111 8th Avenue, New York, NY 10011
(212) 894-8940
(Name, Address (Including Zip Code) and Telephone Number
(Including Area Code) of Agent For Service in the United States)

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

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

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

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

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

þ Annual Information Form þ Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report: 449,997,384

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

Yes o No þ

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

Yes þ No o

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the registrant s Registration Statements under the Securities Act of 1933: Form S-8 (File Nos. 333-13956 and 333-85598) and Form F-9 (File Nos. 333-113732 and 333-118737).

FORM 40-F

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F, beginning on the following page:

(a) Annual Information Form for the fiscal year ended December 31, 2004;

(b) Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2004; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2004 *(Note 20 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

ANNUAL INFORMATION FORM
February 25, 2005

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INTRODUCTORY INFORMATION

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

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

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

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

Unless otherwise specified, all dollar amounts are expressed in United States dollars and all references to dollars or $ are to United States dollars and all references to C$ are to Canadian dollars.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as anticipate , believe , expect , plan , intend or similar words suggesting future outcomes or statements regarding a outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: capital investment levels and the allocation thereof, drilling plans and the timing and location thereof, production capacity and levels and the timing of achieving such capacity and levels, pipeline capacity, the timing of pipeline construction, reserve estimates, the use of facilities related to the Hythe Gas Storage Facility and the timing thereof, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, plans for examining the Deep Panuke project, pending litigation, exploration plans, acquisition and disposition plans, including farmout plans, research and development plans, the timing and results of the environmental impact study in the Jonah area, the timing of acquisitions, the timing, completion and capacity of the Starks Storage facility, net cash flows, geographical expansion and plans for seismic acquisitions and surveys.

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

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

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

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the effective date of the estimation, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment. There are also differences in accepted practices for determining constant prices for purposes of evaluating bitumen reserves, as outlined under Narrative Description of the Business Reserves and Other Oil and Gas Information Reserve Quantities Information in this annual information form.

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

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

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

CORPORATE STRUCTURE

Name and Incorporation

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

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, 2004:

Subsidiaries & Partnerships	Percentage Owned[(1)]	Jurisdiction of Incorporation, Continuance or Formation
EnCana West Ltd.	100	Alberta
EnCana Oil & Gas Partnership	100	Alberta
EnCana USA Holdings	100	Delaware
3080763 Nova Scotia Company	100	Nova Scotia
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Marketing (USA) Inc.	100	Delaware
McMurry Oil Company[(2)]	100	Wyoming
Plaza Acquisition I Corp.[(2)]	100	Delaware
Tom Brown, Inc.[(2)]	100	Delaware
EnCana Midstream & Marketing (Holdings) Inc.	100	Canada
EnCana Midstream & Marketing	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Merged with EnCana Oil & Gas (USA) Inc. on January 1, 2005. EnCana Oil & Gas (USA) Inc. is the continuing entity.

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, 2004.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of North America s leading independent crude oil and natural gas exploration and production companies, based on landholdings and production at December 31, 2004. EnCana pursues growth from its portfolio of unconventional long-life resource plays situated in Canada and the United States. EnCana defines resource plays as large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have low geological and commercial development risk and low average decline rates. EnCana s disciplined pursuit of these unconventional assets enabled it to become North America s largest natural gas producer, based on production in the second half of 2004, and a leading developer of oilsands through in-situ recovery. The Corporation is also engaged in exploration and production activities internationally and has interests in midstream operations and assets, including natural gas storage facilities, NGLs processing facilities, power plants and pipelines.

EnCana operates under two main divisions: (i) Upstream; and (ii) Midstream & Marketing. The following describes the significant events in the last three years that have taken place in these divisions.

Upstream

The Upstream division manages EnCana s exploration for, and development and production of, natural gas, crude oil and NGLs and other related activities.

Following the Merger in 2002, the majority of EnCana s Upstream operations were located in Canada, the U.S., Ecuador and the U.K. central North Sea. From the time of the Merger through early 2004, EnCana focused on the development and expansion of its highest growth, highest return assets in these key areas. In 2004, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. In focusing its portfolio of assets, EnCana completed a number of significant acquisitions and dispositions during the past three years.

2004 Acquisitions:

In the first quarter of 2004, a subsidiary of EnCana completed the purchase, through two separate transactions, of additional interests in the U.K. central North Sea, for net cash consideration of approximately $131 million.

In May 2004, a subsidiary of EnCana completed the acquisition of Tom Brown, Inc. (Tom Brown) for total consideration of approximately $2.7 billion, including debt of approximately $406 million. Tom Brown was a resource play focused, natural gas exploration and production company headquartered in Denver, Colorado. The Tom Brown assets are located in the Piceance, Green River, Wind River, Paradox, East Texas, Permian and Western Canada Sedimentary basins.

In December 2004, a subsidiary of EnCana purchased natural gas assets in north Texas for approximately $251 million, subject to post-closing adjustments.

2004 Dispositions:

In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources (Petrovera), an Alberta partnership that produces heavy oil in western Canada, for net cash consideration of approximately $287 million.

In July 2004, a subsidiary of EnCana sold assets in New Mexico for approximately $228 million.

In August 2004, EnCana sold conventional natural gas properties in northeast Alberta for approximately $225 million, subject to post-closing adjustments.

In September 2004, the Corporation sold conventional oil and gas assets for approximately $388 million, subject to post-closing adjustments. This transaction included properties in east central and southern Alberta producing predominantly medium and heavy oil.

In December 2004, a subsidiary of EnCana closed the sale of all of its U.K. central North Sea assets for approximately $2.1 billion. These interests included a 43.2 percent interest in the Buzzard oil field, a 41.0 and 54.3 percent interest, respectively, in the Scott and Telford oil fields, other satellite discoveries, plus interests in exploration licences covering more than 740,000 net acres in the North Sea. As a result of this disposition, the U.K. Region is now treated as a discontinued operation for financial reporting purposes.

Concurrent with the announcement of the U.K. sale, EnCana designated its Ecuador and Gulf of Mexico assets as non-core (for planned future disposition) because these assets no longer fit with EnCana s North American resource play focus. The Ecuador assets include interests in five Oriente Basin blocks and a 36.3 percent interest in the

Oleoducto de Crudos Pesados (OCP) pipeline. The Ecuador Region is now treated as a discontinued operation for financial reporting purposes. The Gulf of Mexico assets include EnCana s interests in the Tahiti, Tonga, Sturgis, Sawtooth, Jack and St. Malo discoveries. EnCana has an average 40 percent interest in 239 exploration blocks covering approximately 1.4 million gross acres in the Gulf of Mexico.

In December 2004, EnCana announced its intention to sell additional mature western Canadian conventional oil and natural gas properties representing production of approximately 22,000 barrels of oil equivalent per day. EnCana expects these transactions to close in the second quarter of 2005.

In February 2005, EnCana Oil and Gas (USA) Inc. announced plans to sell three natural gas gathering and processing facilities in the U.S. Fort Lupton and Dragon Trail in Colorado, and Lisbon in Utah. The three plants have a total processing capacity of approximately 210 million cubic feet per day.

2003 Acquisitions:

In January 2003, EnCana acquired reserves and production in Ecuador from Vintage Petroleum, Inc. for net cash consideration of approximately $116 million.

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

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

In October 2003, a subsidiary of EnCana exchanged its non-operated interest in the Llano discovery in the Gulf of Mexico for an additional 14 percent interest in each of the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana.

2003 Dispositions:

In February 2003, EnCana sold a 10 percent interest in the Syncrude Joint Venture (Syncrude) for net cash consideration of approximately $690 million. In July 2003, EnCana sold its remaining 3.75 percent interest in Syncrude and an overriding royalty for net cash consideration of approximately $309 million. Both of these transactions are subject to post-closing adjustments. Syncrude operates a facility in northeast Alberta which produces crude oil from oilsands.

2002 Acquisitions:

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

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

Over the past three years, EnCana completed a number of other acquisitions and dispositions not listed above. The majority of these transactions were individually valued at less than $100 million.

Midstream & Marketing

EnCana s Midstream & Marketing division encompasses the Corporation s midstream operations and market optimization activities. EnCana s midstream activities are comprised of natural gas storage operations, NGLs processing and storage, power generation operations and pipelines. EnCana s marketing groups are focused on enhancing the sale of Upstream s proprietary production. Correspondingly, the marketing groups undertake market optimization activities, including third party purchases and sales of product, which provides operational flexibility for transportation commitments, product type, delivery points and customer diversification.

In focusing its portfolio of assets, the Midstream & Marketing division completed a number of project expansions as well as asset dispositions over the past three years.

2004 Projects:

In March 2004, a 10 billion cubic feet expansion was completed at the Wild Goose natural gas storage facility in northern California. The expansion increased the total working gas capacity to approximately 24 billion cubic feet.

In June 2004, following successful completion of its open season, Entrega Gas Pipeline Inc. (Entrega), an affiliate of EnCana Oil & Gas (USA) Inc., announced that it is proceeding with its proposed natural gas pipeline project. Entrega filed its certificate application with the U.S. Federal Energy Regulatory Commission (FERC) in September 2004 for construction of the pipeline from Colorado s Piceance Basin, through Wamsutter, Wyoming, to the Cheyenne natural gas trading hub in northeast Colorado. The pace of construction will be dependent upon FERC certification. If approved, the first segment of the pipeline to Wamsutter, Wyoming is expected to be on stream in late 2005, with an initial capacity of approximately 700 million cubic feet per day.

In November 2004, EnCana Midstream & Marketing, a wholly owned partnership of EnCana, signed a memorandum of understanding with The Premcor Refining Group Inc., an indirect wholly owned subsidiary of U.S. independent oil refiner Premcor Inc., to conduct a preliminary design and engineering study of the modifications necessary to upgrade Premcor s existing refinery at Lima, Ohio to process an estimated 200,000 barrels per day of blended EnCana heavy oil supplied under a proposed long-term sales contract. The memorandum contemplates the establishment of a 50-50 joint venture which would own and operate the upgraded refinery.

2004 Dispositions:

In December 2004, EnCana sold its 25 percent non-operated partnership interest in the Kingston CoGen Limited Partnership (Kingston CoGen) for net cash consideration of approximately $25 million, subject to post-closing adjustments. Kingston CoGen owns a 110 megawatt cogeneration plant in Kingston, Ontario.

In December 2004, EnCana disposed of its interest in the Alberta Ethane Gathering System joint venture for approximately $108 million, subject to post-closing adjustments.

2003 Projects:

In October 2003, the first phase of the Countess natural gas storage facility came online, adding 10 billion cubic feet of capacity. The facility is located east of Calgary. The completion of plant facilities at Countess increased capacity to approximately 30 billion cubic feet in 2004. Utilization of the full design capacity of 40 billion cubic feet is expected in 2005, upon approval to operate at increased pressures in the reservoir.

In October 2003, plans to develop a new natural gas storage facility at Starks, in southwest Louisiana, were announced by a subsidiary of EnCana. An open season for capacity was held in early 2004. In October 2004, an application was filed with the FERC requesting regulatory approval. Subject to regulatory approvals and a satisfactory second open season in February 2005, the facility is expected to be in service during the third quarter of 2006 with approximately 9 billion cubic feet of initial storage capacity. Full future capacity of the Starks facility is expected to be approximately 19 billion cubic feet.

2003 Dispositions:

In January 2003, EnCana completed the sale of its indirect 70 percent interest in the Cold Lake Pipeline System for approximately $270 million. Also in January 2003, EnCana completed the sale of its indirect 100 percent interest in the Express Pipeline System (Express) for approximately $778 million, which included the assumption of approximately $385 million in debt by the purchaser. EnCana retained crude oil transportation capacity on both pipelines through its existing long-term commercial contracts.

2002 Dispositions:

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

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NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana s onshore North America landholdings and key resource plays as of December 31, 2004.

UPSTREAM

The majority of EnCana s Upstream operations are located in Canada, the U.S. and Ecuador. International New Ventures Exploration is mainly focused on opportunities in Africa, Brazil, the Middle East and Greenland.

As at December 31, 2004, EnCana had net proved reserves of approximately 10.5 trillion cubic feet of natural gas and 501 million barrels of crude oil and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 67 percent of total net proved reserves. See Reserves and Other Oil and Gas Information in this annual information form.

Canada

EnCana has an industry-leading land position in western Canada of approximately 25 million gross acres (approximately 22 million net acres, of which approximately 14 million net acres are undeveloped). The mineral rights on approximately one third 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 Canadian Upstream operations are divided into two regions Canadian Plains and Canadian Foothills & Frontier.

Canadian Plains Region

The Canadian Plains Region encompasses EnCana s natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation s primary crude oil thermal recovery projects at Foster Creek and Christina Lake. The three key resource plays in the Canadian Plains Region are: (i) Shallow Gas in southern Alberta (2004 production of approximately 592 million cubic feet per day and 2003 production of approximately 507 million cubic feet per day); (ii) Coalbed Methane (CBM) developments in southern and central Alberta (2004 production of approximately 17 million cubic feet per day and 2003 production of approximately four million cubic feet per day); and (iii) Steam-Assisted Gravity Drainage (SAGD) operations at Foster Creek (2004 production of approximately 28,774 barrels per day and 2003 production of approximately 21,823 barrels per day).

EnCana s 2005 capital investment in core programs for natural gas projects in the Canadian Plains Region is budgeted to be approximately $1,085 million, with approximately $65 million directed to exploration and approximately $1,020 million to development. EnCana anticipates drilling approximately 4,098 gross natural gas wells (3,925 net wells) in this region in 2005. Capital investment in 2005 for crude oil projects is budgeted to be approximately $423 million, primarily directed towards development projects, including approximately $290 million for SAGD projects, and the drilling of approximately 358 gross oil wells (349 net wells).

The following table summarizes landholdings for the Canadian Plains Region as at December 31, 2004.

Landholdings	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Suffield	942	930	275	271	1,217	1,201	99%
Brooks	1,232	1,206	183	170	1,415	1,376	97%
Chinook	1,344	1,317	300	279	1,644	1,596	97%
Foster Creek	6	6	52	52	58	58	100%
Christina Lake	4	4	68	62	72	66	92%
Weyburn	73	64	460	449	533	513	96%
Other	2,873	2,452	5,890	5,502	8,763	7,954	91%
Canadian Plains Total	6,474	5,979	7,228	6,785	13,702	12,764	93%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d) 2004	2003	Crude Oil and NGLs (bbls/d) 2004	2003	Total Production (MMcfe/d) 2004	2003	Total Production (BOE/d) 2004	2003
Suffield	241	230	26,706	26,945	401	391	66,873	65,279
Brooks	474	434	15,542	15,295	568	526	94,542	87,628
Chinook	356	329	7,150	7,342	399	373	66,483	62,175
Foster Creek			28,774	21,823	173	131	28,774	21,823
Christina Lake			4,364	3,806	26	23	4,364	3,806
Weyburn			14,200	10,846	85	65	14,200	10,846
Other	203	188	30,184	44,171	384	453	64,017	75,504
Canadian Plains Total	1,274	1,181	126,920	130,228	2,036	1,962	339,253	327,061

The following table summarizes EnCana s interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	7,603	7,510	641	639	8,244	8,149
Brooks	9,622	9,006	699	573	10,321	9,579
Chinook	3,134	3,041	139	133	3,273	3,174
Foster Creek			36	36	36	36
Christina Lake			3	3	3	3
Weyburn			685	422	685	422
Other	1,888	1,499	1,322	937	3,210	2,436
Canadian Plains Total	22,247	21,056	3,525	2,743	25,772	23,799

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

Suffield

EnCana holds interests in the Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeast Alberta. Suffield is one of the core areas of the Shallow Gas resource play. EnCana also produces conventional heavy oil in the area. The Suffield area is largely made up of the Suffield Block, where operations are carried out by EnCana in cooperation with the Canadian military according to guidelines established under agreements with the Government of Canada.

Brooks

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons in the Brooks area of southern Alberta, located east of Calgary. This area is another core area of the Shallow Gas resource play and is largely comprised of EnCana fee title lands, covering a portion of the Palliser Block.

Chinook

The Chinook area is located immediately east of Calgary. The majority of the Corporation s lands in the area are fee title lands on the Palliser Block for which EnCana owns the mineral rights. In addition to operations in the Upper

Cretaceous shallow natural gas horizons, the Chinook area is the centre of EnCana s CBM resource play. The 1,100 section Horseshoe Canyon CBM development is located within the Chinook area. In 2004, EnCana drilled approximately 577 CBM wells on its project area on the Palliser Block, increasing production to approximately 30 million cubic feet per day at year-end. In 2005, EnCana plans to drill approximately 1,000 CBM wells, which is expected to increase CBM production to approximately 60 million cubic feet per day by year-end.

Foster Creek

EnCana has a 100 percent working interest in Foster Creek, one of the Corporation s two key crude oil resource plays. EnCana holds surface access and petroleum and natural gas rights for natural gas and oilsands exploration, development and transportation from areas within the Cold Lake Air Weapons Range (Primrose Block) which were granted by the Government of Canada. EnCana has acquired, and has certain rights to acquire, oilsands leases wherever deposits of bitumen are identified within the areas for which petroleum and natural gas lease rights are held. EnCana is currently operating a 100 percent owned thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology.

Pilot operations at Foster Creek commenced in 1998, and a 20,000 barrel per day commercial facility was started up in 2001. The first expansion, which increased commercial capacity to approximately 30,000 barrels per day, was completed in the third quarter of 2003. Net crude oil production in 2004 averaged approximately 28,800 barrels per day. An additional expansion has been approved and the engineering is underway. A total of 30,000 barrels per day of incremental production capacity is expected to be added in two stages with this development: 10,000 barrels per day of capacity is expected to be on stream in the fourth quarter of 2005, with an additional 20,000 barrels per day expected in the fourth quarter of 2006. EnCana anticipates reaching this expected output of 60,000 barrels per day in early 2007.

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

Christina Lake

EnCana has a 100 percent owned thermal crude oil recovery pilot project at Christina Lake which also uses SAGD technology. In 2004, EnCana added two well pairs and had total productive capacity of approximately 6,000 barrels per day at year-end.

Thermal Recovery Research and Development

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

One focus area is to reduce the reliance on steam in bitumen production. To this end, EnCana is piloting two technologies using solvents as part of the extraction process. The Solvent Aided Process (SAP) mixes a small amount of solvent with steam to enhance recovery. A second technology, the Vapex process, uses solvent in place of steam. After piloting SAP at Senlac, Saskatchewan in 2002, EnCana completed construction and commenced operation of a pilot operation at Christina Lake in 2004. The Vapex pilot at Foster Creek has been in operation since 2002. The first phase of the pilot is nearing completion, and there is additional research planned in the area for 2005.

Another focus area is artificial lift where EnCana is pursuing pump designs that are expected to enable the Corporation to optimize SAGD by operating at lower pressures, thereby realizing lower steam oil ratios and decreasing facility capital costs. EnCana now has more than 10 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to utilize this technology on new SAGD wells. Low pressure SAGD technology is being utilized in one well pair at Foster Creek, and EnCana plans to utilize this technology in up to 10 wells in 2005.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area with a carbon dioxide (CO_2) miscible flood project. In 2004, EnCana continued with its infill drilling program which began in 2003. This program ensures optimal coverage of areas currently within the enhanced oil recovery area. Four additional patterns, or well groupings, were completed in the CO_2 miscible flood development in 2004. As of December 31, 2004, there were 36 patterns on stream out of a planned total of 75 patterns.

Canadian Foothills & Frontier Region

The Canadian Foothills & Frontier Region includes EnCana s natural gas and crude oil exploration, development and production activities in northern Alberta and British Columbia. It also includes EnCana s exploration and development activities offshore the East Coast of Canada and in the Mackenzie Delta area of the Northwest Territories. There are three key resource plays in the Canadian Foothills & Frontier Region: (i) Greater Sierra; (ii) Cutbank Ridge; and (iii) Pelican Lake.

EnCana s 2005 capital investment in core programs for natural gas projects in the Canadian Foothills & Frontier Region is budgeted to be approximately $1,432 million, with approximately $150 million directed to exploration and approximately $1,282 million to development. EnCana plans to drill approximately 740 gross natural gas wells (688 net wells) and approximately 77 gross crude oil wells (77 net wells) in this region in 2005. Capital investment for crude oil projects is budgeted to be approximately $95 million, primarily directed towards development projects.

The following table summarizes landholdings for the Canadian Foothills & Frontier Region as at December 31, 2004.

Landholdings (thousands of acres)	Developed Acreage Gross	Net	Undeveloped Acreage Gross	Net	Total Acreage Gross	Net	Average Working Interest
Greater Sierra	464	397	2,780	2,424	3,244	2,821	87%
Cutbank Ridge	73	61	815	735	888	796	90%
Pelican Lake	83	83	135	135	218	218	100%
Sexsmith/ Hythe/Saddle Hills	288	194	242	178	530	372	70%
Cold Lake Air Weapons Range	386	365	473	469	859	834	97%
East Coast of Canada			5,861	3,558	5,861	3,558	61%
Mackenzie Delta			529	198	529	198	37%
Other	1,330	1,074	5,195	3,447	6,525	4,521	69%
Canadian Foothills & Frontier Total	2,624	2,174	16,030	11,144	18,654	13,318	71%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d) 2004	2003	Crude Oil and NGLs (bbls/d) 2004	2003	Total Production (MMcfe/d) 2004	2003	Total Production (BOE/d) 2004	2003
Greater Sierra	230	143	632	607	234	147	38,965	24,440
Cutbank Ridge	40	3			40	3	6,667	500
Pelican Lake	7	9	18,900	15,944	120	105	20,067	17,444
Sexsmith/ Hythe/Saddle Hills	110	114	2,785	2,990	127	132	21,118	21,990
Cold Lake Air Weapons Range	163	174			163	174	27,167	29,000
Other	286	323	5,149	6,665	317	362	52,815	60,499
	836	766	27,466	26,206	1,001	923	166,799	153,873

Canadian Foothills & Frontier Total

The following table summarizes EnCana s interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells	**Producing Gas Wells**		**Producing Oil Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Greater Sierra	559	516	2	2	561	518
Cutbank Ridge	69	63			69	63
Pelican Lake	15	15	514	514	529	529
Sexsmith/ Hythe/Saddle Hills	317	253	61	47	378	300
Cold Lake Air Weapons Range	608	583			608	583
Other	1,731	1,539	235	130	1,966	1,669
Canadian Foothills & Frontier Total	3,299	2,969	812	693	4,111	3,662

The following describes EnCana s major producing areas or activities in the Canadian Foothills & Frontier Region.

Greater Sierra

The Greater Sierra area of northeast British Columbia is one of EnCana s key natural gas resource plays. Production in the area has grown from essentially zero in 1998 to an average of approximately 230 million cubic feet per day in 2004. As at December 31, 2004, EnCana held an average 98 percent interest in 13 production facilities in the area that were capable of processing approximately 450 million cubic feet per day of natural gas. In 2004, EnCana completed the construction of the Ekwan pipeline which went into operation on April 1, 2004. The Ekwan pipeline transports natural gas from northeast British Columbia to Alberta. The pipeline extends approximately 80 kilometres and has a capacity of approximately 400 million cubic feet per day. December 2004 throughput for the pipeline was approximately 95 million cubic feet per day.

Cutbank Ridge

Cutbank Ridge is a key natural gas resource play located in the Canadian Rocky Mountain foothills, approximately 50 kilometres southwest of Dawson Creek, British Columbia. The majority of the Corporation s lands in this area were purchased in 2003. In 2004, EnCana drilled approximately 50 net natural gas wells at Cutbank Ridge and increased production to approximately 47 million cubic feet per day of natural gas by year-end. In 2005, EnCana plans to drill approximately 100 net natural gas wells at Cutbank Ridge.

Pelican Lake

Pelican Lake is another of EnCana s key resource plays producing crude oil in north-central Alberta. In 2004, EnCana continued to expand the waterflood program at Pelican Lake, which has increased the recovery of crude oil in the area. EnCana also holds a 38 percent non-operated interest in a 110-kilometre, 20-inch diameter crude oil pipeline which connects the Pelican Lake area to a major pipeline that transports crude oil from northern Alberta to crude oil markets.

Sexsmith/ Hythe/Saddle Hills

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

Cold Lake Air Weapons Range

EnCana produces natural gas from the Cold Lake Air Weapons Range (formerly referred to as the Primrose Block) located in northeast Alberta. The majority of EnCana s natural gas production in the area is processed through 100 percent controlled and operated compression facilities. In 2004, production in the area was impacted by the September 2003 Alberta Energy and Utilities Board decision to shut-in natural gas production that may put at risk the recovery of bitumen resources in the area. The decision resulted in a decrease in annualized natural gas production in the area of approximately eight million cubic feet per day. In January 2005, the Government of Alberta reached an agreement with natural gas producers which partially compensates the producers for this shut-in production.

East Coast of Canada

Offshore Nova Scotia on the East Coast of Canada, EnCana has a 100 percent working interest in the Deep Panuke natural gas discovery. EnCana is in the process of examining the potential economic viability of the Deep Panuke project, and this is expected to continue in 2005.

In 2004, EnCana participated in the drilling of the Weymouth and Crimson deep water exploration wells offshore Nova Scotia. Both wells were unsuccessful.

EnCana also has other interests in exploration lands located offshore Nova Scotia and Newfoundland and Labrador.

Mackenzie Delta

EnCana drilled one exploration well in the Mackenzie Delta region of Canada s Northwest Territories in 2004. EnCana plans to drill one additional well in the area in 2005, as well as conduct further testing of the well drilled in 2004.

United States

EnCana s operations in the U.S. Rockies area are focused on exploiting deep, tight, long-life, unconventional natural gas formations primarily in the Jonah sweet natural gas field located in the Green River Basin of southwest Wyoming, and in the Piceance Basin of northwest Colorado (which includes the Mamm Creek natural gas field). The acquisition of Tom Brown in May 2004 expanded EnCana s operations within the Green River and Piceance Basins. EnCana s U.S. operations also include interests in the East Texas and Fort Worth Basins in Texas, the Gulf of Mexico and Alaska, as well as natural gas gathering and processing assets. The majority of the production in the U.S. is from resource plays. The key resource plays are: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth.

EnCana s 2005 capital investment in core programs for natural gas projects in the U.S. is budgeted to be approximately $1,482 million, with approximately $77 million directed to exploration and approximately $1,405 million to development, and includes the drilling of approximately 923 gross natural gas wells (789 net wells). There are no budgeted amounts for capital investment in crude oil projects.

The following table summarizes EnCana s landholdings in the United States as at December 31, 2004.

Landholdings	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Jonah	12	10	48	47	60	57	95%
Piceance	241	216	860	796	1,101	1,012	92%
East Texas	68	40	167	142	235	182	77%
Fort Worth	36	33	127	127	163	160	98%
Gulf of Mexico			1,371	557	1,371	557	41%
Alaska			1,337	531	1,337	531	40%
Other	351	208	2,615	2,140	2,966	2,348	79%
United States Total	708	507	6,525	4,340	7,233	4,847	67%

The following table sets forth daily average production figures for the periods indicated.

Production	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)		Total Production (BOE/d)	
(annual average)	2004	2003	2004	2003	2004	2003	2004	2003
Jonah	389	374	3,294	3,348	409	394	68,127	65,681
Piceance	261	151	3,074	2,473	279	166	46,574	27,640
East Texas	50		167		51		8,500	
Fort Worth	27	7	233	136	28	8	4,733	1,303
Other	142	56	6,037	3,504	179	77	29,704	12,837
United States Total	869	588	12,805	9,461	946	645	157,638	107,461

The following table summarizes EnCana s interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells	**Producing Gas Wells**		**Producing Oil Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Jonah	386	343			386	343
Piceance	2,486	2,065			2,486	2,065
East Texas	458	263			458	263
Fort Worth	399	366			399	366
Other	2,062	1,224	30	12	2,092	1,236
United States Total	5,791	4,261	30	12	5,821	4,273

The following describes EnCana s major producing areas or activities in the United States.

Jonah

EnCana produces natural gas and associated NGLs from the Jonah field, located in southwest Wyoming. The Jonah key resource play represents EnCana s initial entry into the U.S. Rockies region. Since arriving in 2000, EnCana has approximately tripled both reserves and production mainly through a combination of infill drilling and advanced hydraulic fracturing techniques. This approach has enabled the Corporation to access the reserves of natural gas in the Lance formation that makes up the Jonah play. These stacked sands exist at depths between 8,000 and 11,500 feet. The U.S. Bureau of Land Management is working on an Environmental Impact Statement covering future development in the area. The study is expected to be complete by mid-2005. EnCana expects that the results of the study will be positive for the Corporation, and will allow for increased production growth at Jonah.

Piceance

The Piceance Basin in northwest Colorado is one of EnCana s key natural gas resource plays. This basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. EnCana entered the basin in 2001 with its acquisition of the Mamm Creek field. The May 2004 acquisition of Tom Brown included properties and natural gas production in the basin. As of December 31, 2004, EnCana had accumulated over one million net acres in the basin and had production of approximately 285 million cubic feet per day.

East Texas

EnCana produces natural gas in the East Texas Basin. The East Texas properties were acquired as part of the Tom Brown acquisition in 2004, and the basin is one of EnCana s newest key resource plays. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2004, EnCana drilled approximately 50 net wells in the basin.

Fort Worth

EnCana produces natural gas and associated NGLs in the Fort Worth Basin in north Texas. Fort Worth is one of EnCana s key resource plays, and the Corporation has assembled a significant land position in the Barnett Shale play in this basin. The Corporation entered the area in 2003 with the acquisition of Savannah Energy Inc. (Savannah). EnCana is applying horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. The Corporation s December 2004 purchase of natural gas assets in north Texas included properties located in the Fort Worth Basin.

Gulf of Mexico

In the summer of 2004, an EnCana subsidiary, EnCana Gulf of Mexico LLC, participated in two exploration and appraisal activities in the Gulf of Mexico. A production test was completed on the two primary zones in the Tahiti well, in which EnCana holds a 25 percent non-operated interest. The well produced at a restricted rate of 15,000 barrels per day. Rate and pressure analysis indicate that the well may be capable of sustained flow of as much as 30,000 barrels of oil per day. In addition, EnCana participated in the deep water Jack exploration well which encountered approximately 350 feet of net pay. EnCana has a 25 percent non-operated interest in the well. In total, EnCana subsidiaries have participated in six discoveries in the Gulf of Mexico since 2002.

In late 2004, the Gulf of Mexico assets were deemed to be non-core to EnCana. The Corporation plans to dispose of these assets in 2005.

Alaska

In late 2004, EnCana s assets in Alaska were deemed to be non-core by the Corporation. EnCana plans to dispose of these assets in 2005.

Gathering & Processing Facilities

EnCana owns and operates various gas gathering and NGLs processing facilities. Near Rifle, Colorado, EnCana s gathering facilities have a capacity of approximately 360 million cubic feet per day and include over 645 kilometres of pipelines. Near Fort Lupton, Colorado, the gathering facilities include field compression and over 1,000 kilometres of pipelines. The Fort Lupton processing plant has a capacity of approximately 90 million cubic feet per day. The Corporation s gathering facilities in Rangely, Colorado include field compression and over 1,600 kilometres of pipelines. The Dragon Trail processing plant near Rangely has a capacity of approximately 60 million cubic feet per day. The Lisbon plant in Moab, Utah was acquired as part of the Tom Brown acquisition. The Lisbon plant is a sophisticated cryogenic natural gas processing plant with a capacity of approximately 60 million cubic feet per day.

In February 2005, the Corporation announced its intention to sell the Fort Lupton, Dragon Trail and Lisbon plants and the associated gas gathering facilities.

International New Ventures Exploration

EnCana invests a small portion (approximately two percent) of its capital in high potential exploration beyond its core geographic areas, primarily in Africa, Brazil, the Middle East and Greenland.

Central and West Africa

EnCana s onshore exploration operations in Chad are based out of the Corporation s office in N Djamena. EnCana has a 50 percent working interest in Permit H comprising approximately 108 million gross acres (approximately 54 million net acres). EnCana acquired seismic data and completed the drilling of four exploration wells in 2004. In 2005, the Corporation expects to acquire seismic data and anticipates drilling three to five exploration and/or appraisal wells.

In July 2004, EnCana assigned its entire interest in the offshore Keta Block in Ghana to its partner. The assignment has been submitted to the Government of Ghana and EnCana is awaiting final approval of its exit from Ghana.

Brazil

In 2004, EnCana entered into a Technology Cooperation Agreement for heavy oil activities with Petrobras, the Brazilian national oil company. This agreement is part of a larger cooperation including joint participation with Petrobras in Agência Nacional do Petróleo (ANP) Bid Round 6, in which EnCana acquired an average working interest ranging from 30 to 40 percent in seven Petrobras-operated blocks. This acquisition increased the Corporation s landholdings by approximately 1.1 million gross acres (approximately 402,000 net acres). In 2005, activity on these offshore blocks is expected to be limited to seismic acquisition.

In ANP Bid Round 6, EnCana also acquired a 25 percent non-operated interest in offshore Block 101, increasing its land position by approximately 177,000 gross acres (approximately 44,000 net acres). In addition to these newly acquired blocks, EnCana has a 67 percent working interest in Block BM-C-7 comprising approximately 161,000 gross acres (approximately 108,000 net acres) offshore Brazil. In 2004, the Corporation drilled one exploration well and one appraisal well on this block. Evaluation of the results is expected to continue in 2005.

Middle East

In October 2004, EnCana reached an agreement with the Government of Qatar to enter the second phase of its exploration production sharing agreement on Block 2. This block encompasses most of the onshore lands in the State of Qatar. EnCana s 100 percent working interest in the landholdings on the block total approximately 2.2 million acres. Plans for 2005 include expected seismic activity and pursuing the planned farmout of a portion of EnCana s working interest.

In 2004, the Corporation farmed out a portion of its working interest in Block 47 in the Republic of Yemen. The Corporation has a 36.75 percent working interest in Block 47 (approximately 1.9 million gross acres and approximately 691,000 net acres). EnCana drilled one unsuccessful exploration well on the block in 2004.

EnCana has a 100 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman, which cover approximately 9.6 million acres. EnCana conducted seismic surveys in 2004 and expects to drill one well in 2005. In 2005, EnCana also plans to pursue the farmout of a portion of its interest in Oman.

EnCana has a 50 percent non-operated working interest in Block 5 in the Kingdom of Bahrain. Block 5 is comprised of approximately 97,000 gross acres (approximately 48,000 net acres). During 2004, seismic data was acquired and one exploration well was drilled and abandoned. EnCana exited the block in early 2005.

Greenland

EnCana acquired one exploration licence (Lady Franklin) in the 2004 Offshore West Greenland Bid Round. This licence was signed in January 2005. EnCana also has an 87.5 percent working interest in the Atammik block, offshore west Greenland, consisting of approximately 985,000 gross acres (approximately 862,000 net acres). EnCana conducted seismic activities in 2004. In 2005, EnCana expects to conduct additional seismic activity and pursue the farmout of a portion of its working interest in Greenland.

Ecuador

In late 2004, the Ecuador Region was deemed to be non-core to EnCana. The Corporation plans to dispose of its Ecuadorian operations in 2005. As a result, the Ecuador Region is now treated as a discontinued operation for financial reporting purposes.

An indirect, wholly owned subsidiary of EnCana owns a concession in the Oriente Basin, known as the Tarapoa Block. The Corporation has a 100 percent working interest in this concession, which is operated under a participation contract which has a primary term through to August 1, 2015. EnCana also has a 40 percent non-operated economic interest in Block 15 in the Oriente Basin. This concession is operated under a participation contract which has primary terms through to July 2012 for base area production and July 2019 for production resulting from additional exploration. In addition, EnCana has a majority operating interest in Blocks 14, 17 and Shiripuno, also in the Oriente Basin. The production contracts for Blocks 14 and 17 expire in July 2012 and December 2018, respectively.

At December 31, 2004, EnCana held an average 64 percent working and economic interest in approximately 1.4 million gross acres (approximately 894,000 net acres, of which approximately 795,000 net acres are undeveloped) in Ecuador. At December 31, 2004, 211 gross crude oil wells (151 net wells) were producing. EnCana s contractual entitlement to net crude oil production in 2004 was 76,872 barrels per day (51,089 barrels per day in 2003).

EnCana s interests in Ecuador also include an indirect 36.3 percent equity interest in the OCP pipeline. OCP is a 500-kilometre pipeline with a capacity of approximately 450,000 barrels per day that runs from the crude oil producing area of Ecuador to the Pacific Coast. In 2004, shipments on OCP totalled approximately 170,599 barrels per day. Pursuant to the terms of the agreement with the Government of Ecuador, OCP will be transferred to the Government of Ecuador, without cost, after a 20-year operating period. EnCana has a 15-year shipping commitment on OCP of approximately 108,000 barrels per day. EnCana s shipments on OCP in 2004 averaged approximately 72,636 barrels per day.

MIDSTREAM & MARKETING

Midstream

EnCana s midstream activities are primarily comprised of natural gas storage operations, NGLs processing and storage, power generation operations and pipelines. EnCana s 2005 capital investment in core programs in its midstream operations is budgeted to be approximately $342 million.

Natural Gas Storage

Based upon overall storage capacity, EnCana is the largest independent (non-utility) natural gas storage operator in North America with facilities in Alberta, California and Oklahoma. EnCana also leases natural gas storage capacity from other storage operators located in the U.S. Gulf Coast and mid-continent regions. At December 31, 2004, EnCana had owned and operated storage capacity of approximately 163 billion cubic feet, as well as leased storage capacity of approximately 15 billion cubic feet.

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

AECO HUB™

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

Suffield Gas Storage Facility

Located on the Suffield Block in southeast Alberta, this facility was the first and is the most significant in the AECO HUBtm portfolio. It 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

The Hythe Gas Storage Facility in northwest Alberta has approximately 10 billion cubic feet of working natural gas capacity, approximately 200 million cubic feet per day of withdrawal capability, and approximately 150 million cubic feet per day of injection capability. The facility is connected to both the Alberta pipeline system of TransCanada Corporation and the Alliance Pipeline system. Commencing April 1, 2004, the compression and pipeline facilities related to the Hythe Gas Storage Facility were temporarily removed from gas storage service and utilized by the Upstream division to facilitate additional production from Cutbank Ridge. This facility is expected to return to gas storage service effective April 1, 2005.

Countess Gas Storage Facility

In October 2002, EnCana announced plans to develop a new natural gas storage facility in southeast Alberta that is expected to store up to 40 billion cubic feet of natural gas. The Countess Gas Storage Facility consists of two depleted underground reservoirs located about 85 kilometres east of Calgary. The first 10 billion cubic feet of new storage capacity came online in 2003, with free-flow injection through the summer and plant facilities completion in October. The completed facilities increased 2004 storage capacity to approximately 30 billion cubic feet, maximum withdrawal capability to approximately 850 million cubic feet per day and maximum injection capability to approximately 800 million cubic feet per day. The full 40 billion cubic feet of storage capacity and additional withdrawal capability are expected to be utilized in 2005, upon approval to operate at increased pressures in the reservoir.

Wild Goose Gas Storage Facility

The Wild Goose Gas Storage Facility, located north of Sacramento, California was California s first independent natural gas storage facility. In July 2002, Wild Goose was granted permission by the California Public Utilities Commission to approximately double the storage size and approximately triple the withdrawal capacity of the facility. Completion of the initial phase expansion was completed in March 2004, bringing the total working gas capacity to approximately 24 billion cubic feet. The expansion also increased maximum withdrawal capability to approximately 480 million cubic feet per day and expanded maximum injection capability to approximately 450 million cubic feet per day.

Salt Plains Gas Storage Facility

The Salt Plains Gas Storage Facility, located in northern Oklahoma, has a capacity of 15 billion cubic feet, a maximum withdrawal capability of approximately 200 million cubic feet per day and a maximum injection capability of approximately 150 million cubic feet per day.

Starks Project

In October 2003, Starks Gas Storage L.L.C., an indirect wholly owned subsidiary of EnCana, announced plans to develop a high-deliverability storage facility in southwest Louisiana. Subject to regulatory approvals and a satisfactory second open season, the facility is expected to be in-service during the third quarter of 2006 with approximately 9 billion cubic feet of initial storage capacity, 350 million cubic feet of injection capacity and 400 million cubic feet of withdrawal capacity. Full future capacity of the Starks facility is expected to be approximately 19 billion cubic feet.

Leased Storage Capacity

EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, has entered into contracts to lease storage capacity in the U.S. Gulf Coast and mid-continent regions. Total leased capacity at December 31, 2004 was approximately 15 billion cubic feet. Contracts for approximately 7 billion cubic feet of this capacity expire at the end of March 2005, with the remaining contract terms ranging from 15 months to 12 years.

Natural Gas Liquids

EnCana holds interests in four NGLs extraction plants that straddle two major natural gas pipelines at Empress, Alberta plus storage and fractionation assets in Saskatchewan, eastern Canada and the U.S.

At Empress, the rights to extract NGLs from natural gas transported through transmission pipelines are acquired from the shippers of the natural gas. As at December 31, 2004, EnCana s share of the combined processing capacity was approximately 2.1 billion cubic feet per day.

Ethane recovered at Empress is sold as a specification product to petrochemical companies for consumption within the Province of Alberta. The remaining liquids components are transported as a mixed stream by pipeline to a plant at Sarnia, Ontario in which EnCana holds an approximate 10.4 percent interest. The mixed stream is fractionated at Sarnia into marketable products: propane, butane and pentanes plus. These are sold to distributors, refiners and petrochemical manufacturers in Canada and the U.S. under contracts, the terms of which are typically one year or less.

Other significant NGLs midstream assets include: (i) a 50 percent interest in a pipeline that delivers NGLs from Empress to storage facilities and the Enbridge pipeline at Kerrobert, Saskatchewan; (ii) interests in a NGLs storage facility and depropanizer at Superior, Wisconsin; and (iii) a 49 percent interest in a propane and butane storage facility at Marysville, Michigan.

Power

EnCana is a large consumer of electricity in Alberta and uses a portfolio of physical assets, short to medium term purchases and sales and spot market purchases to manage the cost of electricity for its Upstream and Midstream divisions in Alberta s deregulated market. The physical assets include two 106 megawatt power plants in southern Alberta and the 80 megawatt Foster Creek cogeneration facility (part of EnCana s Foster Creek SAGD operation). The Cavalier Power Station, located approximately 54 kilometres east of Calgary, is 100 percent owned and operated by EnCana. The Balzac Power Station, in which EnCana holds a 50 percent non-operated interest, is also located near Calgary. EnCana s electricity requirements in Alberta are approximately 300 megawatts and its generation capacity is approximately 239 megawatts. The Corporation disposed of its 25 percent non-operated partnership interest in the 110 megawatt Kingston CoGen plant in December 2004.

Pipelines

In 2004, Entrega, an affiliate of EnCana Oil & Gas (USA) Inc., announced that it is proceeding with its proposed natural gas pipeline project. Once complete, the pipeline is expected to transport natural gas out of Colorado s Piceance Basin, through Wamsutter, Wyoming, to the Cheyenne natural gas trading hub in northeast Colorado. Upon receipt of FERC certification, the first segment of the pipeline through Wamsutter is expected to be on stream in late 2005, with an initial capacity of approximately 700 million cubic feet per day.

EnCana holds a 36 percent equity investment in the Trasandino Pipeline system which carries crude oil from Argentina s Neuquen Basin to refineries in Chile. The pipeline is 420 kilometres in length and has a design capacity of approximately 113,000 barrels per day. Shipments on the Trasandino system in 2004 averaged approximately 57,000 barrels per day (approximately 104,000 barrels per day in 2003). In 2004, as a result of ongoing volume reductions, EnCana reduced the carrying value of its investment in Trasandino by approximately $35 million.

Marketing

EnCana s marketing groups are focused on enhancing the sales of the Corporation s proprietary production. Correspondingly, the marketing groups conduct market optimization activities that include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

Natural Gas Marketing

In 2004, approximately 89 percent of EnCana s produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 11 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

To mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to produced natural gas. Details of these transactions are found in Note 17 to EnCana s audited consolidated financial statements for the year ended December 31, 2004.

In 2004, EnCana sold approximately 51 percent of its produced natural gas (after royalties and mineral taxes) at fixed prices, approximately 4 percent at AECO Index based pricing, approximately 36 percent at NYMEX based pricing and approximately 9 percent at other prices. As of December 31, 2004, for 2005 EnCana has arranged for the sale of approximately 26 percent of its natural gas at fixed prices, approximately 26 percent of its natural gas at insured floor prices, approximately 12 percent exposed to AECO Index based prices, approximately 29 percent exposed to NYMEX based prices and approximately 7 percent at other prices.

In addition to sales of its proprietary production, EnCana purchases and sells natural gas for the purpose of optimizing the profitability of its midstream assets and the netback price of the Corporation s proprietary production. In 2004, EnCana s sales of purchased natural gas amounted to approximately 895 million cubic feet per day (approximately 903 million cubic feet per day in 2003).

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (140,911 barrels per day in 2004 and 138,784 barrels per day in 2003). Crude oil sales are normally executed under spot and monthly evergreen contracts with delivery to major pipeline hubs, such as Edmonton and Hardisty, in Alberta, with EnCana arranging the intermediate transportation on the feeder pipeline systems. Sales are also made on a delivered basis using trunk pipeline systems, such as Enbridge, for sales to U.S. refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2004, EnCana acted as exclusive agent for Canadian Oil Sands Limited (COS) and marketed COS Syncrude volumes of 85,157 barrels per day (64,863 barrels per day in 2003). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government s Department of Energy (73,852 barrels per day in 2004 and 69,264 barrels per day in 2003). This agency agreement ends in the second quarter of 2007.

In Ecuador, EnCana s crude oil volumes are sold FOB at the marine loading facility at Balao, Esmeraldas Province, Ecuador. A total of 77,845 barrels per day was marketed in 2004 (45,561 barrels per day in 2003). Until

September 2003, Ecuador production was transported from the Ecuador Oriente region to Balao via the SOTE Pipeline. EnCana began shipping on the OCP Pipeline in September 2003, and the pipeline was fully commissioned in November 2003. EnCana s production in Ecuador consists of a high viscosity crude oil with characteristics well-suited to refineries on the U.S. West and Gulf Coasts.

To mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to crude oil. Details of these transactions are found in Note 17 to EnCana s audited consolidated financial statements for the year ended December 31, 2004.

NGLs Marketing

EnCana s production of NGLs in western Canada is marketed through Kinetic Resources (LPG), an Alberta partnership in which EnCana has an indirect 75 percent interest, and Kinetic Resources (U.S.A.), a Michigan partnership in which EnCana has an indirect 75 percent interest (collectively, Kinetic). In 2004, Kinetic continued to market a portion of EnCana s western Canada NGLs primarily to eastern Canada and the U.S. Kinetic also markets NGLs on behalf of other parties. An indirect 100 percent owned affiliate of EnCana also directly markets certain U.S.-produced NGLs volumes to U.S.-based customers.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana s crude oil and natural gas reserves as of December 31, 2004. EnCana s Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd. EnCana s U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton. EnCana s Ecuadorian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. 2004 was the third consecutive year in which all of EnCana s reserves were independently evaluated.

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

Any references to NGLs in this section include condensate.

As at December 31, 2004, both the U.K. and Ecuador Regions are classified as discontinued operations for financial reporting purposes.

Reserve Quantities Information

EnCana s natural gas reserves increased in 2004 from exploration and development drilling and acquisitions. The Corporation s crude oil and NGLs reserves decreased in 2004 primarily as a result of the divestiture of non-core properties and a negative revision in Canadian bitumen reserves as a result of anomalously lower year-end bitumen prices, as further discussed below. EnCana s reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions. Reserve acquisitions were approximately equal to reserve dispositions in 2003. The Corporation s reserves increased in 2002 predominantly from the Merger with AEC, and also partly due to extensions and discoveries. The 2002 increase was partially offset by downward revisions of reserve quantities.

On December 31, 2004, being the effective date for the Corporation s reserves evaluations, field prices for bitumen were much lower than the average for 2004 due to market conditions. The application of U.S. standards for the determination of constant prices as at that date resulted in the removal of the Corporation s Foster Creek bitumen reserves from the proved category, encompassing a negative revision of approximately 363 million barrels. Canadian securities regulators, in recognition that the bitumen market is not yet mature and that there are no published reference prices for bitumen, have accepted an approach in determining the constant price for bitumen based on using the published price for WTI and historical averages for the adjustments that create the difference in price between WTI and bitumen. Under the accepted Canadian methodology, there would not have been any negative revisions of the Corporation s proved bitumen reserves.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69. The end of year numbers for 2004 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2003 and 2002 represent estimates derived from the reports of the independent qualified reserves evaluators who evaluated EnCana s reserves as of December 31, 2003 and December 31, 2002.

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

	Natural Gas (billions of cubic feet)					Crude Oil and Natural Gas Liquids (millions of barrels)					
	Canada	United States	United Kingdom	Other	Total	Canada	United States	Ecuador	United Kingdom	Other	Total
2002											
Beginning of year	3,504	236	7		3,747	286.6	19.6		21.6		327.8
Purchase of AEC reserves in place	2,686	944			3,630	233.7	6.5	168.4			408.6
Revisions and improved recovery	(1,140)	731	7		(402)	(15.5)	4.6	(33.5)	(9.1)		(53.5)
Extensions and discoveries	726	319	10		1,055	96.9	3.3	31.1	89.2		220.5
Purchase of reserves in place	30	530			560	4.9	9.9				14.8
Sale of reserves in place	(129)	(73)			(202)	(18.2)	(0.7)				(18.9)
Production	(604)	(114)	(4)		(722)	(46.5)	(2.3)	(10.2)	(4.1)		(63.1)
End of year	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
Developed	4,139	1,446	9		5,594	299.2	21.9	104.6	8.3		434.0
Undeveloped	934	1,127	11		2,072	242.7	19.0	51.2	89.3		402.2
Total	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
2003											
Beginning of year	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
Revisions and improved recovery	73	1	3		77	32.3	0.5	0.4	23.5		56.7
Extensions and discoveries	867	706		90	1,663	110.9	7.4	11.9		0.9	131.1
Purchase of reserves in place	9	152	8		169	1.3	0.9	17.3	7.1		26.6
Sale of reserves in place	(60)	(88)		(90)	(238)	(0.2)	(4.7)	(5.1)		(0.9)	(10.9)
Production	(706)	(215)	(5)		(926)	(56.8)	(3.4)	(18.6)	(3.7)		(82.5)

End of year	5,256	3,129	26	8,411	629.4	41.6	161.7	124.5	957.2
Developed	3,984	1,833	13	5,830	306.1	26.3	115.0	16.7	464.1
Undeveloped	1,272	1,296	13	2,581	323.3	15.3	46.7	107.8	493.1
Total	5,256	3,129	26	8,411	629.4	41.6	161.7	124.5	957.2
2004									
Beginning of year	5,256	3,129	26	8,411	629.4	41.6	161.7	124.5	957.2
Revisions and improved recovery	67	(252)		(185)	31.1 [3]	0.2	(11.5)		19.8
Extensions and discoveries	1,422	1,009		2,431	93.6 [3]	47.6	21.2		162.4
Purchase of reserves in place	65	1,150	10	1,225	29.4	11.7		10.1	51.2
Sale of reserves in place	(215)	(82)	(25)	(322)	(97.3)	(5.4)		(128.4)	(231.1)
Production	(771)	(318)	(11)	(1,100)	(56.6)	(4.7)	(28.1)	(6.2)	(95.6)
End of year before bitumen revisions	5,824	4,636		10,460	629.6	91.0	143.3		863.9
Revisions due to bitumen price					(362.7) [4]				(362.7)
End of year	5,824	4,636 [5]		10,460	266.9	91.0 [5]	143.3 [6]		501.2
Developed	4,406	2,496		6,902	210.2	31.5	122.5		364.2
Undeveloped	1,418	2,140		3,558	56.7	59.5	20.8		137.0
Total	5,824	4,636		10,460	266.9	91.0	143.3		501.2

Notes:

(1) Definitions:

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

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

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

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

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

(3) An aggregate of approximately of 75.8 million barrels of proved reserves in the Foster Creek area are subject to the revisions due to bitumen price, including approximately 5.4 million barrels under revisions and improved recovery and approximately 70.4 million barrels under extensions and discoveries.

(4) Removal of the Corporation s Foster Creek proved bitumen reserves as described under Reserve Quantities Information .

(5) Includes approximately 14 billion cubic feet of natural gas and approximately 38.8 million barrels of crude oil and NGLs reserves attributable to the Corporation s Gulf of Mexico assets, which EnCana plans to dispose of in 2005.

(6) The Corporation plans to dispose of its Ecuadorian operations in 2005. Accordingly, Ecuador is treated as a discontinued operation for financial reporting purposes.

Other Disclosures About Oil and Gas Activities

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

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

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

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

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

	Canada			**United States**			**Ecuador**		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
					($ millions)				
Future cash inflows	37,791	35,126	29,890	27,063	17,472	9,398	3,317	3,533	3,368
Future production costs	7,760	9,630	5,873	2,462	1,456	2,090	1,136	738	635
Future development costs	4,906	4,388	2,813	3,406	1,433	1,270	220	249	273
Undiscounted pre-tax cash flows	25,125	21,108	21,204	21,195	14,583	6,038	1,961	2,546	2,460
Future income taxes	6,279	5,874	6,353	7,021	4,960	1,504	342	536	585
Future net cash flows	18,846	15,234	14,851	14,174	9,623	4,534	1,619	2,010	1,875
Less discount of net cash flows using a 10% rate	6,668	5,219	6,018	6,686	4,735	2,383	417	643	617
Discounted future net cash flows	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258

	United Kingdom			Total		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
				($ millions)		
Future cash inflows		3,483	2,565	68,171	59,614	45,221
Future production costs		961	397	11,358	12,785	8,995
Future development costs		1,008	836	8,532	7,078	5,192
Undiscounted pre-tax cash flows		1,514	1,332	48,281	39,751	31,034
Future income taxes		456	483	13,642	11,826	8,925
Future net cash flows		1,058	849	34,639	27,925	22,109
Less discount of net cash flows using a 10% rate		493	438	13,771	11,090	9,456
Discounted future net cash flows		565	411	20,868	16,835	12,653

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

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Balance, beginning of year	10,015	8,833	3,060	4,888	2,151	300	1,367	1,258	
Changes resulting from:									
Sales of oil and gas produced during the period	(3,965)	(3,429)	(2,092)	(1,474)	(889)	(329)	(264)	(258)	(157)
Discoveries and extensions, net of related costs	3,562	1,272	1,293	2,436	1,381	293	236	126	330
Purchases of proved AEC reserves in place			6,810			1,044			1,830
Purchases of proved reserves in place	531	26	93	2,786	340	613		93	
Sales of proved reserves in place	(1,579)	(95)	(371)	(271)	(108)	(72)		(54)	
Net change in prices and production costs	2,264	242	3,358	143	2,751	194	(294)	(47)	
Revisions to quantity estimates	546	416	(1,345)	(542)	4	667	(125)	4	(354)
Accretion of discount	1,349	1,636	455	725	304	56	176	182	
Previously estimated development costs incurred net of change in future development costs	57	340	101	22	534	54	15	89	
Other	32	470	(67)	(49)	157	(51)	(29)	(27)	
Net change in income taxes	(634)	304	(2,462)	(1,176)	(1,737)	(618)	120	1	(391)
Balance, end of year	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258

	United Kingdom			Total		
	2004	2003	2002	2004	2003	2002
	($ millions)					
Balance, beginning of year	565	411	140	16,835	12,653	3,500
Changes resulting from:						
	(78)	(83)	(81)	(5,781)	(4,659)	(2,659)

Sales of oil and gas produced during the period						
Discoveries and extensions, net of related costs			594	6,234	2,779	2,510
Purchases of proved AEC reserves in place						9,684
Purchases of proved reserves in place	77	57		3,394	516	706
Sales of proved reserves in place	(899)			(2,749)	(257)	(443)
Net change in prices and production costs		(119)	(1)	2,113	2,827	3,551
Revisions to quantity estimates		157	(53)	(121)	581	(1,085)
Accretion of discount	82	91	14	2,332	2,213	525
Previously estimated development costs incurred net of change in future development costs		108	3	94	1,071	158
Other		(38)	(8)	(46)	562	(126)
Net change in income taxes	253	(19)	(197)	(1,437)	(1,451)	(3,668)
Balance, end of year		565	411	20,868	16,835	12,653

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	4,787	4,189	2,630	1,861	1,091	406	451	367	224
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	822	760	538	387	202	77	187	109	67
Depreciation, depletion and amortization	1,752	1,511	871	487	297	206	263	159	79
Operating income (loss)	2,213	1,918	1,221	987	592	123	1	99	78
Income taxes	841	218	456	375	219	47	5	17	28
Results of operations	1,372	1,700	765	612	373	76	(4)	82	50

	United Kingdom			Other			Total		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	117	102	92				7,216	5,749	3,352
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	39	19	11	4	20	29	1,439	1,110	722
Depreciation, depletion and amortization	118	74	39	25	83	35	2,645	2,124	1,230
Operating income (loss)	(40)	9	42	(29)	(103)	(64)	3,132	2,515	1,400
Income taxes	(15)	17	17		(4)		1,206	467	548
Results of operations	(25)	(8)	25	(29)	(99)	(64)	1,926	2,048	852

Capitalized Costs

Canada			United States			Ecuador		
2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**

	($ millions)								
Proved oil and gas properties	22,455	18,549	12,504	7,552	3,485	2,769	1,784	1,372	1,000
Unproved oil and gas properties	1,855	1,981	1,573	728	501	415	45	70	60
Total capital cost	24,310	20,530	14,077	8,280	3,986	3,184	1,829	1,442	1,060
Accumulated DD&A	9,770	7,498	4,770	1,046	516	262	534	188	73
Net capitalized costs	14,540	13,032	9,307	7,234	3,470	2,922	1,295	1,254	987

	United Kingdom			**Other**			**Total**		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
	($ millions)								
Proved oil and gas properties		675	445				31,791	24,081	16,718
Unproved oil and gas properties		77	3	425	317	226	3,053	2,946	2,277
Total capital cost		752	448	425	317	226	34,844	27,027	18,995
Accumulated DD&A		230	136	247	206	98	11,597	8,638	5,339
Net capitalized costs		522	312	178	111	128	23,247	18,389	13,656

Costs Incurred

	Canada			United States			Ecuador		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
					($ millions)				
Acquisitions									
AEC unproved reserves			1,496			444			221
other unproved reserves	42	47	12	954	21	202		80	
AEC proved reserves			3,540			1,024			686
other proved reserves	204	207	78	2,051	115	457		59	
Total acquisitions	246	254	5,126	3,005	136	2,127		139	907
Exploration	555	846	403	164	187	226	28	20	35
Development	2,669	2,131	902	1,103	651	282	213	111	133
Total costs incurred	3,470	3,231	6,431	4,272	974	2,635	241	270	1,075

	United Kingdom			Other			Total		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
					($ millions)				
Acquisitions									
AEC unproved reserves									2,161
other unproved reserves		16					996	164	214
AEC proved reserves									5,250
other proved reserves	130	95					2,385	476	535
Total acquisitions	130	111					3,381	640	8,160
Exploration	22	30	16	79	78	118	848	1,161	798
Development	364	96	66				4,349	2,989	1,383
Total costs incurred	516	237	82	79	78	118	8,578	4,790	10,341

Daily Sales Volumes, Royalty Rates and Per-Unit Results

Daily Sales Volumes

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

	Daily Sales Volumes 2004				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal/(injection)	(6)	(26)			
Canada Sales[(1)]	2,099	2,080	2,138	2,177	2,000
United States	869	1,007	958	824	684
Total Produced Gas	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and medium oil	56,215	52,725	52,824	64,448	54,940
Heavy oil	84,164	79,336	89,682	79,899	87,729
Natural gas liquids					
Canada	13,452	13,452	12,804	13,588	13,971
United States	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids[(2)]	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations ***(MMcfe/d)***	3,966	4,044	4,114	4,025	3,679
Total Continuing Operations ***(BOE/d)***	661,084	673,970	685,673	670,854	613,210
Discontinued Operations:					
Ecuador					
Production[(3)]	76,872	76,235	76,567	78,376	76,320
Over/(under) lifting	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales *(bbls/d)*	77,993	77,876	74,846	78,303	80,982

United Kingdom *(BOE/d)*	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations *(MMcfe/d)*	594	551	570	630	623
Total Discontinued Operations *(BOE/d)*	98,966	91,803	95,068	105,031	103,737
Total *(MMcfe/d)*	4,560	4,595	4,684	4,655	4,302
Total *(BOE/d)*	760,050	765,773	780,741	775,885	716,947

Notes:

(1) Net dispositions total approximately 42 MMcf/day for the full year 2004.

(2) Net dispositions total approximately 15,500 bbls/day for the full year 2004.

(3) 2004 includes approximately 31,000 bbls/day related to Block 15.

	Daily Sales Volumes	2003			
	Year	Q4	Q3	Q2	Q1
SALES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal/(injection)	30				120
Canada Sales	1,965	2,008	1,914	1,899	2,042
United States	588	654	604	558	534
Total Produced Gas	2,553	2,662	2,518	2,457	2,576
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and medium oil	54,459	56,585	54,597	52,733	53,890
Heavy oil	87,867	95,059	94,985	82,001	79,171
Natural gas liquids					
Canada	14,278	13,348	13,758	14,740	15,291
United States	9,291	9,479	9,530	10,194	7,943
Total Oil and Natural Gas Liquids	165,895	174,471	172,870	159,668	156,295
Total Continuing Operations ***(MMcfe/d)***	3,548	3,709	3,555	3,415	3,514
Total Continuing Operations ***(BOE/d)***	591,395	618,138	592,537	569,168	585,628
Discontinued Operations:					
Ecuador					
Production	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline[1]	(3,213)		(4,919)	(2,039)	(5,941)
Over/(under) lifting	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales *(bbls/d)*	46,521	77,352	39,807	37,221	31,273
United Kingdom *(BOE/d)*	12,295	18,400	6,979	11,019	12,777
Syncrude *(bbls/d)*	7,629		3,399	7,316	20,070
	399	574	301	333	385

Total Discontinued Operations *(MMcfe/d)*					
Total Discontinued Operations *(BOE/d)*	66,445	95,752	50,185	55,556	64,120
Total *(MMcfe/d)*	3,947	4,283	3,856	3,748	3,899
Total *(BOE/d)*	657,840	713,890	642,722	624,724	649,748

Note:

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

	Daily Sales Volumes 2002				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	1,717	1,943	1,959	1,980	975
Inventory withdrawal/(injection)	(6)	117	(51)	(90)	
Canada Sales	1,711	2,060	1,908	1,890	975
United States	337	516	423	345	58
Total Produced Gas	2,048	2,576	2,331	2,235	1,033
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and medium oil	58,328	55,265	58,321	58,885	60,903
Heavy oil	58,890	77,090	70,795	67,558	19,350
Natural gas liquids					
Canada	13,852	15,987	13,985	14,168	11,212
United States	6,407	10,016	5,901	6,368	3,274
Total Oil and Natural Gas Liquids	137,477	158,358	149,002	146,979	94,739
Total Continuing Operations ***(MMcfe/d)***	2,873	3,526	3,225	3,117	1,601
Total Continuing Operations ***(BOE/d)***	478,810	587,691	537,502	519,479	266,906
Discontinued Operations:					
Ecuador					
Production	27,625	34,856	37,447	37,702	
Over/(under) lifting	2,115	1,044	2,316	5,088	
Ecuador Sales *(bbls/d)*	29,740	35,900	39,763	42,790	
United Kingdom *(BOE/d)*	12,195	9,120	11,038	13,299	14,722
Syncrude *(bbls/d)*	23,540	33,918	35,585	24,152	
Total Discontinued Operations ***(MMcfe/d)***	393	474	518	481	88

Total Discontinued Operations *(BOE/d)*	65,475	78,938	86,386	80,241	14,722
Total *(MMcfe/d)*	3,266	4,000	3,743	3,598	1,689
Total *(BOE/d)*	544,285	666,629	623,888	599,720	281,628

Average Royalty Rates

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

	2004					2003					2002				
	Year	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	12.5	12.0	12.2	12.7	13.3	12.9	12.2	12.9	14.2	12.4	10.7	13.3	10.4	11.8	2.7
United States	19.6	19.8	18.3	21.1	19.3	20.0	19.5	20.2	20.1	20.5	21.1	21.1	23.1	19.4	19.4
Crude Oil															
Canada and United States	9.0	8.7	8.8	11.6	9.4	10.3	9.7	9.0	10.7	11.8	11.0	10.8	11.7	11.6	9.5
Natural Gas Liquids															
Canada	15.7	16.5	18.5	13.1	14.8	17.5	14.7	16.6	18.0	20.2	13.8	16.4	13.8	15.6	6.9
United States	18.7	21.4	13.6	20.7	19.2	17.6	17.5	17.0	17.3	18.5	10.8	13.3	12.0	10.5	
Total Upstream	13.7	13.8	13.2	14.1	13.7	13.8	13.2	13.4	14.5	13.9	12.3	14.1	12.7	12.8	5.7
Discontinued Operations:															
Crude Oil Ecuador	27.1	27.8	26.5	26.5	27.4	25.6	25.4	25.7	24.9	26.9	28.4	28.1	28.5	28.5	

Per-Unit Results

The following tables summarize net per-unit results for EnCana on a quarterly basis for the periods indicated. The results exclude the impact of realized financial hedging.

	Per-Unit Results 2004				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Continuing Operations:					

Produced Gas Canada ($/Mcf)					
Price	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	0.08	0.10	0.09	0.07	0.08
Transportation and selling	0.39	0.39	0.37	0.35	0.44
Operating	0.52	0.55	0.50	0.49	0.56
Netback	4.35	4.82	4.14	4.29	4.13
Produced Gas United States ($/Mcf)					
Price	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	0.65	0.69	0.57	0.80	0.51
Transportation and selling	0.31	0.27	0.26	0.34	0.39
Operating	0.37	0.41	0.36	0.37	0.33
Netback	4.46	5.16	4.17	4.21	4.16
Produced Gas Total North America ($/Mcf)					
Price	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	0.25	0.29	0.24	0.27	0.19
Transportation and selling	0.36	0.35	0.33	0.35	0.43
Operating	0.48	0.50	0.46	0.46	0.50
Netback	4.38	4.94	4.15	4.26	4.14
Natural Gas Liquids Canada ($/bbl)					
Price	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes					
Transportation and selling	0.41	0.47	0.45	0.35	0.35
Netback	31.02	36.26	33.01	28.13	26.92

	Per-Unit Results 2004				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids United States ($/bbl)					
Price	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	3.82	3.94	4.05	3.93	3.09
Transportation and selling					
Netback	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids Total North America ($/bbl)					
Price	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	1.84	2.00	2.14	1.90	1.23
Transportation and selling	0.21	0.23	0.21	0.18	0.21
Netback	31.31	35.52	32.50	28.55	28.02
Crude Oil Light and Medium North America ($/bbl)					
Price	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	0.96	1.38	0.85	0.79	0.86
Transportation and selling	1.01	1.04	1.08	0.76	1.19
Operating	5.85	6.41	6.49	4.84	5.87
Netback	26.85	30.74	28.98	26.04	22.00
Crude Oil Heavy North America ($/bbl)					
Price	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	1.09	(0.57)	1.63	1.50	1.69
Operating	5.32	6.27	4.79	4.82	5.44
Netback	16.96	15.63	21.54	16.04	14.29
Crude Oil Total North America ($/bbl)					
Price	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	0.41	0.57	0.34	0.35	0.37
Transportation and selling	1.06	0.07	1.42	1.17	1.50
Operating	5.53	6.33	5.42	4.83	5.61
Netback	20.92	21.66	24.31	20.50	17.25
Total Liquids Canada ($/bbl)					
Price	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	0.37	0.52	0.31	0.32	0.34
Transportation and selling	1.00	0.11	1.35	1.10	1.40
Operating	5.05	5.75	4.98	4.42	5.11

Netback	21.79	22.98	24.99	21.15	18.10
Total Liquids North America ($/bbl)					
Price	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	0.63	0.82	0.63	0.59	0.49
Transportation and selling	0.93	0.10	1.23	1.02	1.32
Operating	4.67	5.24	4.55	4.09	4.82
Netback	22.54	24.04	25.62	21.73	18.76

	Per-Unit Results 2004				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Total North America ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating	0.55	0.59	0.53	0.52	0.58
Netback	4.23	4.72	4.18	4.11	3.87
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	2.13	2.73	2.62	1.84	1.37
Transportation and selling	2.12	1.57	2.36	1.92	2.63
Operating	4.39	5.02	4.35	4.14	4.04
Netback	20.04	20.65	24.14	19.88	15.78
Crude Oil United Kingdom ($/bbl)					
Price	36.92	46.19	40.88	34.68	31.11
Production and mineral taxes					
Transportation and selling	2.06	2.17	2.44	1.85	1.94
Operating	6.75	5.00	9.98	7.84	3.86
Netback	28.11	39.02	28.46	24.99	25.31

	Per-Unit Results 2003				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	0.07	0.10	0.08	0.08	0.02
Transportation and selling	0.38	0.44	0.40	0.35	0.33
Operating	0.48	0.45	0.50	0.47	0.48
Netback	3.94	3.42	3.63	4.02	4.70
Produced Gas United States ($/Mcf)					
Price	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	0.47	0.42	0.46	0.46	0.57
Transportation and selling	0.40	0.51	0.39	0.36	0.32
Operating	0.28	0.29	0.33	0.31	0.20
Netback	3.73	3.49	3.64	3.61	4.23
Produced Gas Total North America ($/Mcf)					
Price	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	0.16	0.18	0.17	0.17	0.14
Transportation and selling	0.39	0.46	0.40	0.35	0.33
Operating	0.43	0.41	0.46	0.43	0.42
Netback	3.89	3.44	3.63	3.93	4.60
Natural Gas Liquids Canada ($/bbl)					
Price	24.26	25.13	23.52	21.02	27.31
Production and mineral taxes					
Transportation and selling	0.17	0.13	0.58		
Netback	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids United States ($/bbl)					
Price	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	2.03	2.69	2.64	1.21	1.55
Transportation and selling					
Netback	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids Total North America ($/bbl)					
Price	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	0.80	1.12	1.08	0.50	0.53
Transportation and selling	0.10	0.08	0.35		

Netback	24.43	24.57	22.90	22.00	28.45
Crude Oil Light and Medium North America ($/bbl)					
Price	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	1.42	1.33	0.71	1.73	1.95
Operating	6.00	6.28	5.93	6.07	5.68
Netback	18.90	17.19	19.02	18.92	20.63
Crude Oil Heavy North America ($/bbl)					
Price	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	1.24	1.54	0.58	1.37	1.56
Operating	5.67	4.95	5.93	6.18	5.70
Netback	12.73	11.85	11.91	12.18	15.38

	Per-Unit Results	2003			
	Year	Q4	Q3	Q2	Q1
Crude Oil Total North America ($/bbl)					
Price	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	1.31	1.46	0.63	1.51	1.72
Operating	5.80	5.45	5.93	6.13	5.70
Netback	15.09	13.84	14.50	14.82	17.49
Total Liquids Canada ($/bbl)					
Price	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	1.21	1.36	0.62	1.36	1.54
Operating	5.27	5.01	5.43	5.53	5.11
Netback	15.91	14.74	15.22	15.43	18.52
Total Liquids North America ($/bbl)					
Price	22.72	21.69	20.81	22.88	25.88
Production and mineral taxes	0.19	0.43	(0.55)	0.49	0.44
Transportation and selling	1.14	1.28	0.59	1.28	1.46
Operating	4.97	4.74	5.13	5.18	4.85
Netback	16.42	15.24	15.64	15.93	19.13
Total North America ($/Mcfe)					
Price	4.57	4.24	4.31	4.58	5.17
Production and mineral taxes	0.13	0.15	0.10	0.14	0.12
Transportation and selling	0.33	0.39	0.31	0.31	0.31
Operating	0.54	0.52	0.58	0.55	0.53
Netback	3.57	3.18	3.32	3.58	4.21
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	1.47	1.06	0.45	1.11	4.27
Transportation and selling	2.56	2.81	2.36	2.41	2.35
Operating	4.84	4.62	4.33	5.63	5.09
Netback	15.34	15.08	14.99	13.16	19.15
Crude Oil United Kingdom ($/bbl)					
Price	28.11	27.05	27.92	27.17	30.61

Production and mineral taxes					
Transportation and selling	1.97	1.70	1.98	1.86	2.45
Operating	5.09	6.23	6.55	4.69	2.92
Netback	21.05	19.12	19.39	20.62	25.24

	Per-Unit Results 2002				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price(1)	2.86	3.60	2.29	2.93	2.25
Production and mineral taxes	0.08	0.07	0.04	0.10	0.14
Transportation and selling	0.24	0.30	0.21	0.21	0.22
Operating	0.41	0.44	0.42	0.40	0.31
Netback	2.13	2.79	1.62	2.22	1.58
Produced Gas United States ($/Mcf)					
Price(1)	2.96	3.48	2.78	2.51	2.36
Production and mineral taxes	0.27	0.34	0.22	0.23	0.29
Transportation and selling	0.47	0.46	0.76	0.23	
Operating	0.28	0.23	0.28	0.31	0.60
Netback	1.94	2.45	1.52	1.74	1.47
Produced Gas Total North America ($/Mcf)					
Price(1)	2.87	3.58	2.37	2.86	2.26
Production and mineral taxes	0.11	0.12	0.08	0.12	0.15
Transportation and selling	0.28	0.33	0.31	0.22	0.21
Operating	0.39	0.40	0.39	0.39	0.32
Netback	2.09	2.73	1.59	2.13	1.58
Natural Gas Liquids Canada ($/bbl)					
Price	17.55	21.75	17.61	17.41	11.56
Production and mineral taxes					
Transportation and selling					
Netback	17.55	21.75	17.61	17.41	11.56
Natural Gas Liquids United States ($/bbl)					
Price	23.75	25.14	25.64	23.57	16.31
Production and mineral taxes	1.02	0.94	1.32	1.37	
Transportation and selling					
Netback	22.73	24.20	24.32	22.20	16.31
Natural Gas Liquids Total North America ($/bbl)					
Price	19.52	23.06	19.99	19.32	12.64
Production and mineral taxes	0.32	0.36	0.39	0.42	
Transportation and selling					

Netback	19.20	22.70	19.60	18.90	12.64
Crude Oil Light and Medium North America ($/bbl)					
Price	22.31	24.39	24.09	23.37	17.60
Production and mineral taxes	0.65	0.48	0.51	0.14	1.44
Transportation and selling	0.94	1.22	1.04	0.62	0.87
Operating	4.80	5.15	4.72	5.29	4.08
Netback	15.92	17.54	17.82	17.32	11.21

Note:

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

	Per-Unit Results 2002				
	Year	Q4	Q3	Q2	Q1
Crude Oil Heavy North America ($/bbl)					
Price	17.88	17.38	19.67	17.76	13.62
Production and mineral taxes	0.22	0.54	0.03	0.04	0.32
Transportation and selling	0.71	0.93	0.81	0.48	0.21
Operating	4.58	4.12	4.96	4.39	5.73
Netback	12.37	11.79	13.87	12.85	7.36
Crude Oil Total North America ($/bbl)					
Price	20.08	20.31	21.67	20.37	16.64
Production and mineral taxes	0.43	0.51	0.25	0.08	1.17
Transportation and selling	0.82	1.05	0.92	0.55	0.71
Operating	4.69	4.55	4.85	4.81	4.48
Netback	14.14	14.20	15.65	14.93	10.28
Total Liquids Canada ($/bbl)					
Price	19.82	20.46	21.27	20.07	16.01
Production and mineral taxes	0.39	0.46	0.22	0.08	1.03
Transportation and selling	0.73	0.94	0.83	0.49	0.63
Operating	4.19	4.06	4.38	4.32	3.93
Netback	14.51	15.00	15.84	15.18	10.42
Total Liquids North America ($/bbl)					
Price	20.00	20.76	21.44	20.22	16.03
Production and mineral taxes	0.42	0.49	0.27	0.13	0.99
Transportation and selling	0.70	0.88	0.79	0.47	0.60
Operating	4.00	3.80	4.20	4.14	3.79
Netback	14.88	15.59	16.18	15.48	10.65
Total North America ($/Mcfe)					
Price	3.01	3.55	2.71	3.01	2.41
Production and mineral taxes	0.10	0.11	0.07	0.10	0.15
Transportation and selling	0.23	0.28	0.26	0.18	0.17
Operating	0.47	0.46	0.48	0.47	0.43
Netback	2.21	2.70	1.90	2.26	1.66
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	22.57	24.02	22.82	21.11	

Production and mineral taxes	1.24	1.57	1.49	0.72	
Transportation and selling	2.00	1.99	2.47	1.56	
Operating	4.86	5.35	4.12	5.13	
Netback	14.47	15.11	14.74	13.70	
Crude Oil United Kingdom ($/bbl)					
Price	24.76	25.73	27.07	25.92	21.18
Production and mineral taxes					
Transportation and selling	1.69	1.53	1.92	1.62	1.65
Operating	3.28	7.07	3.65	2.01	1.78
Netback	19.79	17.13	21.50	22.29	17.75

The following tables show the impact of Upstream realized financial hedging on EnCana s per-unit results.

	2004				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.22)	(0.37)	(0.15)	(0.25)	(0.08)
Liquids ($/bbl)	(7.08)	(8.24)	(8.75)	(6.53)	(4.79)
Total ($/Mcfe)	(0.46)	(0.61)	(0.48)	(0.47)	(0.27)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(9.66)	(14.60)	(10.31)	(7.13)	(6.69)
United Kingdom Oil ($/bbl) (1)	(7.62)	(6.34)	(11.75)	(7.01)	(5.72)

	2003				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Liquids ($/bbl)	(3.41)	(3.29)	(2.76)	(2.08)	(5.64)
Total ($/Mcfe)	(0.23)	(0.04)	(0.18)	(0.28)	(0.44)
Discontinued Operations:					
Ecuador Oil ($/bbl)					
United Kingdom Oil ($/bbl)					

	2002				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	0.09	0.02	0.26	(0.06)	0.20
Liquids ($/bbl)	(0.64)	(0.73)	(0.56)	(0.72)	(0.53)
Total ($/Mcfe)	0.03	(0.02)	0.16	(0.08)	0.10
Discontinued Operations:					
Ecuador Oil ($/bbl)	(0.01)			(0.03)	

United Kingdom Oil ($/bbl)	(0.06)	(0.19)

Note:

(1) Excludes hedges unwound as a result of the U.K. disposition.

Drilling Activity

The following tables summarize EnCana s gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled

	Gas		**Oil**		**Dry & Abandoned**		**Total Working Interest**		**Royalty**	**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Gross**	**Net**
Continuing Operations:											
2004:											
Canada	566	534	48	47	9	6	623	587	51	674	587
United States	19	16	2				21	16		21	16
Other			3	2	5	2	8	4		8	4
Total	585	550	53	49	14	8	652	607	51	703	607
2003:											
Canada	532	511	51	31	35	28	618	570	153	771	570
United States	40	35	7	2	4	2	51	39		51	39
Other	1				3	1	4	1		4	1
Total	573	546	58	33	42	31	673	610	153	826	610
2002:											
Canada	423	382	84	72	44	37	551	491	190	741	491
United States	12	12	2	1	3	1	17	14		17	14
Other					4	2	4	2		4	2
Total	435	394	86	73	51	40	572	507	190	762	507
Discontinued Operations:											
Ecuador 2004			6	3			6	3		6	3
Ecuador 2003			3	2			3	2		3	2
Ecuador 2002			7	5			7	5		7	5
United Kingdom 2004			1		4	2	5	2		5	2
United Kingdom 2003			2	1	5	3	7	4		7	4
United Kingdom 2002			7	3	2	1	9	4		9	4

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Gross**	**Net**
Continuing Operations:											
2004:											
Canada	3,632	3,419	386	364	16	15	4,034	3,798	1,105	5,139	3,798
United States	600	515	1		3	3	604	518		604	518
Total	4,232	3,934	387	364	19	18	4,638	4,316	1,105	5,743	4,316
2003:											
Canada	3,964	3,901	756	650	24	18	4,744	4,569	1,347	6,091	4,569
United States	426	401			1	1	427	402		427	402
Total	4,390	4,302	756	650	25	19	5,171	4,971	1,347	6,518	4,971
2002:											
Canada	1,397	1,340	433	349	30	23	1,860	1,712	690	2,550	1,712
United States	287	250	3	3	1	1	291	254		291	254
Total	1,684	1,590	436	352	31	24	2,151	1,966	690	2,841	1,966
Discontinued Operations:											
Ecuador 2004			43	25	1	1	44	26		44	26
Ecuador 2003			53	39	6	6	59	45		59	45
Ecuador 2002			44	37	5	4	49	41		49	41
United Kingdom 2004			3	1			3	1		3	1
United Kingdom 2003			3				3			3	
United Kingdom 2002			2				2			2	

Notes:

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

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

(3) At December 31, 2004, EnCana was in the process of drilling 33 gross wells (32 net wells) in Canada, 50 gross wells (45 net wells) in the United States, 4 gross wells (2 net wells) in Ecuador and no wells in other countries.

Location of Wells

The following table summarizes EnCana s interest in producing wells and wells capable of producing as at December 31, 2004:

	Gas		Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Continuing Operations:						
Alberta	29,790	27,943	4,700	4,151	34,490	32,094
British Columbia	1,329	1,196	16	10	1,345	1,206
Saskatchewan	336	332	1,177	515	1,513	847
Manitoba			3	3	3	3
Total Canada	31,455	29,471	5,896	4,679	37,351	34,150
Colorado	3,902	3,155			3,902	3,155
Texas	1,179	762	30	12	1,209	774
Wyoming	1,493	874			1,493	874
Montana	42	37			42	37
Utah	33	32			33	32
Oklahoma	47	12			47	12
Louisiana	4	2			4	2
Gulf of Mexico			6	1	6	1
Total United States	6,700	4,874	36	13	6,736	4,887
Total	38,155	34,345	5,932	4,692	44,087	39,037
Discontinued Operations:						
Ecuador			289	227	289	227

Notes:

(1) EnCana has varying royalty interests in 8,396 crude oil wells and 12,970 natural gas wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 26,879 gross natural gas wells (24,441 net wells) and 1,681 gross crude oil wells (1,393 net wells).

Interest in Material Properties

The following table summarizes EnCana s developed, undeveloped and total landholdings as at December 31, 2004:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	Fee	4,319	4,319	2,835	2,835	7,154	7,154
	Crown	3,709	2,989	6,643	5,578	10,352	8,567
	Freehold	185	101	245	192	430	293
		8,213	7,409	9,723	8,605	17,936	16,014
British Columbia	Crown	697	579	4,174	3,601	4,871	4,180
	Freehold			7	7	7	7
		697	579	4,181	3,608	4,878	4,187
Saskatchewan	Fee	57	57	461	461	518	518
	Crown	115	96	1,064	1,049	1,179	1,145
	Freehold	13	9	104	97	117	106
		185	162	1,629	1,607	1,814	1,769
Manitoba	Fee	3	3	265	265	268	268
	Freehold			23	23	23	23
		3	3	288	288	291	291
Newfoundland & Labrador	Crown			4,027	2,514	4,027	2,514
Nova Scotia	Crown			1,834	1,043	1,834	1,043
Northwest Territories	Crown			633	234	633	234
Nunavut	Crown			817	26	817	26
Beaufort	Crown			126	4	126	4
Total Canada		9,098	8,153	23,258	17,929	32,356	26,082

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
		(thousands of acres)					
United States							
Colorado	Federal/ State Lands	208	180	821	745	1,029	925
	Freehold	112	102	212	191	324	293
	Fee	3	3	60	60	63	63
		323	285	1,093	996	1,416	1,281
Washington	Federal/ State Lands			459	456	459	456
	Freehold			199	199	199	199
	Federal Acquired Lease			219	213	219	213
				877	868	877	868
Texas	Federal/ State Lands	8	3	205	204	213	207
	Freehold	161	97	431	395	592	492
		169	100	636	599	805	699
Wyoming	Federal/ State Lands	148	73	729	490	877	563
	Freehold	26	18	81	46	107	64
	Bureau of Indian Affairs	11	10	5	4	16	14
		185	101	815	540	1,000	641
Gulf of Mexico	Federal/ State Lands			1,371	557	1,371	557
Alaska	Federal/ State Lands			1,337	531	1,337	531
Other	Federal Lands	11	10	374	236	385	246
	Freehold	19	10	22	13	41	23
	Fee	1	1			1	1
		31	21	396	249	427	270
Total United States		708	507	6,525	4,340	7,233	4,847
Chad				108,536	54,268	108,536	54,268
Oman				9,606	9,606	9,606	9,606
Qatar				2,161	2,161	2,161	2,161
Greenland				985	862	985	862
Yemen				1,879	691	1,879	691

Brazil			1,444	554	1,444	554
Australia			960	320	960	320
Bahrain			97	48	97	48
Azerbaijan			346	17	346	17
Total International			126,014	68,527	126,014	68,527
Total	9,806	8,660	155,797	90,796	165,603	99,456
Discontinued Operations:						
Ecuador	160	99	1,243	795	1,403	894

Notes:

(1) This table excludes approximately 4.3 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. In prior years, fee lands in which any zones were leased out were excluded as fee lands except with respect to lands in which EnCana retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

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

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

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

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

Acquisitions, Dispositions and Capital Expenditures

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

The following table summarizes EnCana s net capital investment for 2003 and 2004.

	2004	2003
	($ millions)	
Upstream		
Canada	3,015	2,937
United States	1,249	830
International New Ventures Exploration	79	78
	4,343	3,845
Midstream & Marketing	64	223
Corporate	46	57
Core Capital from Continuing Operations	4,453	4,125
Acquisitions		
Upstream		
Property		
Canada	64	261
United States	300	138
Corporate		
Savannah		91
Petrovera	253	
Tom Brown, Inc. (1)	2,335	
Midstream & Marketing		
Other	34	53
Corporate		50
Dispositions		
Upstream		
Property		
Canada	(877)	(108)
United States	(266)	(178)
Other Countries		(15)
Corporate		
Petrovera	(540)	
Midstream & Marketing		
Property	(1)	
Corporate		
Alberta Ethane Gathering System Joint Venture	(108)	
Kingston CoGen Partnership	(25)	
Net Acquisition and Disposition Activity from Continuing Operations	1,169	292

Proceeds of Disposition of United Kingdom	(2,144)	
Discontinued Operations	728	(995)
Total Discontinued Operations	(1,416)	(995)

Note:

(1) Net cash consideration excluding debt acquired of $406 million.

EnCana plans to dispose of various non-core assets in 2005, including its interests in Ecuador, the Gulf of Mexico, select western Canadian conventional properties, U.S. gathering and processing assets and any other assets deemed to be non-core to the Corporation.

Delivery Commitments

As part of ordinary business operations, EnCana has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. These commitments comprise a small portion of EnCana s total revenues and the Corporation has sufficient reserves of natural gas and crude oil to meet these commitments. More detailed information relating to such commitments can be found in Note 19 to EnCana s audited consolidated financial statements for the year ended December 31, 2004.

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, licences and concessions, market access, 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 reviews and recommends to the Board of Directors for approval environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/ reclamation programs are in place and utilized to restore the environment.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2004, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2005.

Based on EnCana s current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at $3.7 billion.

Social and Environmental Policies

In 2003, EnCana developed a Corporate Responsibility Policy (the Policy) that translates its constitutional values and shared principles into policy commitments. The Policy applies to any activity undertaken by or on behalf of EnCana, anywhere in the world, associated with the finding, production, transmission and storage of the Corporation s products including decommissioning of facilities, marketing and other business and administrative functions. The Policy has specific requirements in areas related to (i) leadership commitment, (ii) sustainable value creation, (iii) governance and business practices, (iv) human rights, (v) labour practices, (vi) environment, health and safety, (vii) stakeholder engagement and (viii) socio-economic and community development.

Accountability for implementation of the Policy is at the operational level within EnCana s business units. Business units have established processes to evaluate risks, and programs are implemented to minimize that risk, which may include appropriate mitigation measures. Results related to the commitments outlined in the Corporate Constitution are tied to the individual performance assessment process.

With respect to human rights, the Policy states that: (i) while governments have the primary responsibility to promote and protect human rights, EnCana shares this goal and will support and respect human rights within its sphere of influence; (ii) EnCana will not take part in human rights abuse, and will not engage or be complicit in any activity that solicits or encourages human rights abuse; and (iii) in providing for the protection of company personnel and assets by public or private security forces, EnCana will promote respect for, and protection of, human rights.

The Policy states the following with respect to the environment: (i) EnCana will safeguard the environment, and will operate in a manner consistent with recognized global industry standards in environment, health and safety; (ii) in all of its operations, EnCana will strive to make efficient use of resources, to minimize its environmental footprint, and

to conserve habitat diversity and the plant and animal populations that may be affected by its operations; and (iii) EnCana will strive to reduce its emissions intensity and increase its energy efficiency.

With respect to EnCana s relationship with the communities in which it does business, the Policy states that: (i) EnCana emphasizes collaborative, consultative and partnership approaches in its community investment and programs, recognizing that no corporation is solely responsible for changing the fundamental economic, environmental and social situation in a community or country; and (ii) through its activities, EnCana will assist in local capacity-building and develop mutually beneficial relationships, to make a positive difference in the communities and regions where it operates.

Some of the steps that EnCana has taken to embed the corporate responsibility approach throughout the organization include: (i) implementation of a comprehensive on-line approach to training and communicating policies and practices, as well as face-to-face sessions; (ii) development and implementation of an environment, health and safety management system; (iii) development of a security program to regularly assess security threats to business operations and manage the associated risks; (iv) the introduction, in the first quarter of 2005, of a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide; (v) development of corporate responsibility performance metrics to track the Corporation s progress; (vi) contribution of a minimum of one percent of EnCana s pre-tax profits to charitable and non-profit organizations in the communities in which the company operates; and (vii) the adoption of related policies and practices such as an Alcohol and Drug Policy and Business Conduct and Ethics Practice. In addition, EnCana s Board of Directors approves such policies, is advised of significant contraventions thereof, and receives updates on trends, issues or events which could have a significant impact on the Corporation.

Employees

At December 31, 2004, EnCana employed 4,090 full time equivalent (FTE) employees as set forth in the following table:

	Number of FTE Employees As at December 31, 2004
Upstream	3,176
Midstream & Marketing	306
Corporate	608
Total	4,090

Foreign Operations

As at December 31, 2004, approximately 94 percent of EnCana s reserves and 89 percent of its production were located in North America, which limits EnCana s exposure to risks and uncertainties in countries considered politically and economically unstable. EnCana s operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of EnCana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. The Corporation has undertaken to mitigate these risks where practical and considered warranted.

Reorganizations

As discussed under Introductory Information in this annual information form, EnCana was formed through the Merger of AEC and PanCanadian on April 5, 2002. AEC remained in existence as an indirect wholly owned subsidiary of EnCana, and on January 1, 2003, AEC was amalgamated with EnCana.

As a general matter, EnCana reorganizes its subsidiaries as required to maintain proper alignment of its businesses. On January 1, 2005 EnCana completed a reorganization of its U.S. subsidiaries. The U.S. corporate structure had grown significantly due to corporate acquisitions, and a number of entities were merged in order to rationalize the structure and reduce administrative burdens.

DIRECTORS AND OFFICERS

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

Directors

Name and Municipality of Residence	**Director Since**[13]	**Principal Occupation**
Michael N. Chernoff[2,6] West Vancouver, British Columbia, Canada	1999	Corporate Director
Ralph S. Cunningham[2,3] Houston, Texas, United States	2003	Corporate Director
Patrick D. Daniel[1,5] Calgary, Alberta, Canada	2001	President & Chief Executive Officer Enbridge Inc. *(Energy delivery)*
Ian W. Delaney[3,4] Toronto, Ontario, Canada	1999	Executive Chairman Sherritt International Corporation *(Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)*
William R. Fatt[1,8] Toronto, Ontario, Canada	1995	Chief Executive Officer Fairmont Hotels & Resorts Inc. *(Hotels)*
Michael A. Grandin[3,5,6,9] Calgary, Alberta, Canada	1998	Dean of the Haskayne School of Business University of Calgary *(Education)*
Barry W. Harrison[1,4,10] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
Richard F. Haskayne, O.C., F.C.A.[3,4] Calgary, Alberta, Canada	1992	Chairman of the Board TransCanada Corporation *(Pipelines and energy services)*
Dale A. Lucas[1,5] Calgary, Alberta, Canada	1997	Corporate Director
Ken F. McCready[2,5,11] Calgary, Alberta, Canada	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
Gwyn Morgan Calgary, Alberta, Canada	1993	President & Chief Executive Officer EnCana Corporation
Valerie A. A. Nielsen[2,6] Calgary, Alberta, Canada	1990	Corporate Director
David P. O Brien[4,7,12] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
Jane L. Peverett[1] West Vancouver, British Columbia, Canada	2003	Chief Financial Officer British Columbia Transmission Corporation *(Electricity transmission)*

Dennis A. Sharp[2,4] Calgary, Alberta, Canada/ Montreal, Quebec, Canada	1998	Executive Chairman UTS Energy Corporation *(Oil and natural gas company)*
James M. Stanford, O.C.[1,3,6] Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Investment management)*

Notes:

(1) Audit Committee.

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

(3) Human Resources and Compensation Committee.

(4) Nominating and Corporate Governance Committee.

(5) Pension Committee.

(6) Reserves Committee.

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

(8) Mr. Fatt was a director of Unitel Communications Inc. (Unitel) in 1995 when it made a filing pursuant to the *Companies Creditors Arrangement Act* (Canada). Unitel instituted a compromise with creditors on December 8, 1995 and Mr. Fatt resigned as a director in January 1996.

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

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

(11) Mr. McCready was a director of Colonia Corporation when the company was placed into receivership in October 2000. The company came out of receivership in October 2001. Mr. McCready was a director, Chairman and Chief Executive Officer of Etho Power Corporation, a small private company, when it was assigned into bankruptcy on April 7, 2003.

(12) Mr. O Brien resigned as a director of Air Canada on November 26, 2003. On April 1, 2003, Air Canada obtained an order from the Ontario Superior Court of Justice providing creditor protection under the *Companies Creditors Arrangement Act* (Canada). Air Canada also made a concurrent petition under Section 304 of the U.S. Bankruptcy Code. On September 30, 2004, Air Canada announced that it had successfully completed its restructuring process and implemented its Plan of Arrangement.

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

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

At the date of this annual information form, there are 16 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 15 nominees listed in the above table (all but Mr. Haskayne who will be retiring from the Board) to serve until the close of the next annual meeting of shareholders, or until their respective successors are duly elected or appointed. Subject to mandatory retirement age restrictions which have been established by the Board of Directors, all of the directors shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	**Office**
Gwyn Morgan Calgary, Alberta, Canada	President & Chief Executive Officer
Randall K. Eresman Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer
Roger J. Biemans Denver, Colorado, United States	Executive Vice-President
Brian C. Ferguson Calgary, Alberta, Canada	Executive Vice-President, Corporate Development
R. William Oliver Calgary, Alberta, Canada	Executive Vice-President
Gerard J. Protti Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations
Drude Rimell Calgary, Alberta, Canada	Executive Vice-President, Corporate Services
John D. Watson Calgary, Alberta, Canada	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. Daniel was President and Chief Operating Officer of Interprovincial Pipe Line Corporation from May 1994 to January 2001.

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

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

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

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

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

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 22, 2005, directly or indirectly, or exercised control or direction over an aggregate of 1,234,169 Common Shares representing 0.28 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 2,049,484 additional Common Shares.

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

AUDIT COMMITTEE INFORMATION

The full text of the audit committee mandate is included in Appendix C of this annual information form.

Composition of the Audit Committee

The audit committee consists of six members, all of which are independent and financially literate. The Corporation has adopted the definition of independence as set out in Section 1.4 of the proposed amendments to Multilateral Instrument 52-110 *Audit Committees*, as published on October 29, 2004. The relevant education and experience of each audit committee member is outlined below:

Patrick D. Daniel

Mr. Daniel holds a Bachelor of Science (University of Alberta) and Masters of Science (University of British Columbia), both in chemical engineering. He also completed the Harvard Advanced Management Program. He is President and Chief Executive Officer and a director of Enbridge Inc. (energy delivery company). He is a director of a number of Enbridge subsidiaries and a director of the general partner of Enbridge Energy Partners, L.P. and Enbridge Energy Management, L.L.C. He is also a director and member of the Audit Committee of Enerflex Systems Ltd. (compression systems manufacturer) and a Trustee of Enbridge Commercial Trust, a subsidiary entity of Enbridge Income Fund.

William R. Fatt

Mr. Fatt holds a Bachelor of Arts in Economics (York University). He is the Chief Executive Officer and a director of Fairmont Hotels & Resorts Inc. (hotel management). He is also a director and member of the Audit Committee of Enbridge Inc. (energy delivery company), a director of Sun Life Financial Inc. (life insurers) and The Jim Pattison Group (private company), and Vice Chairman and Trustee of Legacy Hotels Real Estate Investment Trust.

Mr. Fatt is the former Chairman and Chief Executive Officer of FHR Holdings Inc. (formerly known as Canadian Pacific Hotels and Resorts, Inc.). He has served in a number of finance-related positions in his 30-year career, including Executive Vice President and Chief Financial Officer of Canadian Pacific Limited, Treasurer of CP Limited, Vice-President of Morgan Bank of Canada and Vice President and Treasurer of Hiram Walker Resources Ltd., among others.

Barry W. Harrison (Audit Committee Chair)

Mr. Harrison holds a Bachelor of Business Administration and Banking (Colorado College) and a Bachelor of Law (University of British Columbia). He is a Corporate Director and an independent businessman. Mr. Harrison is a director and President of Eastgate Minerals Ltd. (oil and gas) and a director and member of the Audit Committee of Eastshore Energy Ltd. (oil and gas). He is also a director and Chairman of the Audit Committees of The Wawanesa Mutual Insurance Company (property and casualty insurer) and its related companies, The Wawanesa Life Insurance Co. and its U.S. subsidiary, the Wawanesa General Insurance Co. He was Managing Director of Goepel Shields & Partners Inc. in Calgary.

Dale A. Lucas

Mr. Lucas holds a Bachelor of Science in Chemical Engineering and a Bachelor of Arts in Economics (University of Alberta). Mr. Lucas is a Corporate Director and is President of D.A. Lucas Enterprises Inc., a private company owned by Mr. Lucas and through which he consults internationally. During his 44-year career in the energy sector, he served the maximum 6-year term as a director of the New York Mercantile Exchange (NYMEX) and was past Chairman of the Alberta Petroleum Marketing Commission. He has held senior executive positions with J. Makowski Canada Ltd. (Calgary), J. Makowski Associates Inc. (Boston), BP Canada and BP Pipelines (San Francisco).

Jane L. Peverett

Ms. Peverett holds a Bachelor of Commerce (McMaster University) and a Masters of Business Administration (Queen s University), together with a designation as a Certified Management Accountant and a Canadian Security Analyst Certificate. She is the Chief Financial Officer of British Columbia Transmission Corporation (electrical transmission). In her 15-year career with the Westcoast Energy Inc./ Duke Energy Corporation group of companies, she held senior executive positions with Union Gas Limited (Ontario) including President, President and Chief Executive Officer, Senior Vice President Sales & Marketing and Chief Financial Officer, among others.

James M. Stanford, O.C.

Mr. Stanford holds a Doctor of Laws (Hon.) and a Bachelor of Science in Petroleum Engineering (University of Alberta), and a Doctor of Laws (Hon.) and a Bachelor of Science in Mining (Concordia University). He is President of Stanford Resource Management Inc. (investment management) and is a director of a number of publicly traded companies: Inco Limited (mining company), OPTI Canada Inc. (oilsands development and upgrading company), NOVA Chemicals Corporation (commodity chemical company) and Terasen Inc. (energy distribution and energy transportation company). He is Chairman of the Audit Committee of Inco Limited. Mr. Stanford was President and Chief Executive Officer of Petro-Canada (oil and gas company) for seven years and was Chief Operating Officer and President for three years.

The above list does not include David P. O Brien who is an ex officio member of the audit committee.

Pre-Approval Policies and Procedures

EnCana has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The audit committee of the Board of Directors has established a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the audit committee, but at the option of the audit committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the audit committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the next paragraph, the audit committee has delegated authority to the Chairman of the audit committee (or if the Chairman is unavailable, any other member of the committee) to pre-approve the provision of permitted

services by PricewaterhouseCoopers LLP which are not otherwise pre-approved by the audit committee, including the fees and terms of the proposed services (Delegated Authority). Any required determination about the Chairman s unavailability is required to be made by the good faith judgment of the applicable other member(s) of the audit committee after considering all facts and circumstances deemed by such member(s) to be relevant. All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full audit committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that has been pre-approved pursuant to Delegated Authority (i) may not exceed C$200,000, in the case of pre-approvals granted by the Chairman of the audit committee, and (ii) may not exceed C$50,000, in the case of pre-approvals granted by any other member of the audit committee.

All proposed services or the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the audit committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the audit committee or pursuant to Delegated Authority.

External Auditor Service Fees

The following table provides information about the fees billed to the Corporation for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2004 and 2003:

($ thousands)	**2004**	**2003**
Audit Fees(1)	3,177	1,977
Audit-Related Fees(2)	166	127
Tax Fees(3)	1,097	1,408
All Other Fees(4)	24	26
Total	4,464	3,538

Notes:

(1) Audit fees consist of fees for the audit of the Corporation s annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation s financial statements and are not reported as Audit Fees. During fiscal 2004 and 2003, the services provided in this category included due diligence reviews in connection with acquisitions and dispositions, research of accounting and audit-related issues, review of reserves disclosure and the completion of audits required by contracts to which the Corporation is a party.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2004 and 2003, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns and expatriate tax services.

(4) During fiscal 2004, the services provided in this category included the payment of maintenance fees associated with a research tool that grants access to a comprehensive library of financial reporting and assurance literature and a working paper documentation package used by the Corporation s internal audit group. During fiscal 2003, the services provided in this category included the review of EnCana s Corporate Responsibility Report and the payment of maintenance fees associated with a working paper documentation package used by the Corporation s internal audit group.

In 2003, $35,300 of the fees listed above billed by PricewaterhouseCoopers LLP in respect of tax services were approved by the audit committee pursuant to the *de minimus* exception provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X. EnCana did not rely on the *de minimus* exemption in 2004.

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. As of December 31, 2004 there were approximately 450.3 million Common Shares issued and outstanding and no Preferred Shares outstanding.

Common Shares

The holders of the Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors of the Corporation. The holders of the Common Shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per Common Share held at all such meetings. In the event of the liquidation, dissolution or winding up of the Corporation or other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Common Shares will be entitled to participate rateably in any distribution of the assets of the Corporation.

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Corporation. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date.

The Corporation has a shareholder rights plan (the Plan) that was adopted to ensure, to the extent possible, that all shareholders of the Corporation are treated fairly in connection with any take-over bid for the Corporation. The Plan creates a right that attaches to each present and subsequently issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited takeover bid, whereby a person acquires or attempts to acquire 20 percent or more of EnCana s Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquiror, from and after the separation time and before certain expiration times, to acquire one Common Share at 50 percent of the market price at the time of exercise. The Plan was reconfirmed at the 2004 annual meeting of shareholders and must be reconfirmed at every third annual meeting thereafter until it expires on July 30, 2011.

Preferred Shares

Preferred Shares may be issued in one or more series. The Board of Directors may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of the Preferred Shares are not entitled to vote at any meeting of the shareholders of the Corporation, but may be entitled to vote if the Corporation fails to pay dividends on that series of Preferred Shares. The First Preferred Shares are entitled to priority over the Second Preferred Shares and the Common Shares of the Corporation with respect to the payment of dividends and the distribution of assets of the Corporation in the event of any liquidation, dissolution or winding up of the Corporation s affairs.

CREDIT RATINGS

The following table outlines the ratings of the Corporation s debt as of December 31, 2004.

	Standard & Poor s Ratings Services (S&P)	**Moody s Investors Service (Moody s)**	**Dominion Bond Rating Service (DBRS)**
Senior Unsecured/Long-Term Rating	A-	Baa2	A (low)
Commercial Paper/Short-Term Rating	A-1 (low)	P-2	R-1 (low)
Outlook	Negative	Stable	Stable

S&P s long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A- by S&P is the third highest of eleven categories and indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. However, the obligor s capacity to meet its financial commitment on the obligation is still strong. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category. On September 8, 2004, S&P affirmed EnCana s long-term A- rating, removed the rating from CreditWatch with negative implications and assigned a negative outlook to the rating. The negative outlook status implies that the rating could remain the same or be lowered. S&P s Canadian commercial paper ratings scale ranges from A-1 (high) to C, representing the range from highest to lowest quality. A-1 (low) is the third highest of seven categories and indicates that the obligor has satisfactory capacity to meet its financial commitments.

Moody s long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody s is the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade obligations (i.e., they are subject to moderate credit risk). Such debt securities may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. Moody s short-term ratings are on a scale ranging from P-1 (highest quality) to NP (lowest quality). P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term obligations.

DBRS long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A (low) by DBRS is the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category. The high and low grades are not used for the AAA category. DBRS short-term ratings are on a scale ranging from R-1 (high) to D, representing the range from highest to lowest quality. R-1 (low) is the third highest of ten categories and indicates that the short-term debt is of satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgement circumstances so warrant.

MARKET FOR SECURITIES

All of the outstanding Common Shares of EnCana are listed and posted for trading on the Toronto Stock Exchange and the New York Stock Exchange under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2004.

	Toronto Stock Exchange Share Price Trading Range				**New York Stock Exchange Share Price Trading Range**			
	High	**Low**	**Close**	**Share Volume**	**High**	**Low**	**Close**	**Share Volume**
	(C$ per share)			(millions)	($ per share)			(millions)
2004								
January	56.00	51.00	51.58	36.4	43.43	39.00	39.10	9.2
February	58.25	51.29	57.84	27.5	43.60	38.36	43.45	10.4
March	59.27	54.22	56.69	35.5	44.25	40.62	43.12	9.9
April	59.73	53.75	53.80	30.3	44.73	39.18	39.22	13.7
May	57.70	52.99	54.55	29.2	42.05	38.05	39.35	12.5
June	58.85	53.55	57.62	25.8	43.41	39.45	43.16	9.7
July	60.60	56.55	58.90	26.3	45.75	42.83	44.32	10.7
August	59.94	52.30	53.66	28.4	45.50	39.95	41.10	12.1
September	59.46	53.40	58.35	26.7	46.92	41.09	46.30	10.6
October	62.81	57.90	60.40	36.1	50.26	46.10	49.40	15.1
November	68.20	59.61	67.80	40.5	57.43	48.85	57.03	19.8
December	70.02	63.13	68.40	33.1	57.30	51.59	57.06	18.7

In October 2004, EnCana received approval from the Toronto Stock Exchange (TSX) to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the Bid). Under the Bid, EnCana was entitled to purchase up to 5 percent of the Common Shares issued and outstanding on October 22, 2004, over a period ending October 28, 2005. In February 2005, EnCana received approval from the TSX to amend the Bid. Under the amended

Bid, EnCana is entitled to purchase up to 46.1 million Common Shares (10 percent of the public float on October 22, 2004). Purchases may be made through the facilities of the TSX and the New York Stock Exchange, in accordance with the policies and rules of each exchange. As of December 31, 2004, the Corporation had purchased approximately 14.8 million shares under the Bid. During 2004, EnCana purchased a total of approximately 20 million shares, for approximately $1.0 billion, under the terms of its Normal Course Issuer Bids.

The following table outlines the debt securities issued by the Corporation in 2004 that are not listed or quoted on an exchange.

Issuer	Principal Amount	Coupon	Issue Date	Maturity Date	Issue Price
EnCana Holdings Finance Corp.[(1)]	$1 billion	5.80%	May 13, 2004	May 1, 2014	99.614%
EnCana Corporation	$250 million	4.60%	August 4, 2004	August 15, 2009	99.838%
EnCana Corporation	$750 million	6.50%	August 4, 2004	August 15, 2034	99.123%

Note:

(1) EnCana Holdings Finance Corp. (EHF) is an indirect, wholly owned subsidiary of EnCana Corporation. The notes issued by EHF are fully and unconditionally guaranteed by EnCana Corporation.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2002 and 2003, cash dividends were paid to common shareholders at a rate of C$0.40 per share annually (C$0.10 per share quarterly). In 2004, EnCana began paying cash dividends to common shareholders in United States dollars at a rate of $0.40 per share annually ($0.10 per share quarterly). EnCana s Board of Directors has declared a dividend of $0.10 per share payable on March 31, 2005 to common shareholders of record on March 15, 2005.

LEGAL PROCEEDINGS

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in EnCana s favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity.

For information on legal proceedings related to EnCana s discontinued merchant energy trading operations refer to Risk Factors in this annual information form.

RISK FACTORS

If any event arising from the risk factors set forth below occurs, EnCana s business, prospects, financial condition, results of operation or cash flows could be materially adversely affected.

A substantial or extended decline in crude oil and natural gas prices could have a material adverse effect on EnCana.

EnCana s financial performance and condition are substantially dependent on the prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have an adverse effect on the Corporation s operations and financial condition and the value and amount of its proved reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors beyond the Corporation s control. Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by EnCana are affected primarily by North American supply and demand, weather conditions and by prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil and natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or result in unutilized long-term transportation commitments, all of which could have an adverse effect on the Corporation s revenues, profitability and cash flows.

The market prices for heavy oil are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, production costs associated with heavy oil are relatively higher than for lighter grades. Future price differentials are uncertain and any increase in the heavy oil differentials could have a material adverse effect on EnCana s business.

EnCana conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of EnCana s assets could be subject to financial downward revisions, and the Corporation s earnings could be adversely affected.

If EnCana fails to acquire or find additional crude oil and natural gas reserves, the Corporation s reserves and production will decline materially from their current levels.

EnCana s future crude oil and natural gas reserves and production, and therefore its cash flows, are highly dependent upon its success in exploiting its current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, the Corporation s reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited, EnCana s ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, there can be no guarantee that EnCana will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

EnCana s crude oil and natural gas reserve data and future net revenue estimates are uncertain.

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond the Corporation s control. The reserve data in this annual information form represents estimates only. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. EnCana s actual production, revenues, taxes and development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

EnCana s hedging activities could result in realized and unrealized losses.

The nature of the Corporation s operations results in exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. The Corporation monitors its exposure to such fluctuations and, where the Corporation deems it appropriate, utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in crude oil and natural gas prices, changes in interest rates or increases in the value of currencies relative to the United States dollar.

The terms of the Corporation s various hedging agreements may limit the benefit to the Corporation of commodity price increases, changes in interest rates or decreases in the value of currencies relative to the United States dollar. The Corporation may also suffer financial loss because of hedging arrangements if:

- the Corporation is unable to produce oil or natural gas to fulfill delivery obligations;
- the Corporation is required to pay royalties based on market or reference prices that are higher than hedged prices; or
- counterparties to the Corporation s hedging agreements are unable to fulfill their obligations under the hedging agreements.

The Corporation s business is subject to environmental legislation in all jurisdictions in which it operates and any changes in such legislation could negatively affect its results of operations.

All phases of the crude oil and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, environmental legislation).

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facility sites and other properties associated with EnCana s operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties and failure to comply with environmental legislation may result in the imposition of fines and penalties. Although it is not expected that the costs of complying with environmental legislation will have a material adverse effect on EnCana s financial condition or results of operations, no assurance can be made that the costs of complying with environmental legislation in the future will not have such an effect.

In 1994, the United Nations Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol (the Protocol) which requires, upon ratification, nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Canadian federal government ratified the Protocol and on February 16, 2005, the Protocol came into force internationally. Currently the upstream crude oil and natural gas sector is in discussions with various provincial and federal levels of government regarding the development of greenhouse gas regulations for the industry. It is premature to predict what impact these potential regulations could have on EnCana s sector but it is possible that EnCana would face increases in operating costs in order to comply with a greenhouse gas emissions target.

EnCana s operations are subject to the risk of business interruption and casualty losses.

The Corporation s business is subject to all of the operating risks normally associated with the exploration for and production of crude oil and natural gas and the operation of midstream facilities. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and crude oil spills, any of which could cause personal injury, result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EnCana s operations will be subject to all of the risks normally incident to the transportation, processing, storing and marketing of crude oil, natural gas and other related products, drilling of crude oil and natural gas wells, and the operation and development of crude oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

The occurrence of a significant event against which EnCana is not fully insured could have a material adverse effect on the Corporation s financial position.

Fluctuations in exchange rates could affect expenses or result in realized and unrealized losses.

Worldwide prices for crude oil and natural gas are set in U.S. dollars. However, many of the Corporation s expenses outside of the U.S. are denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact the Corporation s expenses and have an adverse effect on the Corporation s financial performance and condition.

In addition, the Corporation has significant U.S. dollar denominated long-term debt. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could result in realized and unrealized losses on U.S. dollar denominated long-term debt.

EnCana does not operate all of its properties and assets.

Other companies operate a small portion of the assets in which EnCana has interests. EnCana will have limited ability to exercise influence over operations of these assets or their associated costs. EnCana s dependence on the operator and other working interest owners for these properties and its limited ability to influence operations and associated costs could materially adversely affect the Corporation s financial performance. The success and timing of EnCana s activities on assets operated by others therefore will depend upon a number of factors that are outside of the Corporation s control, including:

- timing and amount of capital expenditures;
- the operator s expertise and financial resources;
- approval of other participants;
- selection of technology; and
- risk management practices.

The Corporation s foreign operations will expose it to risks from abroad which could negatively affect its results of operations.

Some of EnCana s operations and related assets are located in countries outside North America, some of which may be considered to be politically and economically unstable. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as taxation, nationalization, expropriation, inflation, currency fluctuations, increased regulation and approval requirements, governmental regulation and the risk of actions by terrorist or insurgent groups, any of which could adversely affect the economics of exploration or development projects.

EnCana s ability to complete projects is dependent on factors outside of its control.

The Corporation manages a variety of projects including exploration and development projects and the construction or expansion of facilities and pipelines. Project delays may delay expected revenues and project cost overruns could make projects uneconomic. The Corporation s ability to complete projects depends upon numerous factors beyond the Corporation s control. These factors include:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of equipment;
- the ability to access lands;
- inclement weather;
- unexpected cost increases;
- accidents;
- the availability of skilled labour; and
- regulatory matters.

Oil and natural gas exploration and production is subject to regulation and intervention by governments that can affect or prohibit the drilling and tie-in of wells, production, abandonment of fields and the construction or expansion of facilities. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Corporation s existing and planned projects.

EnCana may be adversely affected by legal proceedings related to its discontinued merchant energy trading operations.

An action has been filed by E. & J. Gallo Winery (Gallo) in the United States District Court, Eastern District of California, against EnCana Corporation and its wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), alleging that they engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indexes and wash trading. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. A motion by EnCana to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted.

In addition, EnCana Corporation and WD, along with other energy companies, have been named as defendants in several class action lawsuits in California and New York federal and state courts. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain essentially similar allegations as in the Gallo complaint. The New York lawsuits claim that the defendants alleged manipulation of natural gas price indexes resulted in higher prices of natural gas futures and option contracts traded on the New York Mercantile Exchange (NYMEX) during the period from January 1, 2000 to December 31, 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving WD and several other companies unrelated to the Corporation as the remaining defendants. Most of the California lawsuits have been consolidated in Nevada District Court and all of the New York lawsuits have been consolidated in New York District Court. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. As is customary, none of the class actions specify the amount of damages claimed. There is no assurance that there will not be other actions arising out of these allegations on behalf of the same or different classes.

EnCana intends to vigorously defend against any claims of liability alleged in these lawsuits; however, the Corporation cannot predict the outcome of these proceedings or the commencement or outcome of any future proceedings against EnCana or whether any such proceeding would lead to monetary damages which could have a material adverse effect on the Corporation s financial position.

EnCana is subject to indemnification obligations in connection with PanCanadian s spin-off from Canadian Pacific Limited.

In connection with PanCanadian s spin-off from Canadian Pacific Limited (CPL) on October 1, 2001, PanCanadian entered into an arrangement agreement with certain other parties to the spin-off which contains a number of representations, warranties and covenants, including (a) an agreement by each of the parties to indemnify and hold harmless each other party on an after-tax basis against any loss suffered or incurred resulting from a breach of a representation, warranty or covenant; and (b) a covenant that each party will not take any action, omit to take any action or enter into any transaction that could adversely impact certain tax rulings received in connection with the spin-off, including government opinions and related opinions of counsel and the assumptions upon which they were made. As PanCanadian s successor, EnCana is bound by the agreement. With respect to Canadian taxation, in addition to various transactions that the respective parties were prohibited from undertaking prior to the implementation of the CPL arrangement, after the implementation of the CPL arrangement, no party generally is permitted to dispose of or exchange more than 10 percent of its assets or, among other things, undergo an acquisition of control without severe adverse consequences where such disposition or acquisition of control is for Canadian tax purposes part of a series of transactions or events that includes the CPL arrangement, except in limited circumstances. Should the Corporation be found to have breached its representations and warranties or should the Corporation fail to satisfy the contractual covenants, EnCana would be obligated to indemnify the other parties to the arrangement agreement for losses incurred in connection with such breach or failure. In addition, the Corporation is required to indemnify the parties to the arrangement agreement against any loss which they may incur resulting from a claim against EnCana, their respective businesses or their respective assets, whether arising prior to or after the completion of the CPL arrangement. An indemnification claim against EnCana pursuant to the provisions of the arrangement agreement could have a material adverse effect upon the Corporation.

TRANSFER AGENTS AND REGISTRARS

In Canada:
CIBC Mellon Trust Company
320 Bay Street
P.O. Box 1
Toronto, ON M5H 4A6
Tel: 1-800-387-0825
Web site: www.cibcmellon.com

In the United States:
Mellon Investor Services LLC
44 Wall Street, 6th Floor
New York, New York
10005
Tel: 1-800-387-0825
Web site: www.cibcmellon.com

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Corporation s auditors and such firm has prepared an opinion with respect to the Corporation s consolidated financial statements as at and for the fiscal year ended December 31, 2004. Information relating to reserves in this annual information form dated February 25, 2005 was calculated by Gilbert Laustsen Jung Associates Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton as independent qualified reserves evaluators.

The principals of each of Gilbert Laustsen Jung Associates Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of EnCana s securities.

ADDITIONAL INFORMATION

Additional information relating to EnCana is available via the System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com.

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 and Management s Discussion and Analysis for the year ended December 31, 2004.

APPENDIX A
Report on Reserves Data by Independent Qualified Reserves Evaluators

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

1. We have evaluated the Corporation s reserves data as at December 31, 2004. The reserves data consist of the following:
   (i) estimated proved oil and gas reserve quantities as at December 31, 2004 using constant prices and costs; and

   (ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserve quantities.
2. The reserves data are the responsibility of the Corporation s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the FASB Standards) and the legal requirements of the U.S. Securities and Exchange Commission (SEC Requirements).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions outlined above.

4. The following table sets forth both the estimated proved reserve quantities (after royalties) and related estimates of future net cash flows (before deduction of income taxes) assuming constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2004:

		Estimated Proved Reserve Quantities After Royalty		**Related Estimates of Future Net Cash Flow BTax, 10% discount rate**
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	
		(Bcf)	(MMbbl)	($USMM)
McDaniel & Associates Consultants Ltd. January 14, 2005	Canada	3,434	146	9,770
Gilbert Laustsen Jung Associates Ltd. January 14, 2005	Canada	2,390	121	6,529
Netherland, Sewell & Associates, Inc. January 14, 2005	United States	3,946	49	9,276
DeGolyer and MacNaughton February 3, 2005	United States	690	42	1,907
Gilbert Laustsen Jung Associates Ltd. January 14, 2005	Ecuador		143	1,752
Totals		10,460	501	29,234

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

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

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

Executed as to our report referred to above:

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

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

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

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

February 14, 2005

APPENDIX B

Report of Management and Directors on Reserves Data and Other Information

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

(i) proved oil and gas reserve quantities estimated as at December 31, 2004 using constant prices and costs; and

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

Independent qualified reserves evaluators have evaluated the Corporation s reserves data. A report from the independent qualified reserves evaluators dated February 14, 2005 (the IQRE Report), highlighting the standards they followed and their results, accompanies this Report.

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

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

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

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

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

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

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

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

(signed) Gwyn Morgan
President & Chief Executive Officer
(signed) Brian C. Ferguson
Executive Vice-President, Corporate Development
(signed) David P. O Brien
Director and Chairman of the Board
(signed) James M. Stanford
Director and Chairman of the Reserves Committee
February 22, 2005

APPENDIX C
Audit Committee Mandate

I. PURPOSE

The Audit Committee (the Committee) is appointed by the Board of Directors of EnCana Corporation (the Corporation) to assist the Board in fulfilling its oversight responsibilities.

The Committee s primary duties and responsibilities are to:

Review and approve management s identification of principal financial risks and monitor the process to manage such risks.

Oversee and monitor the Corporation s compliance with legal and regulatory requirements.

Receive and review the reports of the Audit Committee of any subsidiary with public securities.

Oversee and monitor the integrity of the Corporation s accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance.

Oversee audits of the Corporation s financial statements.

Oversee and monitor the qualifications, independence and performance of the Corporation s external auditors and internal auditing department.

Provide an avenue of communication among the external auditors, management, the internal auditing department, and the Board of Directors.

Report to the Board of Directors regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

II. COMPOSITION AND MEETINGS

Committee Member s Duties in addition to those of a Director

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board of Directors.

Composition

The Committee shall consist of not less than five and not more than eight Directors as determined by the Board, all of whom shall qualify as unrelated Directors and who are free from any relationship that would interfere with the exercise of his or her independent judgement.

All members of the Committee shall be financially literate, as defined by the Board, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

An understanding of generally accepted accounting principles and financial statements;

The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the registrant s financial statements, or experience actively supervising one or more persons engaged in such activities;

An understanding of internal controls and procedures for financial reporting; and

An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an affiliated person (as such term is defined in the United States Securities Exchange Act of 1934, as amended, and the rules adopted by the SEC thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, director s fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an audit committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chairman shall be a non-voting member of the Committee.

Appointment of Members

Committee members shall be appointed at a meeting of the Board, effective after the election of Directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

The Nominating and Corporate Governance Committee will recommend for approval to the Board an unrelated Director to act as Chairman of the Committee. The Board shall appoint the Chairman of the Committee.

If the Chairman of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of the members of the Committee present at such meeting.

The Chairman of the Committee presiding at any meeting of the Committee shall not have a casting vote.

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Corporate Secretary or one of the Assistant Corporate Secretaries of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

Meetings

Committee meetings may, by agreement of the Chairman of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

The Committee shall meet at least quarterly. The Chairman of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chairman, the President & Chief Executive Officer, or any member of the Committee or by the external auditors.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chairman or by a majority of the members of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer, the Comptroller and the head of internal audit are expected to be available to attend the Committee s meetings or portions thereof.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, in writing, by electronic communication, or by facsimile to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member s presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Minutes

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors.

The full Board of Directors shall be kept informed of the Committee s activities by a report following each Committee meeting.

III. RESPONSIBILITIES

Review Procedures

Review and update the Committee s mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee s composition and responsibilities in the Corporation s annual report or other public disclosure documentation.

Provide a summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation s annual report filed with the United States Securities and Exchange Commission.

Annual Financial Statements

1. Discuss and review with management and the external auditors the Corporation s and any subsidiary with public securities annual audited financial statements and related documents prior to their filing or distribution. Such review to include:
   a. The annual financial statements and related footnotes including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Corporation s selection or application of accounting principles, any major issues as to the adequacy of the Corporation s internal controls and any special steps adopted in light of material control deficiencies.

   b. Management s Discussion and Analysis.

   c. A review of the use of off-balance sheet financing including management s risk assessment and adequacy of disclosure.

   d. A review of the external auditors audit examination of the financial statements and their report thereon.

   e. Review of any significant changes required in the external auditors audit plan.

   f. A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors work or access to required information.

g. A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Review and formally recommend approval to the Board of the Corporation s:
   a. Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:
      (i) The accounting policies of the Corporation and any changes thereto.

      (ii) The effect of significant judgements, accruals and estimates.

      (iii) The manner of presentation of significant accounting items.

      (iv) The consistency of disclosure.
   b. Management s Discussion and Analysis.

   c. Annual Information Form as to financial information.

   d. All prospectuses and information circulars as to financial information.

The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation s financial status depends, and which involve the most complex, subjective or significant judgemental decisions or assessments.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation s:
   a. Quarterly unaudited financial statements and related documents, including Management s Discussion and Analysis.

   b. Any significant changes to the Corporation s accounting principles.

Review quarterly unaudited financial statements of any subsidiary of the Corporation with public securities prior to their distribution.

Other Financial Filings and Public Documents

4. Review and discuss with management financial information, including earnings press releases, the use of pro forma or non-GAAP financial information and earnings guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies) and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made).

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee an annual report on the Corporation s control environment as it pertains to the Corporation s financial reporting process and controls.

6. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

7. Review significant findings prepared by the external auditors and the internal auditing department together with management s responses.

8. Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and

discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers and directors expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

10. Review all related party transactions between the Corporation and any officers or directors, including affiliations of any officers or directors.

11. Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation s monitoring compliance with each of the Corporation s published codes of business conduct and applicable legal requirements.

12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, that may have a material impact on the interim or annual financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies. Members from the Legal and Tax departments should be at the meeting in person to deliver their reports.

13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

14. Ensure that the Corporation s presentations on net proven reserves have been reviewed with the Reserves Committee of the Board.

15. Establish procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters.

16. Review with the President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation s internal controls and procedures for financial reporting which could adversely affect the Corporation s ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the United States Securities Exchange Act of 1934, as amended (the Exchange Act) or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Corporation or other employees who have a significant role in the Corporation s internal controls and procedures for financial reporting.

17. Meet on a periodic basis separately with management.

External Auditors

18. Be directly responsible, in the Committee s capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

19. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chairman of the Committee or by a majority of the members of the Committee.

20. Review and discuss a report from the external auditors at least quarterly regarding:
    a. All critical accounting policies and practices to be used;

    b. All alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

    c. Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

21. Obtain and review a report from the external auditors at least annually regarding:
    a. The external auditors internal quality-control procedures.

    b. Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.

    c. To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.
22. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors report to satisfy itself of the external auditors independence.

23. Review and evaluate:
    a. The external auditors and the lead partner of the external auditors team s performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation s shareholders or regarding the discharge of such external auditors.

    b. The terms of engagement of the external auditors together with their proposed fees.

    c. External audit plans and results.

    d. Any other related audit engagement matters.

    e. The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.
24. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 20 through 23, evaluate the external auditors qualifications, performance and independence, including whether or not the external auditors quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present its conclusions with respect to the external auditors to the Board.

25. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

26. Set clear hiring policies for the Corporation s hiring of employees or former employees of the external auditors.

27. Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

28. Consider and review with the external auditors, management and the head of internal audit:
    a. Significant findings during the year and management s responses and follow-up thereto.

b. Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management s response.

c. Any significant disagreements between the external auditors or internal auditors and management.

d. Any changes required in the planned scope of their audit plan.

e. The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.

f. The internal audit department mandate.

g. Internal audit s compliance with the Institute of Internal Auditors standards.

Internal Audit Department and Legal Compliance

29. Meet on a periodic basis separately with the head of internal audit.

30. Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

31. Confirm and assure, annually, the independence of the internal audit department and the external auditors.

Approval of Audit and Non-Audit Services

32. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the de minimus exception for non-audit services described in the Exchange Act or applicable Canadian federal and provincial legislation and regulations which are approved by the Committee prior to the completion of the audit).

33. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

34. If the pre-approvals contemplated in paragraphs 32 and 33 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

35. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 32 through 34. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

36. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 32 and 33, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee s responsibilities under the Exchange Act or applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

37. Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

38. Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

39. Report Committee actions to the Board of Directors with such recommendations, as the Committee may deem appropriate.

40. Conduct or authorize investigations into any matters within the Committee s scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

41. The Corporation shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

42. Obtain assurance from the external auditors that disclosure to the Committee is not required pursuant to the provisions of the Exchange Act regarding the discovery of illegal acts by the external auditors.

43. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

44. The Committee s performance shall be evaluated annually by the Nominating and Corporate Governance Committee of the Board of Directors.

45. Perform such other functions as required by law, the Corporation s mandate or bylaws, or the Board of Directors.

46. Consider any other matters referred to it by the Board of Directors.

ENCANA CORPORATION

2004
Management s Discussion and Analysis

MANAGEMENT S DISCUSSION & ANALYSIS

This Management s Discussion and Analysis (MD&A) for EnCana Corporation (EnCana or the Company) should be read in conjunction with the audited Consolidated Financial Statements (Consolidated Financial Statements) for the year ended December 31, 2004, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2003. Readers are referred to the legal advisory detailing Forward-Looking Statements contained in the back of this MD&A. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in United States dollars (except where indicated as being in another currency).

This MD&A has been prepared in United States dollars with production and sales volumes presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 22, 2005.

SUMMARY OF KEY SECTIONS

Certain terms used in this MD&A (and not otherwise defined) are defined in the notes regarding Oil and Gas Information, Currency, Non-GAAP Measures and References to EnCana, found at the end of this MD&A.

SUMMARY OF KEY EVENTS AND FINANCIAL RESULTS IN 2004

Total sales volumes increased 16 percent to 4,560 million cubic feet of gas (MMcf) equivalent per day (MMcfe/d) comprised of 2,998 MMcf/d of natural gas and 260,383 barrels per day (bbls/d) of liquids.

Average sales prices, excluding financial hedges, increased 12 percent for North American natural gas and 27 percent for North American liquids.

EnCana recorded total realized commodity and currency hedging losses of approximately $0.7 billion after tax.

EnCana purchased approximately 20 million shares under the Normal Course Issuer Bid for a total cost of $1 billion.

As part of the sharpening of EnCana s strategic focus to unconventional resource plays, the Company:

Acquired Tom Brown, Inc. (TBI) on May 19, 2004 for approximately $2.7 billion, contributing approximately 194 MMcfe/d to EnCana s annual production;

- Sold its United Kingdom (U.K.) operations for approximately $2.1 billion on December 1, 2004;
- Completed approximately $1.4 billion in mature, North American conventional property dispositions during 2004; and
- Initiated a strategic review of its Ecuador assets and has announced that these assets are for sale.

OVERVIEW

EnCana is a leading independent North American oil and gas company. EnCana pursues predictable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. EnCana s disciplined pursuit of these unconventional resources has enabled it to become North America s leading natural gas producer and a technical and cost performance leader in the development of oilsands through in-situ recovery.

EnCana reports the results of its continuing operations under two business segments:

- Upstream, which focuses on the Company s exploration for and development and production of natural gas, crude oil and natural gas liquids (NGLs), and other related activities.
- Midstream & Market Optimization, which is conducted by the Midstream & Marketing division. Midstream focuses on natural gas storage operations, NGLs processing and power generation operations. Marketing undertakes market optimization activities to enhance the sale of Upstream s proprietary production. Market optimization results reflect third party purchases and sales of product which provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

BUSINESS ENVIRONMENT

NATURAL GAS

Lack of overall North American industry natural gas supply combined with increasing demand and the influence of high crude oil prices have continued to result in historically high average NYMEX gas prices. Higher average AECO gas prices in 2004 can be attributed to an increased NYMEX index partially offset by wider AECO differentials from NYMEX combined with the appreciation of the U.S./Canadian dollar exchange rate. The increased AECO/NYMEX basis differential in 2004 compared to 2003 can be attributed to increased transportation differentials for the incremental sales volumes transported from Alberta to Eastern Canada.

Natural Gas Price Benchmarks

(average for the period)	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
AECO Price *(C$/Mcf)*	**$ 6.79**	**1%**	$ 6.70	65%	$ 4.07
NYMEX Price *($/MMBtu)*	**6.14**	**14%**	5.39	67%	3.22
Rockies (Opal) Price *($/MMBtu)*	**5.23**	**27%**	4.12	103%	2.03
AECO/NYMEX Basis Differential *($/MMBtu)*	**0.91**	**40%**	0.65	-2%	0.66
Rockies/NYMEX Basis Differential *($/MMBtu)*	**0.91**	**-28%**	1.27	7%	1.19

CRUDE OIL

The West Texas Intermediate (WTI) crude oil price was significantly higher both in the fourth quarter and for the year of 2004 compared to the corresponding periods in 2003. This was caused by continued world oil demand strength, primarily in Asia and North America, and during the fourth quarter, concerns over winter heating oil supplies in North America. The world oil price in the fourth quarter was further supported by supply uncertainties in the Middle East and West Africa, as well as reduced supply from the Gulf of Mexico, the North Sea, Russia and Canada. OPEC s reaction to high prices resulted in an increase in production over the course of the year. However, the incremental production was a heavier and more sour blend of crude oil than WTI and put added pressure on light to heavy oil price differentials.

The WTI/Bow River heavy oil differential widened in the fourth quarter of 2004 to record levels primarily due to the higher price for WTI, as well as wider U.S. Gulf Coast light to heavy product differentials and increased Canadian heavy crude-on-crude competition. As a percentage of WTI, Bow River Blend average sales price for the fourth quarter of 2004 was 60 percent of WTI compared to 69 percent in the fourth quarter of 2003.

On a year over year basis, the WTI/Bow River heavy oil differential was higher primarily as a result of the increase in WTI. NAPO blend in Ecuador is a heavier crude than the SOTE Oriente blend (previously the predominant crude oil from Ecuador) resulting in a wider differential to WTI. The fourth quarter and annual 2004 increases in the WTI/Oriente differential compared to the same periods in 2003 are primarily related to the increase in the WTI price as well as wider U.S. Gulf Coast light to heavy product differentials.

Crude Oil Price Benchmarks

	2004 vs	2003 vs

(average for the period, unless otherwise noted)	**2004**	**2003**	**2003**	2002	2002
WTI *($/bbl)*	**$ 41.47**	**34%**	$ 30.99	19%	$ 26.15
Dated Brent *($/bbl)*	**38.27**	**33%**	28.83	15%	25.02
WTI/Bow River Differential *($/bbl)*	**12.82**	**60%**	8.01	35%	5.93
WTI/OCP NAPO Differential (Ecuador) *($/bbl)* [(1)]	**14.33**	**78%**	8.06		
WTI/Oriente Differential (Ecuador) *($/bbl)*	**11.12**	**99%**	5.59	34%	4.16

(1) The WTI/ OCP NAPO Differential was posted as of September 2003.

U.S./CANADIAN DOLLAR EXCHANGE RATES

The 2004 year-end U.S./Canadian dollar exchange rate of US$0.831 per C$1 increased by seven percent compared with the 2003 year-end rate of $0.774. The 2003 year-end rate increased by 22 percent when compared with the 2002 year-end rate of $0.633.

The increased value of the Canadian dollar has resulted primarily from continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit.

CONSOLIDATED FINANCIAL RESULTS

SUMMARY

2004 vs. 2003
Cash flow increased to $5 billion from $4.5 billion, an increase of $0.5 billion or $1.34 per share diluted. Higher commodity prices and growth in sales volumes were partially offset by realized financial commodity and currency hedge losses and increased expenses. Cash flow from continuing operations also increased $0.5 billion, or $1.22 per share diluted, to a total of $4.6 billion in 2004 compared to $4.1 billion in 2003.

Net earnings increased $1.1 billion to $3.5 billion in 2004. Included in net earnings is a $1.4 billion gain on the sale of the U.K. discontinued operations. EnCana s net earnings from continuing operations in 2004 are $2.2 billion compared with $2.1 billion in 2003. Higher volumes and prices in 2004 were offset by increased expenses and increased depreciation, depletion and amortization (DD&A). Net earnings in 2004 include an unrealized after tax gain of $229 million on Canadian issued U.S. denominated debt resulting from the increase in the value of the Canadian dollar and an unrealized after tax mark-to-market accounting loss of $165 million.

2003 vs. 2002
Cash flow increased 84 percent and net earnings increased 191 percent compared with 2002 as a result of growth in sales volumes, higher commodity prices and the inclusion of a full year of post merger operations, partially offset by increased expenses.

Net earnings for the year also included an unrealized after-tax gain on the U.S. denominated debt issued in Canada of $433 million, or $0.90 per share diluted resulting from the increase in the value of the Canadian dollar versus the U.S. dollar, and a $359 million, or $0.75 per share diluted recovery of future income taxes resulting from reductions in the Canadian federal and Alberta corporate income tax rates.

Cash flow from continuing operations and net earnings from continuing operations increased 101 percent and 222 percent, respectively, compared to 2002.

ACQUISITIONS AND DIVESTITURES

In May 2004, the Company successfully completed its cash tender offer for all of the outstanding common shares of TBI which became an indirect wholly owned subsidiary following the merger of TBI and another of the Company s indirect wholly owned subsidiaries. The total consideration was approximately $2.3 billion plus the assumed debt of TBI of approximately $0.4 billion. The TBI assets are primarily strong growth long-life North American resource play assets, contributing approximately 194 MMcfe/d (32,300 BOE/d) to EnCana s annual production in 2004, which complement existing Company assets and are consistent with management s strategic focus.

In December 2004, a subsidiary of the Company sold its U.K. operations for approximately $2.1 billion. These assets included interests in the Buzzard, Scott and Telford oil fields, plus interests in other satellite discoveries and exploration licences in the U.K. central North Sea. In the first quarter of 2004, an EnCana subsidiary completed the purchase, through two separate transactions, of additional interests in the North Sea, for net cash consideration of approximately $131 million.

In line with the Company s strategy of focusing on its inventory of North American resource play assets in 2004, the Company disposed of a number of mature conventional producing assets. The Company recorded proceeds of approximately $1.1 billion on the sales of conventional oil and natural gas assets which were primarily located in western Canada. At the time of disposition, these assets were producing approximately 200 MMcfe/d (33,770 BOE/d).

In February 2004, the Company sold its 53.3 percent partnership interest in Petrovera Resources (Petrovera) for net cash consideration of approximately $287 million including working capital adjustments. Petrovera s production was approximately 120 MMcfe/d (20,000 BOE/d) of primarily heavy crude oil at the time of disposition.

In December 2004, the Company sold its interest in the Alberta Ethane Gathering System for approximately $108 million.

Proceeds received from the non-core divestitures described above have been used to repay debt, purchase EnCana shares and for general corporate purposes.

Consolidated Financial Summary *($ millions, except per share amounts)*	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
Cash Flow[1]	**$ 4,980**	**12%**	$ 4,459	84%	$ 2,419
- per share basic	**10.82**	**15%**	9.41	63%	5.79
- per share diluted	**10.64**	**14%**	9.30	63%	5.72
Net Earnings	**3,513**	**49%**	2,360	191%	812
- per share basic	**7.63**	**53%**	4.98	157%	1.94
- per share diluted	**7.51**	**53%**	4.92	156%	1.92
Operating Earnings[2]	**1,976**	**41%**	1,399	78%	787
- per share diluted	**4.22**	**45%**	2.92	57%	1.86
Cash Flow from Continuing Operations[1]	**4,605**	**11%**	4,135	101%	2,059
- per share basic	**10.00**	**15%**	8.72	77%	4.93
- per share diluted	**9.84**	**14%**	8.62	77%	4.87
Net Earnings from Continuing Operations	**2,211**	**3%**	2,142	222%	666
- per share basic	**4.80**	**6%**	4.52	184%	1.59
- per share diluted	**4.72**	**6%**	4.47	183%	1.58
Operating Earnings from Continuing Operations [2]	**1,989**	**47%**	1,350	115%	629
- per share diluted	**4.25**	**51%**	2.82	89%	1.49
Revenues, Net of Royalties	**11,810**	**22%**	9,686	63%	5,928
Total Assets	**31,213**	**29%**	24,110	21%	19,912
Long-Term Debt	**7,742**	**27%**	6,088	21%	5,051
Cash Dividends[3]	**183**	**32%**	139	29%	108

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under Cash Flow in this MD&A.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings in this MD&A.

(3) Represents cash dividends paid to common shareholders at the rate of US$0.40 per share annually except for 2003 and 2002 which were paid at the rate of C$0.40 per share annually.

Quarterly Summary	**2004**				2003			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Cash Flow[1]	**$ 1,491**	**$ 1,363**	**$ 1,131**	**$ 995**	$ 1,254	$ 977	$ 1,007	$ 1,221
- per share basic	**3.25**	**2.95**	**2.46**	**2.16**	2.71	2.06	2.10	2.54
- per share diluted	**3.21**	**2.92**	**2.43**	**2.13**	2.69	2.04	2.08	2.52

Net Earnings	**2,580**	**393**	**250**	**290**	426	290	807	837
- per share basic	**5.62**	**0.85**	**0.54**	**0.63**	0.92	0.61	1.68	1.74
- per share diluted	**5.55**	**0.84**	**0.54**	**0.62**	0.91	0.61	1.67	1.73
Operating Earnings[2]	**573**	**559**	**379**	**465**	316	278	277	528
- per share diluted	**1.23**	**1.20**	**0.81**	**1.00**	0.68	0.58	0.57	1.09
Cash Flow from Continuing Operations[1]	**1,429**	**1,259**	**1,021**	**896**	1,103	918	990	1,124
- per share basic	**3.11**	**2.73**	**2.22**	**1.94**	2.39	1.94	2.06	2.34
- per share diluted	**3.07**	**2.70**	**2.19**	**1.92**	2.37	1.92	2.04	2.32
Net Earnings from Continuing Operations	**1,188**	**432**	**265**	**326**	447	266	801	628
- per share basic	**2.59**	**0.94**	**0.58**	**0.71**	0.97	0.56	1.67	1.31
- per share diluted	**2.56**	**0.93**	**0.57**	**0.70**	0.96	0.56	1.65	1.30
Operating Earnings from Continuing Operations[2]	**612**	**553**	**362**	**462**	337	254	271	488
- per share diluted	**1.32**	**1.19**	**0.78**	**0.99**	0.72	0.53	0.56	1.01
Revenues, Net of Royalties	**4,208**	**2,320**	**2,552**	**2,730**	2,639	2,190	2,233	2,624

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under Cash Flow in this MD&A.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings in this MD&A.

CASH FLOW
EnCana s cash flow increased to $4,980 million in 2004, an increase of $521 million from 2003. This increase reflects the Company s overall 16 percent sales volume growth, increased prices in 2004, realized hedge losses, realized foreign exchange gains and an increase in the current income tax provision. EnCana s discontinued operations contributed $375 million to cash flow in 2004, an increase of $51 million from 2003.

EnCana s 2004 cash flow from continuing operations increased $470 million, or $1.22 per share diluted, to $4,605 million over 2003 with significant items as follows:

Natural gas sales volumes increased 16 percent to 2,968 MMcf/d.

Average North American natural gas prices, excluding financial hedges, were $5.47 per Mcf in 2004 compared to $4.87 per Mcf in 2003, an increase of 12 percent.

Average North American liquids prices, excluding financial hedges, were $28.77 per bbl in 2004 compared to $22.72 per bbl in 2003, an increase of 27 percent.

Realized financial commodity and currency hedge losses included in cash flow from continuing operations were approximately $686 million ($464 million after-tax) in 2004 compared to $259 million ($164 million after-tax) for 2003.

Realized foreign exchange gains of $190 million ($154 million after-tax) on the settlement of long-term debt in 2004 compared to realized gains of $86 million ($68 million after-tax) in 2003, as a result of the rise in the U.S./Canadian dollar exchange rate and its impact on the settlement of Canadian issued U.S. denominated debt.

Current income tax provision increased by $680 million to $567 million in 2004 from a recovery of $113 million in 2003 partially offsetting increased cash flow from higher volumes and prices.

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors to measure the Company s ability to finance its capital programs and meet its credit obligations. The calculation of cash flow is disclosed on the Consolidated Statement of Cash Flows in the Consolidated Financial Statements.

NET EARNINGS
EnCana s net earnings increased $1,153 million to $3,513 million in 2004. Included in 2004 net earnings is a gain of $1,364 million on the sale of EnCana s U.K. operations.

EnCana s net earnings from continuing operations increased $69 million, or $0.25 per share diluted in 2004 compared with 2003. In addition to the items affecting cash flow as detailed previously, significant items are:

Unrealized mark-to-market losses of $190 million ($116 million after-tax) are included in 2004 with no corresponding amount in 2003.

Included in 2004 is a gain due to a change in tax rates of $109 million, compared to a gain of $359 million in 2003.

A $285 million ($229 million after-tax) unrealized gain on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $545 million ($433 million after-tax) in 2003. This results from the continued strengthening in the year-end U.S./Canadian dollar exchange rate between December 31, 2003 and December 31, 2004 compared to the change between December 31, 2002 and December 31, 2003.

The impacts on results from the conversion of Canadian to U.S. dollars should be considered when analyzing specific components contained in the Consolidated Financial Statements. For every 100 Canadian dollars spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs of approximately US$5.20 based on the increase in the average U.S./Canadian dollar exchange rate from $0.716 in 2003 to $0.768 in 2004. Revenues were relatively unaffected by the increase in the exchange rate since commodity prices received are largely based in U.S. dollars or in Canadian dollar prices which are closely tied to the value of the U.S. dollar.

Reconciliation of Net Earnings from Continuing Operations from 2003 to 2004 (*$millions*)

2003 net earnings from continuing operations	**$ 2,142**
Upstream prices	915[1]
Upstream volumes	864
Gain on disposition of investments	112
Realized foreign exchange gain on long-term debt	79
Unrealized fair value adjustment on financial contracts	(190)
Unrealized foreign exchange gain on long-term debt	(260)
Income tax	(294)
Upstream expenses	(344)
DD&A costs	(413)
Realized loss on financial contracts	(427)
Other	27
2004 net earnings from continuing operations	**$ 2,211**

(1) Excludes the effect of upstream financial hedging.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that show net earnings excluding non-operating items such as the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates. Management believes these items reduce the comparability of the Company s underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. The following table has been prepared in order to provide shareholders and potential investors with information that is more comparable between years.

Summary of Operating Earnings

($ millions)	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
Net Earnings, as reported	**$ 3,513**	**49%**	$ 2,360	191%	$ 812
Deduct: (Gain) loss on discontinuance	**(1,364)**		(169)		12
Add: Unrealized mark-to-market accounting loss (after-tax)(2)	**165**				
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(229)**		(433)		(17)
Deduct: Future tax recovery due to tax rate reductions	**(109)**		(359)		(20)
Operating Earnings (1)(3)	**$ 1,976**	**41%**	$ 1,399	78%	$ 787
($ per Common Share Diluted)					
Net Earnings, as reported	**$ 7.51**	**53%**	$ 4.92	156%	$ 1.92
Deduct: (Gain) loss on discontinuance	**(2.92)**		(0.35)		0.03
Add: Unrealized mark-to-market accounting loss (after-tax)(2)	**0.35**				
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(0.49)**		(0.90)		(0.04)
Deduct: Future tax recovery due to tax rate reductions	**(0.23)**		(0.75)		(0.05)
Operating Earnings (1)(3)	**$ 4.22**	**45%**	$ 2.92	57%	$ 1.86

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(1) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively on January 1, 2004. See Note 2 to the Consolidated Financial Statements.

(3) Unrealized (gains)/ losses have no impact on cash flow.

Summary of Operating Earnings from Continuing Operations

($ millions)	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
Net Earnings from Continuing Operations, as reported	**$ 2,211**	**3%**	$ 2,142	222%	$ 666
Add: Unrealized mark-to-market accounting loss (after-tax)(2)	**116**				
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(229)**		(433)		(17)
Deduct: Future tax recovery due to tax rate reductions	**(109)**		(359)		(20)
Operating Earnings from Continuing Operations (1)(3)	**$ 1,989**	**47%**	$ 1,350	115%	$ 629
($ per Common Share Diluted)					
Net Earnings from Continuing Operations, as reported	**$ 4.72**	**6%**	$ 4.47	183%	$ 1.58
Add: Unrealized mark-to-market accounting loss (after-tax)(2)	**0.25**				
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(0.49)**		(0.90)		(0.04)
Deduct: Future tax recovery due to tax rate reductions	**(0.23)**		(0.75)		(0.05)
Operating Earnings from Continuing Operations (1)(3)	**$ 4.25**	**51%**	$ 2.82	89%	$ 1.49

(1) Operating Earnings from Continuing Operations is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the gain on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively on January 1, 2004. See Note 2 to the Consolidated Financial Statements.

(3) Unrealized (gains)/losses have no impact on cash flow.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

Financial Results from Continuing Operations

($ millions)	**2004**				2003				2002			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 5,704**	**$ 1,320**	**$ 232**	**$ 7,256**	$ 4,447	$ 1,170	$ 180	$ 5,797	$ 2,280	$ 970	$ 76	$ 3,326
Expenses												
Production and mineral taxes	**270**	**41**		**311**	153	11		164	82	23		105
Transportation and selling	**416**	**56**		**472**	360	69		429	210	35		245
Operating	**519**	**285**	**222**	**1,026**	402	300	170	872	290	201	71	562
Operating Cash Flow	**$ 4,499**	**$ 938**	**$ 10**	**$ 5,447**	$ 3,532	$ 790	$ 10	$ 4,332	$ 1,698	$ 711	$ 5	$ 2,414
Depreciation, depletion and amortization				**2,271**				1,900				1,115
Upstream Income				**$ 3,176**				$ 2,432				$ 1,299

2004 vs. 2003

Results from continuing operations reflect a 12 percent increase in sales volumes of 418 MMcfe/d (69,689 BOE/d) for the year ended December 31, 2004 compared with 2003.

Revenues, net of royalties, reflect the increase in natural gas and crude oil benchmark prices (see the Business Environment section of this MD&A) for the year offset by the realized hedging losses. The effect of realized commodity and currency hedging losses for the year ended December 31, 2004 was $669 million, or $0.46 per Mcfe ($2.77 per BOE), compared to $297 million or $0.23 per Mcfe ($1.38 per BOE) for 2003.

North American production and mineral taxes for produced gas increased 76 percent in 2004 compared to 2003 primarily due to increased natural gas prices and volumes in the United States and a higher effective tax rate on production growth in Colorado.

Transportation and selling expenses increased ten percent in 2004 as a result of increased natural gas volumes in the U.S. and Canada and the impact of the change in the average U.S./Canadian dollar exchange rate on Canadian dollar denominated transactions.

For the year ended December 31, 2004, operating expenses were slightly higher at $0.55 per Mcfe ($3.33 per BOE) compared to $0.54 per Mcfe ($3.26 per BOE) for the same period in 2003 due primarily to the increase in the average U.S./Canadian dollar exchange rate during 2004. Excluding the impact of foreign exchange, operating expenses in 2004 would have decreased to $0.51 per Mcfe ($3.10 per BOE) primarily as a result of increased volumes.

DD&A expense increased by $371 million in 2004 compared to 2003 primarily as a result of increased sales volumes and the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. On a North America basis, excluding Other activities, DD&A rates were $1.53 per Mcfe ($9.20 per BOE) for 2004 compared to $1.39 per Mcfe ($8.36 per BOE) in 2003. Increased DD&A rates in 2004 were primarily the result of the increase in the average U.S./Canadian dollar exchange rate and the impact of the acquisition cost of TBI. DD&A rates for the year ended December 31, 2004 exclude impairments of exploration prospects in Ghana, Bahrain and other areas of $23 million, which were recorded in the second and fourth quarters of 2004, respectively.

2003 vs. 2002

The Company s 2003 Upstream revenues, net of royalties, increased $2,471 million, or 74 percent, over 2002 due to the increase in commodity prices, growth in sales volumes and the inclusion of a full year of post merger results. The 23 percent growth in sales volumes from continuing operations of 675 MMcfe/d (112,585 BOE/d) for the year ended December 31, 2003, compared to 2002, reflected increased production in the U.S., the addition of a full year of post merger volumes and the expansion of production from the Company s Steam Assisted Gravity Drainage (SAGD) projects.

Production and mineral tax increases in 2003 were the result of higher prices in the U.S. and a full year of post merger results.

The increased transportation and selling expenses in 2003 were attributable to growth in North American volumes, a full year of post merger results and the effect of the change in the average U.S./Canadian dollar exchange rate on Canadian dollar denominated transportation and selling expenses.

Upstream operating costs increased 55 percent compared to 2002 due to additional production volumes, a full year of post merger results, the change in the average U.S./Canadian dollar exchange rate and its impact on Canadian dollar denominated operating expenses, as well as increased costs for maintenance, workovers, higher fuel and power expense due to higher natural gas prices and an increased proportionate share of costs from SAGD operations.

DD&A expense increased by $785 million in 2003 compared to 2002. On a North America basis, excluding Other activities, DD&A rates were $1.39 per Mcfe ($8.36 per BOE) for 2003 compared to $1.01 per Mcfe ($6.09 per BOE) in 2002. The increased DD&A rate in 2003 reflects increased future development costs related to the proved reserves added for SAGD projects and the U.S., and the effect of the increase in the average U.S./Canadian dollar exchange rate on the Canadian dollar denominated DD&A expense.

Revenue Variances for 2004 compared to 2003 and 2003 compared to 2002
From Continuing Operations

($ millions)		**2004**				2003		
	2003 Revenues, Net of Royalties	**Revenue Variances in: Price[1]**	**Volume**	**2004 Revenues, Net of Royalties**	2002 Revenues, Net of Royalties	Revenue Variances in: Price[1]	Volume	2003 Revenues, Net of Royalties
Produced Gas								
Canada	**$ 3,396**	**$ 271**	**$ 261**	**$ 3,928**	$ 1,882	$ 1,075	$ 439	$ 3,396
United States	**1,051**	**147**	**578**	**1,776**	398	204	449	1,051
Total Produced Gas	**$ 4,447**	**$ 418**	**$ 839**	**$ 5,704**	$ 2,280	$ 1,279	$ 888	$ 4,447
Crude Oil and NGLs								
Canada	**$ 1,078**	**$ 95**	**$ (18)**	**$ 1,155**	$ 914	$ (11)	$ 175	$ 1,078
United States	**92**	**30**	**43**	**165**	56	6	30	92
Total Crude Oil and NGLs	**$ 1,170**	**$ 125**	**$ 25**	**$ 1,320**	$ 970	$ (5)	$ 205	$ 1,170

(1) Includes realized commodity and currency hedging impacts.

The increase in sales volumes accounts for approximately 61 percent of the change in revenues, net of royalties, for 2004 compared with 2003. In the table above, impacts from price changes are reduced as a result of the year over year changes in realized commodity and currency hedge losses mentioned previously.

The Crude Oil and NGLs volume variance in Canada of $(18) million for 2004 compared with 2003 was mainly due to the dispositions of mature conventional producing assets during 2004.

Sales Volumes

	2004	**2004 vs 2003**	2003	2003 vs 2002	2002
Produced Gas *(million cubic feet per day)*	**2,968**	**16%**	2,553	25%	2,048
Crude Oil *(barrels per day)*	**140,379**	**-1%**	142,326	21%	117,218
NGLs *(barrels per day)*	**26,038**	**10%**	23,569	16%	20,259
Continuing Operations *(million cubic feet equivalent per day)* (1)	**3,966**	**12%**	3,548	23%	2,873
Continuing Operations *(barrels of oil equivalent per day)* (2)	**661,084**	**12%**	591,395	23%	478,810
Discontinued Operations					
Ecuador *(barrels per day)*	**77,993**	**68%**	46,521	56%	29,740

United Kingdom *(barrels of oil equivalent per day)* [(2)]	**20,973**	**71%**	12,295	1%	12,195
Syncrude *(barrels per day)*			7,629	-68%	23,540
Discontinued Operations *(million cubic feet equivalent per day)* [(1)]	**594**	**49%**	399	2%	393
Total *(million cubic feet equivalent per day)* [(1)]	**4,560**	**16%**	3,947	21%	3,266
Total *(barrels of oil equivalent per day)* [(2)]	**760,050**	**16%**	657,840	21%	544,285

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

(2) Includes natural gas and liquids (converted to BOE).

In 2004, volumes from continuing operations were higher by 12 percent, or 418 MMcfe/d (69,689 BOE/d), compared to 2003.

Canadian natural gas sales volumes increased approximately seven percent or 134 MMcf/d in 2004. This increase results mostly from successful resource play drilling programs at Greater Sierra and Cutbank Ridge in northeast British Columbia as well as Shallow Gas in southern Alberta; the increased volumes were partially reduced by the disposition of non-core properties during 2004, producing approximately 56 MMcf/d on an annualized basis. Natural gas sales volumes in the United States increased approximately 48 percent or 281 MMcf/d during 2004 primarily due to successful resource play drilling programs in the Piceance and Fort Worth basins and incremental production of 161 MMcf/d from the TBI acquisition.

In 2004, liquids sales volumes were relatively unchanged when compared to 2003. The impacts of continued development at Foster Creek, successful drilling programs at Suffield and Weyburn, and positive response from the waterflood program at Pelican Lake were offset by the Petrovera and other non-core dispositions in the first and third quarters of 2004, respectively, which reduced production by 19,800 bbls/d on an annualized basis.

Highlights:

Greater Sierra
Natural gas production averaged 230 MMcf/d, an increase of 61 percent (or 87 MMcf/d) in 2004 mainly due to the success of the 2003/2004 drilling program. In 2004, 187 net wells were drilled.

Cutbank Ridge
2004 was the first full year of operations. Natural gas production averaged 40 MMcf/d and exited the year at 47 MMcf/d. In 2004, 50 net wells were drilled.

Coalbed Methane
Natural gas production in 2004 exited the year at 30 MMcf/d and averaged 17 MMcf/d, up from 4 MMcf/d in 2003. During the year, 577 net wells were drilled.

Shallow Gas
During 2004, natural gas production increased 17 percent to 592 MMcf/d with 1,552 net wells drilled.

Piceance
Natural gas production averaged 261 MMcf/d in 2004, an increase of 73 percent or 110 MMcf/d compared to 2003. This increase is the result of a successful drilling program (250 net wells) and the TBI acquisition.

Fort Worth
EnCana acquired assets in the Fort Worth Basin in 2003 with the Savannah Energy Inc. acquisition and added to those assets as a result of a December 2004 property acquisition. Production averaged 27 MMcf/d in 2004.

East Texas
East Texas, which produced 50 MMcf/d during 2004, was acquired as part of the TBI acquisition. During 2004, 50 net wells were drilled.

Foster Creek
Completion of the first phase of facility expansion in the fall of 2003 resulted in a 32 percent increase in 2004 crude oil production to 28,800 bbls/d.

Pelican Lake
Average crude oil production in 2004 increased 19 percent to 18,900 bbls/d due to the response of the waterflood program which began in the last half of 2004.

Per Unit Results **Produced Gas** *($ per thousand cubic feet)*

	Canada					**United States**				
	2004	**2004 vs 2003**	2003	2003 vs 2002	2002	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
Price[(1)]	**$ 5.34**	**10%**	$ 4.87	70%	$ 2.86	**$ 5.79**	**19%**	$ 4.88	65%	$ 2.96
Expenses										
Production and mineral taxes	**0.08**	**14%**	0.07	-13%	0.08	**0.65**	**38%**	0.47	74%	0.27
	0.39	**3%**	0.38	58%	0.24	**0.31**	**-23%**	0.40	-15%	0.47

Transportation and selling[2]										
Operating	**0.52**	**8%**	0.48	17%	0.41	**0.37**	**32%**	0.28		0.28
Netback	**$ 4.35**		$ 3.94		$ 2.13	**$ 4.46**		$ 3.73		$ 1.94
Gas Sales Volumes *(MMcf per day)*	**2,099**	**7%**	1,965	15%	1,711	**869**	**48%**	588	74%	337

(1) Excludes realized commodity and currency hedge activities.

(2) U.S. per unit transportation and selling costs in 2004 exclude a one-time payment of $21 million made to terminate a long-term physical delivery contract.

Benchmark natural gas NYMEX prices were higher by 14 percent compared with 2003, however this increase has been partially offset by increased natural gas price differentials in Canada. For the year ended December 31, 2004, realized commodity and currency hedging losses on natural gas were approximately $238 million, or $0.22 per Mcf compared to a loss of approximately $91 million, or $0.10 per Mcf in 2003. Certain of these hedges were put in place to secure the economics of the TBI acquisition.

Per unit production and mineral taxes in the U.S. for the year ended December 31, 2004 compared to 2003 increased 38 percent or $0.18 per Mcf due to a combination of higher gas prices and a higher effective tax rate on the significant production growth in Colorado.

Natural gas per unit transportation and selling costs for the U.S. have decreased 23 percent or $0.09 per Mcf for the year ended December 31, 2004 compared to 2003, primarily as a result of the TBI acquisition where a majority of the production is sold at the wellhead and does not incur transportation charges.

Canadian natural gas per unit operating expenses for 2004 were eight percent or $0.04 per Mcf higher compared to 2003 primarily due to the higher U.S./Canadian exchange rates. Increases in the U.S. per unit natural gas operating expenses of 32 percent or $0.09 per Mcf for the year ended December 31, 2004 compared to 2003 were a result of higher operating expenses from the TBI properties, incremental operating costs associated with waste water disposal in Colorado and other non-recurring charges related to the prior year.

Average realized prices for natural gas in the U.S. and Canada for 2003 increased by approximately 65 percent and 70 percent respectively, over 2002 due to concerns about overall North American storage inventory levels and a lack of confidence concerning prospects for North American supply growth. Realized commodity and currency hedging gains in 2002 for natural gas were $66 million, or $0.09 per Mcf.

Per unit production and mineral tax expense in the U.S. was $0.20 per Mcf higher in 2003 than 2002 due to higher natural gas prices.

For Canadian produced gas operations, per unit transportation and selling costs were higher in 2003 compared to 2002 by $0.14 per Mcf due to an increased proportion of sales transported to more distant markets and the change in the U.S./Canadian dollar exchange rate.

Per unit operating expenses for Canadian produced gas were higher in 2003 compared to 2002 by $0.07 per Mcf as a result of increased maintenance, workovers, the effect of the change in the U.S./Canadian dollar exchange rate and production from higher operating cost areas.

Per Unit Results Crude Oil *($ per barrel)*

	North America				
	2004	**2004 vs 2003**	2003	2003 vs 2002	2002
Price[1]	**$ 27.92**	**25%**	$ 22.29	11%	$ 20.08
Expenses					
Production and mineral taxes	**0.41**	**356%**	0.09	-79%	0.43
Transportation and selling	**1.06**	**-19%**	1.31	60%	0.82
Operating	**5.53**	**-5%**	5.80	24%	4.69
Netback	**$ 20.92**		$ 15.09		$ 14.14
Crude Oil Sales Volumes *(bbls per day)*	**140,379**	**-1%**	142,326	21%	117,218

(1) Excludes realized commodity and currency hedge activities.

Increases in the average crude oil price in 2004, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 34 percent in 2004 compared to 2003. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 60 percent) and a higher proportionate share of heavier blend oils in the product mix. Realized commodity and currency hedging losses on crude oil were approximately $431 million, or $7.08 per bbl of liquids in 2004 compared to a loss of approximately $206 million, or $3.41 per bbl of liquids in 2003.

North American per unit production and mineral taxes increased in 2004 primarily as a result of mineral tax amendments related to prior years that were recorded in the third quarter of 2003. Higher freehold mineral tax and Saskatchewan surtax in the Weyburn area resulted from higher prices and increased production.

The 2004 per unit crude oil transportation and selling expenses in North America have decreased $0.25 per bbl mainly due to an adjustment in oil transportation rates.

North American crude oil per unit operating costs for 2004 have decreased $0.27 per bbl compared to 2003 mainly due to the sale of Petrovera, which had higher operating costs relative to other properties. This reduction was partially offset by the effect of increased U.S./Canadian exchange rates and higher fuel gas costs for the SAGD projects.

Average realized crude oil prices in 2003 increased approximately 11 percent over 2002 as a result of concerns over tensions in the Middle East combined with strong Asian demand and OPEC s management of its production quotas. Realized commodity and currency hedging losses in 2002 on crude oil were $32 million, or $0.64 per bbl of liquids.

Per unit transportation and selling costs were higher by $0.49 per bbl over 2002 as a result of increased heavy crude oil volumes which attract a 20 percent premium transportation charge over light crude oil combined with annual tariff increases.

The increase in per unit operating expenses of $1.11 per bbl for 2003 compared to 2002 is attributable to the increase in the U.S./Canadian dollar exchange rate, higher maintenance costs and increased production weighting of heavy oil volumes from SAGD projects, which have higher operating expenses, combined with higher fuel and electricity costs resulting from the rise in natural gas prices.

Per Unit Results NGLs[1] *($ per barrel)*

	Canada					United States				
	2004	**2004 vs 2003**	2003	2003 vs 2002	2002	**2004**	**2004 vs 2003**	2003	2003 vs 2002	2002
Price	**$ 31.43**	**30%**	$ 24.26	38%	$ 17.55	**$ 35.43**	**31%**	$ 26.97	14%	$ 23.75
Expenses										
Production and mineral taxes						**3.82**	**88%**	2.03	99%	1.02
Transportation and selling	**0.41**	**141%**	0.17							
Netback	**$ 31.02**		$ 24.09		$ 17.55	**$ 31.61**		$ 24.94		$ 22.73
NGLs Sales Volumes *(bbls per day)*	**13,452**	**-6%**	14,278	3%	13,852	**12,586**	**35%**	9,291	45%	6,407

(1) NGLs results include Condensate.

NGLs realized price changes generally correlate with changes in WTI oil prices. The strong WTI oil price in 2004 positively impacted NGLs prices.

U.S. per unit production and mineral taxes for the year ended December 31, 2004 compared to 2003 increased by 88 percent or $1.79 per bbl. Higher NGLs prices in 2004 and increased production growth in Colorado, which has a higher effective production tax rate, were the key reasons for this increase.

Per unit transportation and selling costs for NGLs in Canada increased by 141 percent or $0.24 per bbl in 2004 compared to 2003 as the Company incurred a full year of trucking charges for volumes in northeast British Columbia that came onstream in the fall of 2003.

MIDSTREAM & MARKET OPTIMIZATION OPERATIONS

Financial Results

($ millions)	**2004**			2003			2002		
	Midstream	**Market Optimization**	**Total**	Midstream	Market Optimization	Total	Midstream	Market Optimization	Total
Revenues	**$ 1,450**	**$ 3,299**	**$ 4,749**	$ 1,084	$ 2,803	$ 3,887	$ 440	$ 2,154	$ 2,594
Expenses									
Transportation and selling		**27**	**27**		55	55		87	87

Operating	**279**	**46**	**325**	261	63	324	174	13	187
Purchased product	**1,071**	**3,205**	**4,276**	762	2,693	3,455	169	2,031	2,200
Operating Cash Flow	**$ 100**	**$ 21**	**$ 121**	$ 61	$ (8)	$ 53	$ 97	$ 23	$ 120
Depreciation, depletion and amortization			**70**			48			36
Segment Income			**$ 51**			$ 5			$ 84

Revenues and purchased product expense in Midstream & Market Optimization operations increased in 2004 compared to 2003 due primarily to increases in commodity prices. Operating cash flow increased $68 million in 2004 to $121 million as a result of improved margins from natural gas liquids processing and gas storage optimization activities. Decreases in transportation and selling costs in 2004 compared to 2003 are primarily due to the reallocation of natural gas downstream transportation costs to the Upstream segment. Operating expenses in 2003 included a $20 million settlement with the U.S. Commodity Futures Trading Commission as described in the Contractual Obligations and Contingencies section of this MD&A.

The increase in 2004 DD&A is primarily due to a write down in the value of the Company s equity investment interest in the Trasandino Pipeline in Argentina and Chile of approximately $35 million.

CORPORATE

($ millions)	**2004**	2003	2002
Revenues	**$ (195)**	$ 2	$ 8
Expenses			
Operating	**(1)**		
Depreciation, depletion and amortization	**61**	41	35
Segment Income	**$ (255)**	$ (39)	$ (27)
Administrative	**197**	173	118
Interest, net	**397**	283	286
Accretion of asset retirement obligation	**22**	17	13
Foreign exchange gain	**(417)**	(598)	(11)
Stock-based compensation	**17**	18	
Gain on dispositions	**(113)**	(1)	(33)
Income tax expense	**658**	364	317

Corporate revenues in 2004 include approximately $197 million in unrealized mark-to-market losses related to financial and commodity contracts. Other mark-to-market gains ($7 million) on derivative financial instruments related to interest and electricity consumption are recorded in interest, net and operating expenses respectively.

DD&A includes provisions for corporate assets such as computer equipment, office furniture and leasehold improvements. The increase in expense on a year-over-year basis is the result of higher capital spending in prior periods on corporate capital items and the impact of the change in the U.S./Canadian dollar exchange rate.

Administrative expenses increased 14 percent in 2004. The increase reflects the effect of the change in the U.S./Canadian dollar exchange rate and increased long-term compensation expenses. Administrative costs were approximately $0.12 per Mcfe in both 2004 and 2003.

The higher interest expense resulted primarily from the higher average outstanding debt level during the year as a result of the TBI acquisition in the second quarter of 2004. EnCana s weighted average interest rate on outstanding debt was marginally lower in 2004 than it was in 2003 and partially mitigated the effect of higher debt levels.

The majority of the foreign exchange gain of $417 million in 2004 resulted from the change in the U.S./Canadian dollar exchange rate during 2004 applied to U.S. dollar denominated debt issued in Canada as discussed previously in this MD&A. Under Canadian GAAP, the Company is required to translate long-term debt issued in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

During 2004, EnCana sold certain corporate investments and recorded gains of $113 million on these sales.

The effective tax rate for 2004 was 23 percent compared to 15 percent for 2003 and 32 percent for 2002. Further information regarding EnCana s effective tax rate can be found in Note 9 to the Consolidated Financial Statements. EnCana s effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing permanent differences that are excluded from the earnings subject to tax. There are a variety of items of this type, including:

- The effects of asset dispositions where the tax values of the assets sold differ from their accounting value.

- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations.

- The non-taxable half of Canadian capital gains (losses).

- Items such as resource allowance and non-deductible crown payments where the income tax treatment is different from the accounting treatment.

The 2004 effective tax rate reflects a reduction of $109 million in future income taxes resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent and Alberta s retention of the resource allowance and non-deductible crown royalties regime until 2007. In 2003, the effective tax rate reflected a $359 million reduction in future income taxes resulting from the reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the Canadian federal resource allowance deduction.

Current income tax expense for the year ended 2004 was $567 million compared to $(113) million in 2003 and $(66) million in 2002. As expected, current taxes increased significantly in 2004; 2003 and 2002 were abnormally low as a result of the effects of the merger with Alberta Energy Company Ltd.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

CAPITAL EXPENDITURES

Capital Summary

	2004	2003	2002[1]
Upstream	**$ 4,343**	$ 3,845	$ 1,932
Midstream & Market Optimization	**64**	223	47
Corporate	**46**	57	43
Core Capital Expenditures	**$ 4,453**	$ 4,125	$ 2,022
Acquisitions	**2,986**	593	748
Dispositions	**(1,817)**	(301)	(423)
Discontinued Operations	**(1,416)**	(995)	397
Net Capital	**$ 4,206**	$ 3,422	$ 2,744

(1) 2002 amounts include post merger capital only.

The Company s core capital expenditures increased approximately $0.3 billion to $4.5 billion in 2004. The increase in Upstream core capital expenditures in 2004 compared to 2003 was primarily as a result of continued development of EnCana s United States resource play properties. Net capital expenditures increased approximately $0.8 billion compared to 2003 as a result of the TBI acquisition, increased drilling in the U.S., higher cost wells drilled both in Canada and the U.S., and the impact of the higher U.S./Canadian dollar exchange rate partially offset by the sale of the U.K. operations and non-core asset dispositions. The Company s capital investment was funded by cash flow in excess of amounts paid for purchases of Common Shares under the Normal Course Issuer Bid, proceeds received on dispositions of non-core assets and debt.

UPSTREAM CAPITAL EXPENDITURES

The increase in Upstream capital expenditures in 2004 compared to 2003 reflects increased drilling and development activities in the U.S. and the impact of the increased average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. On an annual basis the change in the average U.S./Canadian dollar exchange rate resulted in an increase on Canadian dollar denominated core capital expenditures of approximately $230 million. Capital spending during 2004 was primarily focused on North American resource play properties. Natural gas capital expenditures were primarily focused on continued development of the Company s key resource plays in Greater Sierra, Cutbank Ridge and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2004 was concentrated at Foster Creek, Pelican Lake and Suffield in Alberta and Weyburn in Saskatchewan. The Company drilled 4,923 net wells in 2004 compared to 5,581 net wells in 2003.

Canadian East Coast

In 2004, the Company participated in two deep water tests at Weymouth and Crimson. Both of these wells were plugged and abandoned. As of December 31, 2004, the Company s investment in its East Coast assets, including Deep Panuke, is recorded at approximately $371 million. Until assessments of the economics of the Panuke project are complete, the timing of any potential start of production and amount of additional costs which may be incurred are not determinable.

Gulf of Mexico

During 2004, the Company s operating partner completed a well test at the Tahiti oilfield which is located 304 kilometres southwest of New Orleans. As of December 31, 2004, the Company had invested approximately $394 million in the Gulf of Mexico, including Tahiti. The field is expected to begin production in 2008. The Company has announced that it intends to sell its interests in the Gulf of Mexico.

Reserves

Each year, EnCana engages independent qualified reserve evaluators to prepare reports on 100 percent of the Corporation s oil and natural gas reserves. The Company has a Reserves Committee of independent board members which reviews the qualifications and appointment of the independent qualified reserve evaluators. The Committee also reviews the procedure for providing information to the evaluators. EnCana s disclosure of reserves data is covered by NI 51-101 as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) reserve reporting requirements, in 2003. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation - in this case December 31, 2004.

EnCana s proved natural gas reserves as at December 31, 2004, on an SEC constant price basis, totalled 10,460 Bcf. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 2,431 Bcf. Downward revisions of 252 Bcf in the United States were largely the result of reduced reserve estimates per well in the northern and southern Rockies. Net acquisitions were dominated by the purchase of TBI in May 2004.

The Company s proved crude oil and natural gas liquids reserves as at December 31, 2004, on an SEC constant price basis, totalled 501 MMbbls. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 163 MMbbls. Downward revisions in Canada were dominated by a 363 MMbbls adjustment at Foster Creek necessitated by reliance on year-end prices for bitumen determined in accordance with SEC and FASB requirements. If EnCana were applying the approach set out by the Canadian Securities Administrators in their Staff Notice 51-315, dated January 20, 2005, namely the use of the average price differential for the preceding 12 months, it is expected that no negative revisions to the company s proved bitumen reserves would occur. Divestitures were dominated by the sale of all of EnCana s interests in the U.K. central North Sea and non-core interests in Western Canada.

Proved Reserves by Country

Constant Prices After Royalties	Natural Gas					Crude Oil and NGLs[1]				
As at December 31	**2004**	**2004 vs. 2003**	2003	2003 vs. 2002	2002	**2004**	**2004 vs. 2003[2]**	2003	2003 vs. 2002	2002
	(billions of cubic feet)					*(millions of barrels)*				
Canada	**5,824**	**11%**	5,256	4%	5,073	**267**	**-58%**	629	16%	542
United States	**4,636**	**48%**	3,129	22%	2,573	**91**	**117%**	42	2%	41
Ecuador						**143**	**-12%**	162	4%	156
United Kingdom		**-100%**	26	30%	20		**-100%**	124	28%	97
Total	**10,460**	**24%**	8,411	10%	7,666	**501**	**-48%**	957	14%	836

(1) NGLs include condensate.

(2) Year-end 2004 Canadian Crude Oil and NGLs reserves were essentially unchanged from the previous year, prior to the bitumen revisions caused by an anomalously low December 31, 2004 field price.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties	Natural Gas				Crude Oil and NGLs[1]				
As at December 31, 2004	*(billions of cubic feet)*				*(millions of barrels)*				
	Canada	**USA**	**UK**	**Total**	**Canada**	**USA**	**Ecuador**	**UK**	**Total**
Beginning of year	5,256	3,129	26	8,411	629	42	162	124	957
Revisions and improved recovery	67	(252)		(185)	32		(12)		20
Extensions and discoveries	1,422	1,009		2,431	94	48	21		163
Acquisitions	65	1,150	10	1,225	29	12		10	51
Divestitures	(215)	(82)	(25)	(322)	(97)	(6)		(128)	(231)
Production	(771)	(318)	(11)	(1,100)	(57)	(5)	(28)	(6)	(96)
End of year before bitumen revisions	5,824	4,636		10,460	630 [3]	91	143		864
Revisions due to bitumen price[2]					(363)				(363)
End of year	5,824	4,636		10,460	267	91	143		501

(1) NGLs include condensate.

(2) As a result of using year-end price.

(3) Year-end 2004 Canadian Crude Oil and NGLs reserves were essentially unchanged from the previous year, prior to the bitumen revisions caused by an anomalously low December 31, 2004 field price.

MIDSTREAM & MARKET OPTIMIZATION CAPITAL EXPENDITURES

Expenditures in 2004 related primarily to ongoing improvements to midstream facilities.

CORPORATE CAPITAL EXPENDITURES

Corporate capital expenditures relate primarily to spending on business information systems, leasehold improvements and furniture and office equipment.

DISCONTINUED OPERATIONS

United Kingdom and Ecuador assets are presented as discontinued operations in the Consolidated Financial Statements. EnCana s net earnings from discontinued operations are $1,302 million and include a gain of $1,364 million on the discontinuance of U.K. operations, realized financial and commodity hedge losses of $358 million and unrealized financial and commodity hedge losses of $71 million. Summary information is presented below. Additional information concerning EnCana s discontinued operations can be found in Note 5 to EnCana s Consolidated Financial Statements.

UNITED KINGDOM

	2004	2003	2002
Sales volumes			
Produced Gas *(million cubic feet per day)*	**30**	13	10
Crude Oil *(barrels per day)*	**14,128**	9,231	9,733
NGLs *(barrels per day)*	**1,845**	897	795
Total *(million cubic feet equivalent per day)*	**126**	74	73
($ millions)			
Net earnings (loss) from discontinued operations	**$ 1,338**	$ (7)	$ 24
Capital Investment	**488**	223	82

In December 2004, a subsidiary of the Company completed the sale of its U.K. central North Sea assets, production and prospects for net cash consideration of approximately $2.1 billion, resulting in a gain on sale of approximately $1.4 billion.

Liquids sales volumes in 2004 increased to 15,973 bbls/d from 10,128 bbls/d in 2003 primarily as a result of the acquisitions of additional interests in the Scott and Telford fields in October 2003 and February 2004. Higher transportation and selling expenses in 2004 compared to 2003 of $20 million were primarily due to higher product volumes. Operating expenses increased approximately $18 million in 2004 due to a platform turnaround, higher maintenance costs and higher volumes. Increased DD&A expense in 2004 of $44 million over 2003 was primarily due to increased volumes offset by a decrease in the DD&A rate.

ECUADOR

	2004	2003	2002
Sales volumes			
Crude Oil *(barrels per day)*	**77,993**	46,521	29,740
($ millions)			
Net (loss) earnings from discontinued operations	**$ (33)**	$ 32	$ 45
Capital Investment	**240**	367	169

At December 31, 2004, EnCana has decided to sell its Ecuador operations, and accordingly the Ecuador operations have been accounted for as discontinued operations.

Sales volumes in 2004 increased 68 percent to average approximately 78,000 bbls/d. The increased sales volumes are primarily due to the combination of available capacity on the OCP pipeline in Ecuador and increased production from Block 15.

Production and mineral taxes were $36 million higher in 2004 compared to 2003 as a result of higher realized prices and volumes on the Tarapoa block. The Company is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price. Operating costs were $42 million higher in 2004 compared to 2003 due to higher workover costs and increased fuel and diesel costs and higher maintenance and personnel costs on Block 15. DD&A expense increased $104 million compared to 2003 as a result of higher crude oil volumes.

Crude oil sales volumes increased 56 percent in 2003, compared to 2002, due to the inclusion of a full year of post merger volumes and the removal of transportation capacity constraints as a result of the commencement of shipments on the OCP pipeline in September 2003. Higher production and mineral taxes in 2003, compared to 2002 resulted from increased production from the Tarapoa block and higher realized prices from Tarapoa volumes. Transportation and selling costs were higher in 2003 and reflect the higher tariff on OCP pipeline compared to the SOTE pipeline system. Operating expenses and DD&A increased in 2003 compared to 2002 primarily due to higher crude oil volumes.

Contingency information concerning Ecuador discontinued operations is included in Note 5 to EnCana s Consolidated Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

EnCana s cash flow from continuing operations was $4,605 million in 2004, up $470 million compared to 2003. The increase in cash flow was primarily due to increased revenues from the growth in sales volumes and higher commodity prices offset by higher realized commodity and currency hedging losses, an increase in the current tax provision and an increase in the U.S./Canadian dollar exchange rate.

During 2004, long-term debt plus the current portion of long-term debt increased $1,555 million. This increase resulted from the acquisition of TBI and capital spending offset by proceeds of dispositions and increased cash flow during 2004, including proceeds of $2.1 billion received from the sale of the U.K. assets on December 1, which were used to repay bank and other indebtedness. EnCana s net debt adjusted for working capital was $7,184 million as at December 31, 2004 compared with $5,544 million at December 31, 2003. Working capital was $558 million and included unrealized losses on mark-to-market accounting on derivatives of $95 million and a current tax payable of $359 million. This compares to a working capital of $544 million as at December 31, 2003. Cash flow together with proceeds from dispositions were used for the purchase of shares under the Company s Normal Course Issuer Bid and capital expenditures.

Net debt to capitalization at the end of 2004 is 33 percent, unchanged from 2003. Management calculates this ratio for internal purposes to steward the Company s overall debt position as a measure of a company s financial strength.

EnCana s long term credit ratings were confirmed by Standard & Poor s and Dominion Bond Rating Services credit rating agencies in October 2004. Standard & Poor s has affirmed an A with a Negative Outlook and Dominion Bond Rating Services has affirmed an A(low) with a Stable Trend . Moody s long-term credit rating for EnCana remains at Baa2 Stable . The agencies are expected to continue to monitor the Company s operating and financial performance through the first quarter of 2005.

On March 23, 2004 the Company redeemed all of its Coupon Reset Subordinated Term Securities, Series A (Term Securities) which had an aggregate principal amount of approximately C$126 million. The redemption price of the Term Securities was the principal amount plus accrued and unpaid interest to the redemption date.

In March 2004, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp. (EHFC), filed a shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. Debt securities issued under this shelf prospectus are unconditionally guaranteed by EnCana Corporation. On May 13, 2004 EHFC completed a $1.0 billion unsecured public debt offering in the U.S. The notes, which are due in 2014, bear interest at 5.8 percent. The net proceeds of the offering were used to fund a portion of the acquisition of TBI.

After EnCana s acquisition of TBI, TBI and a subsidiary made a consent tender offer for $225 million for their 7.25 percent Senior Subordinated Notes. A total of 98.9 percent of the notes were tendered for a total cost of approximately $258 million. Subsequently, in December 2004 and January 2005, the balance of the notes were purchased for a total cost of approximately $2.9 million.

On August 4, 2004, EnCana completed a public offering in the United States for $250 million notes due in 2009 at 4.60 percent and $750 million notes due in 2034 at 6.50 percent. The proceeds from these issues were used primarily to repay existing bank and commercial paper indebtedness.

On August 9, 2004, EnCana redeemed all of its 8.50 percent Unsecured Junior Subordinated Debentures due 2048, which had an aggregate principal amount of C$200 million, at par plus accrued interest. On September 30, 2004, EnCana redeemed all of its 9.50 percent Preferred Securities due 2048, which had an aggregate principal amount of $150 million, at par.

In September 2004, EnCana filed a multi-jurisdictional shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. This shelf prospectus replaced EnCana s previous $2 billion U.S. debt shelf prospectus which expired on September 22, 2004. No amounts have been issued under the new shelf prospectus.

In October 2004, the Company completed the refinancing of its general corporate bank credit facilities. Under this refinancing, EnCana s core bank facilities were increased in size from C$4.0 billion to C$4.5 billion, and the term of the two tranches were extended to three and five years. In December, the bank credit facilities of a wholly owned U.S. subsidiary were increased from $300 million to $600 million, all in a five year term.

As at December 31, 2004, the Company had available unused committed bank credit facilities in the amount of $2.4 billion.

In October 2004, EnCana received approval from the Toronto Stock Exchange (TSX) to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the Bid). Under the Bid, EnCana was entitled to purchase for cancellation up to five percent of its Common Shares issued and outstanding on October 22, 2004 over a 12-month period ending October 28, 2005. As of December 31, 2004, EnCana had purchased for cancellation approximately 14.8 million of its shares under the Bid. In February 2005, EnCana received approval from the TSX to amend the Bid. Under the amended Bid, EnCana is entitled to purchase up to 46.1 million Common Shares (ten percent of the public float on October 22, 2004). Purchases may be made through the facilities of the TSX and the New York Stock Exchange, in accordance with the policies and rules of each exchange.

During 2004, EnCana purchased for cancellation a total of approximately 20 million shares for a total of approximately $1 billion under the terms of its Normal Course Issuer Bids.

Normal Course Issuer Bid

(millions)	Share Purchases				Number of shares entitled to purchase
	2004	2003	2002	Total	
Bid expiring October 2003		20.2		20.2	23.8
Bid expiring October 2004	5.5	3.6		9.1	23.2
Bid expiring October 2005	14.8			14.8	46.1
	20.3	23.8		44.1	

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. The reduction of 10.3 million Common Shares outstanding from the end of 2003 to the end of 2004 (18.3 million from the end of 2002 to the end of 2003) results from the repurchase of 20.3 million shares in 2004 (23.8 million in 2003) under the Normal Course Issuer Bid and the issuance of 9.7 million Common Shares (5.5 million in 2003) under Option plans.

Share Capital Common Shares

($ millions)	2004	2003	2002
Common shares outstanding, end of year	450.3	460.6	478.9
Weighted average common shares outstanding diluted	468.0	479.7	422.6

As at January 31, 2005, there were 446.5 million Common Shares outstanding. There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. These plans and their terms and outstanding balances are disclosed in detail in Note 15 to the Consolidated Financial Statements.

Effective February 22, 2005 the Company s Board of Directors resolved to recommend the split of the Corporation s outstanding Common Shares on a two-for-one basis (Share Split). EnCana s shareholders will be asked to approve the Share Split at its annual and special meeting to be held on April 27, 2005. In addition to shareholder approval, the Share Split is subject to the receipt of all required regulatory approvals. If approved by shareholders, and subject to regulatory approvals, each shareholder will receive one additional common share for each common share he or she holds on the record date for the Share Split of May 12, 2005. Pursuant to the rules of the Toronto Stock Exchange, EnCana s common shares will commence trading on a subdivided basis at the opening of business on May 10, 2005, which is the second trading day preceding the record date. Also on May 10, 2005, EnCana s common shares listed on the New York Stock Exchange (NYSE) will commence trading with rights entitling holders to an additional common share for each common share held upon the commencement of trading of the common shares on a subdivided basis on the NYSE. The trading of the common shares on a subdivided basis on the NYSE will occur one day after the delivery of share certificates to registered holders of EnCana s common shares. It is anticipated that share certificates representing the additional common shares resulting from the Share Split will be delivered to registered common shareholders on or about May 20, 2005.

The Compensation Committee of the Board of Directors, in 2003, approved a long-term incentive strategy for employees throughout EnCana which includes a significantly reduced level of stock option grants to be supplemented by grants of Performance Share Units (PSUs). In 2004, the Board of Directors approved a modification to the PSU plan that provides a reduced payout if relative ranking is below median. This change applies to units granted in both 2004 and 2005. PSUs will not result in the issue of new Common Shares by the Company. Stock options granted in 2004 have an associated Tandem Share Appreciation Right (TSAR) and employees may elect to exercise either the stock option or the associated TSAR. TSAR exercises will result in either cash payments by the Company or issuance of Common Shares.

As previously detailed in the Liquidity and Capital Resources section of this MD&A, the Company obtained regulatory approval under Canadian securities laws to purchase Common Shares under three consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 28, 2005. Under the terms of the bids, the Company repurchased for cancellation approximately 20 million Common Shares during 2004, and as of

December 31, 2004, was entitled to purchase for cancellation an additional 8 million Common Shares. On February 4, 2005, EnCana received approval from the TSX to amend the Bid and increase the number of Common Shares available for purchase from five percent of the issued and outstanding shares on October 22, 2004 to ten percent of the public float. Under the amended Bid, EnCana is entitled to purchase for cancellation up to approximately 46.1 million Common Shares. To the date of the amendment, EnCana had purchased approximately 21.2 million Common Shares under the Bid, leaving approximately 24.9 million Common Shares available for purchase through the expiry of the Bid on October 28, 2005. Shareholders may obtain a copy of the Bid documents without charge at www.sedar.com or by contacting investor.relations@encana.com

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. The following table summarizes the Company s contractual obligations at December 31, 2004:

	Expected Payment Date				
($ millions)	2005	2006 to 2007	2008 to 2009	2010+	Total
Long-Term Debt	$ 188	$ 487	$ 841	$ 4,434	$ 5,950
Asset Retirement Obligations	2	13		3,680	3,695
Operating Leases[2]	42	84	65	152	343
Pipeline Transportation	297	499	402	1,010	2,208
Capital Commitments	190	63	4	38	295
Purchase of Goods and Services	121	37	12	5	175
Product Purchases	171	57	48	134	410
	1,011	1,240	1,372	9,453	13,076
Discontinued operations [3]	99	185	189	876	1,349
Total Contractual Obligations[1]	$ 1,110	$ 1,425	$ 1,561	$ 10,329	$ 14,425

(1) In addition, the Company has made commitments related to its risk management program. See Note 17 to the Consolidated Financial Statements. The Company also has an obligation to fund its Pension Plan and Other Post Retirement Benefits as disclosed in Note 16 to the Consolidated Financial Statements.

(2) Related to office space.

(3) Primarily related to long term transportation commitments.

In addition to the long-term debt payments outlined above, at December 31, 2004 the Company had $1,914 million outstanding related to Banker s Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company s long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the contractual obligations outlined above is included in Note 19 to the Consolidated Financial Statements.

As at December 31, 2004, EnCana had remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 167 Bcf at a weighted average price of $3.71 per Mcf. At December 31, 2004, these transactions had an unrealized loss of $157 million.

Commitments and Contingencies associated with Ecuador discontinued operations are included in Note 5 to EnCana s Consolidated Financial Statements.

Variable Interest Entities (VIE)

In December 2004, an EnCana subsidiary finalized the purchase of certain oil and gas properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, which holds the assets in trust for the Company. EnCana operates the properties, receives all the revenue and pays all of the expenses associated with these properties. The assets will be transferred to EnCana at the earliest of June 15, 2005 or upon the disposition of certain natural gas and crude oil properties by EnCana. EnCana has determined that this relationship represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has included these properties in its consolidated results from the date of acquisition. This subsidiary will not hold title to these properties until an exchange transaction has been completed.

Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

Leases

As a normal course of business, the Company leases office space for personnel who support field operations and corporate purposes.

Legal Proceedings Related to Discontinued Merchant Energy Operations

In July 2003, the Company s indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), concluded a settlement with the U.S. Commodity Futures Trading Commission (CFTC) of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD s now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with AEC in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC s order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. A motion by the Company and WD to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws.

Most of the California lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and all of the New York lawsuits were consolidated in New York District Court by the plaintiff s application. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving WD and several other companies unrelated to the Company as the remaining defendants. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company s financial position, or whether there will be other proceedings arising out of these allegations.

ACCOUNTING POLICIES AND ESTIMATES

CHANGES IN ACCOUNTING PRINCIPLES AND PRACTICES

Hedging Relationships
On January 1, 2004, the Company adopted the amendments made to the Canadian Institute of Chartered Accountants (CICA) Accounting Guideline AcG-13 Hedging Relationships . Derivative instruments outstanding at January 1, 2004 that did not qualify as a hedge under AcG-13 or were not designated as a hedge, were recorded using the mark-to-market accounting method whereby their fair value was recorded on the Consolidated Balance Sheet. The impact on the Company s Consolidated Financial Statements at January 1, 2004 was an increase in assets of $145 million, an increase in liabilities of $380 million and a net deferred loss of $235 million. These amounts are taken into net earnings as the contracts expire. At December 31, 2004, there remains a net gain of $72 million to be recognized as described in Note 2 to the Consolidated Financial Statements.

Consolidation of Variable Interest Entities
On November 1, 2004, the Company retroactively adopted the new CICA Accounting Guideline AcG-15 Consolidation of Variable Interest Entities . AcG-15 defines a variable interest entity (VIE) as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE s expected gains or losses, the primary beneficiary, to consolidate the VIE.

The retroactive adoption of AcG-15 had no effect on EnCana s prior Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES
Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion

outlines the accounting policies and practices that are critical to determining EnCana s financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs directly associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of EnCana s oil and gas reserves are evaluated and reported on by independent qualified reserve evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired in the merger with AEC and the acquisition of TBI, is assessed by the Company for impairment at least annually. Goodwill was allocated to the business segments at the time of the above transactions based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

Derivative Financial Instruments

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

The Company enters into financial transactions to reduce its exposure to price fluctuations with respect to a portion of its oil and gas production to help achieve returns on new projects, targeted returns on new investments and steady funding of growth projects or to mitigate market price risk associated with cash flows expected to be generated from budgeted capital programs. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions.

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

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

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

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives are recognized in natural gas and crude oil revenues as the related production occurs. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators.

In 2004, the Company elected not to designate any of its current price risk management activities as accounting hedges under AcG-13 and accordingly, accounts for all derivatives using the mark-to-market accounting method.

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

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

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

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension costs are a component of compensation costs.

Performance Share Units (PSUs)
The PSU plans provide for a range of payouts, based on EnCana s performance relative to certain peers.

The Company expenses the cost of PSUs based on expected payouts, however, the amounts to be paid, if any, may vary from the current estimate.

RISK MANAGEMENT

EnCana s results are affected by

- financial risks (including commodity price, foreign exchange, interest rate and credit risks)
- operational risks
- environmental, health, safety and security risks
- reputational risks

FINANCIAL RISKS
The Company partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk, the Company has entered into various financial instrument agreements. The Company s policy is not to use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of December 31, 2004, are disclosed in Note 17 to the Consolidated Financial Statements.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Commodity Price
To partially mitigate the natural gas commodity price risk, the Company entered into swaps which fix the AECO and NYMEX prices and collars and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized loss of $9 million.

The Company has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company s proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $43 million.

As part of its gas storage optimization program, EnCana has entered into financial instruments and physical contracts at various locations and terms over the next 15 months to partially manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, three-way put spreads and put options.

The Company has a power purchase arrangement contract that expires in 2005. This contract was entered into as part of a cost management strategy.

Foreign Exchange
As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

The Company also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates
The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. The Company has entered into interest rate swap transactions from time to time as a means of managing the fixed/floating rate debt portfolio mix.

Credit Risk
The Company is exposed to credit related losses in the event of default by counterparties. The Company does not expect any counterparties to fail to meet their obligations because of credit practices that are in place that limit transactions to counterparties of investment grade credit quality. A substantial portion of the Company s accounts receivable is with customers in the oil and gas industry. Credit losses on the accounts receivable may arise as a result of non-performance by customers on their contractual obligations. To manage the Company s exposure to credit losses, Board-approved credit policies govern the Company s credit portfolio.

OPERATIONAL RISK

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company s projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project s results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for the Company s capital program with the results and identified learnings shared across the Company.

All projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project s history of Lookback results and the type of expenditure.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

The Company also partially mitigates operational risks by maintaining a comprehensive insurance program.

ENVIRONMENT, HEALTH, SAFETY AND SECURITY RISK

These risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana s Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to ensure that EnCana s personnel and assets are protected. EnCana has also established an Investigations Committee with the mandate to address potential violations of Company policies and practices.

Kyoto Protocol

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 2012. It is expected that the Federal Government will make a substantive announcement outlining its Climate Change action plan coinciding with Kyoto coming into force. The Climate Change Working Group of Canadian Association of Petroleum Producers is working with the Federal and Alberta governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry s competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

As the federal government has yet to release its Kyoto compliance plan, EnCana is unable to predict the impact of the potential regulations upon its business; however, it is possible that the Company would face increases in operating costs in order to comply with greenhouse gas emissions legislation.

REPUTATIONAL RISK

EnCana takes a pro-active approach to the identification and management of issues that affect the Company s reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana s reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

OUTLOOK

Volume Outlook for Continuing Operations

	2005 Guidance[2]	2004 Actual	Increase in 2005 [3]
Produced Gas Sales *(MMcf per day)*			
Canada	**2,200 - 2,300**	2,099	7%
United States	**1,150 - 1,200**	869	35%
Total Produced Gas Sales	**3,350 - 3,500**	2,968	15%
Crude Oil and NGLs *(Mbbls per day)*			
Canada	**135 - 155**	154	-6%
United States	**12 - 14**	12	8%
Total Crude Oil and NGLs	**150 - 170**	166	-4%
Total ***(MMcfe per day)*** [1]	**4,250 - 4,500**	3,966	10%

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(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Guidance released February 23, 2005.
(3) Using mid-point of guidance.

2005 Capital Investment for Continuing Operations

($ billions)	
Upstream	**$4.5 - $4.8**
Midstream & Marketing and Corporate	**0.4 - 0.4**
Core Capital	**$4.9 - $5.2**

EnCana plans to continue to focus principally on growing natural gas production and storage capacity in North America. The Company will also continue to invest in in situ oilsands development.

Strong natural gas storage injection requirements combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2004. The outlook for 2005 and beyond will be impacted by weather, timing of new supplies and economic activity.

Volatility in crude oil prices is expected to continue in 2005 as a result of market uncertainties over continued demand growth in China, the reliability of production from key producing countries, and OPEC success at managing prices and the overall state of the world economies.

The Company expects its 2005 core capital investment program, of between $4.9 billion and $5.2 billion, to be funded from cash flow.

EnCana s results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates. The following tables provide projected estimates for 2005 of the sensitivity of the Company s 2005 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

Sensitivity of 2005 Net Earnings From Continuing Operations and Cash Flow From Continuing Operations (Including Hedges)[(1)(2)]

($ millions)	**Net Earnings From Continuing Operations**	**Cash Flow From Continuing Operations**
$0.25 per million British thermal units increase in the NYMEX gas price	$ 95	$ 135
$1.00 per barrel increase in the WTI oil price	15	15
$0.01 decrease in the U.S.\ Canadian dollar exchange rate	(20)	5

(1) Hedge position as at December 31, 2004.
(2) Based on forward curve commodity price and forward curve estimates dated December 31, 2004.

Sensitivity of 2005 Net Earnings From Continuing Operations and Cash Flow From Continuing Operations (Excluding Hedges)[(1)]

($ millions)	**Net Earnings From Continuing Operations**	**Cash Flow From Continuing Operations**
$0.25 per million British thermal units increase in the NYMEX gas price	$ 185	$ 185
$1.00 per barrel increase in the WTI oil price	25	25
$0.01 decrease in the U.S.\ Canadian dollar exchange rate	(20)	5

(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2004.

These estimates are based on management s assumptions utilized for 2005 planning purposes, as discussed in this section. Assumptions include certain levels and profiles of capital expenditures, projected asset disposals, operating costs, projected sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other assumptions that impact operations. These assumptions can vary significantly from actual events and may result in material variances from the expected results.

In determining the current income tax expense deducted in arriving at these estimates, management has assumed a combined marginal tax rate of approximately 37 percent. This tax rate is itself affected in varying degrees by the assumptions referred to in the preceding paragraph.

ADVISORIES

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management s assessment of EnCana s and its subsidiaries future plans and operations, certain statements contained in this MD&A constitute forward-looking statements within the meaning of the safe harbour provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as anticipate , believe , expect , plan , intend , forecast , target , project words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: production and sales estimates for produced gas, crude oil and NGLs for 2005 and beyond; projections regarding Canadian and U.S. supply, demand and storage requirements; the Company s plans to focus on growing natural gas production and storage capacity in North America and medium and long-term growth prospects internationally; projections relating to the volatility of crude oil prices in 2005 and the reasons therefor; amounts which may be issued under the Company s multi-jurisdictional shelf prospectus program; the Company s projected capital investment levels for 2005 and the source of funding therefor; the effect of the Company s risk management program, including the impact of derivative financial instruments; the Company s execution of share purchases under its Normal Course Issuer Bid; the Company s defence of lawsuits; projections and assumptions relating to capital expenditures, operating costs, sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other variables impacting the Company and its operations; projections relating to expenses under the Company s Performance Share Units plan; anticipated asset retirement obligation expenses; the impact of the Kyoto Accord on operating costs; projected tax rates and projected current taxes payable for 2005 and the adequacy of the Company s provision for taxes; rating agency monitoring and reviews which may occur in the future; and the projected impact of off-balance sheet arrangements.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company s actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company s and its subsidiaries marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company s and its subsidiaries ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company s ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company s and its subsidiaries ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to reserves or resources or resource potential are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. 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. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement**.**

OIL AND GAS INFORMATION

EnCana s disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National

Instrument 51-101 (NI 51-101). The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading Note Regarding Reserves Data and Other Oil and Gas Information in EnCana s Annual Information Form.

Crude Oil, Natural Gas Liquids and Natural Gas Conversions
In this MD&A, certain crude oil and natural gas liquids (NGLs) volumes have been converted to millions of cubic feet equivalent (MMcfe) or thousands of cubic feet equivalent (Mcfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE), thousands of BOE (MBOE) or millions of BOE (MMBOE) on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

Resource Play, Estimated Ultimate Recovery and Resource Potential
EnCana uses the terms resource play, estimated ultimate recovery and resource potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time largely from a specified resource play or plays. EnCana s current stated estimates of unbooked resource potential utilize a five year time frame for their specified period of time.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA
All information included in this MD&A and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.79 for every Canadian dollar.

Non-GAAP Measures
Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles (Canadian GAAP) such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic and Cash Flow per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Operating Earnings from Continuing Operations per share diluted and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company s liquidity and its ability to generate funds to finance its operations. Management s use of these measures has been disclosed further in this MD&A as these measures are discussed and presented.

References To EnCana
For convenience, references in this MD&A to EnCana , the Company , we , us and our may, where applicable, ref only to or include any relevant direct and indirect subsidiary corporations and partnerships (Subsidiaries) of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

Additional Information

Further information regarding EnCana Corporation can be accessed under the Company s public filings found at www.sedar.com and on the Company s website at www.encana.com.

EnCana Corporation

CONSOLIDATED FINANCIAL STATEMENTS

Prepared in US$

For the Year Ended December 31, 2004

MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The financial statements have been prepared by Management in United States dollars in accordance with Canadian Generally Accepted Accounting Principles and include certain estimates that reflect Management s best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

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

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

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

(signed)
Gwyn Morgan
President &
Chief Executive Officer

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

February 7, 2005

AUDITORS REPORT

To the Shareholders of EnCana Corporation

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2004 and December 31, 2003 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company s Management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and December 31, 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

(signed)
PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada
February 7, 2005

Comments by Auditor for U.S. readers on Canada-U.S. Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company s financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Our report to the shareholders dated February 7, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors report when the change is properly accounted for and adequately disclosed in the financial statements.

(signed)
PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada
February 7, 2005

U.S. Dollars

EnCana Corporation

Consolidated Statement of Earnings

($ millions, except per share amounts)		For the years ended December 31, **2004**	2003	2002
Revenues, Net of Royalties	*(Note 4)*			
Upstream		**$ 7,256**	$ 5,797	$ 3,326
Midstream & Market Optimization		**4,749**	3,887	2,594
Corporate		**(195)**	2	8
		11,810	9,686	5,928
Expenses	*(Note 4)*			
Production and mineral taxes		**311**	164	105
Transportation and selling		**499**	484	332
Operating		**1,350**	1,196	749
Purchased product		**4,276**	3,455	2,200
Depreciation, depletion and amortization		**2,402**	1,989	1,186
Administrative		**197**	173	118
Interest, net	*(Note 7)*	**397**	283	286
Accretion of asset retirement obligation	*(Note 14)*	**22**	17	13
Foreign exchange gain	*(Note 8)*	**(417)**	(598)	(11)
Stock-based compensation		**17**	18	
Gain on dispositions	*(Note 6)*	**(113)**	(1)	(33)
		8,941	7,180	4,945
Net Earnings Before Income Tax		**2,869**	2,506	983
Income tax expense	*(Note 9)*	**658**	364	317
Net Earnings From Continuing Operations		**2,211**	2,142	666
Net Earnings From Discontinued Operations	*(Note 5)*	**1,302**	218	146
Net Earnings		**$ 3,513**	$ 2,360	$ 812
Net Earnings From Continuing Operations per Common Share	*(Note 18)*			
Basic		**$ 4.80**	$ 4.52	$ 1.59
Diluted		**$ 4.72**	$ 4.47	$ 1.58

Net Earnings per Common Share

	(Note 18)			
Basic		**$ 7.63**	$ 4.98	$ 1.94
Diluted		**$ 7.51**	$ 4.92	$ 1.92

Consolidated Statement of Retained Earnings

($ millions)		For the years ended December 31, **2004**	2003	2002
Retained Earnings, Beginning of Year		**$ 5,276**	$ 3,523	$ 2,819
Net Earnings		**3,513**	2,360	812
Dividends on Common Shares		**(183)**	(139)	(108)
Charges for Normal Course Issuer Bid	*(Note 15)*	**(671)**	(468)	
Retained Earnings, End of Year		**$ 7,935**	$ 5,276	$ 3,523

See accompanying notes to Consolidated Financial Statements.

U.S. Dollars

EnCana Corporation

Consolidated Balance Sheet

($ millions)		As at December 31, **2004**	2003
Assets			
Current Assets			
Cash and cash equivalents		**$ 602**	$ 113
Accounts receivable and accrued revenues		**1,898**	1,165
Risk management	*(Notes 2, 17)*	**336**	
Inventories	*(Note 10)*	**513**	557
Assets of discontinued operations	*(Note 5)*	**156**	781
		3,505	2,616
Property, Plant and Equipment, net	*(Notes 4, 11)*	**23,140**	17,770
Investments and Other Assets	*(Note 12)*	**334**	268
Risk Management	*(Notes 2, 17)*	**87**	
Assets of Discontinued Operations	*(Note 5)*	**1,623**	1,545
Goodwill		**2,524**	1,911
	(Note 4)	**$ 31,213**	$ 24,110
Liabilities and Shareholders Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,879**	$ 1,348
Income tax payable		**359**	32
Risk management	*(Notes 2, 17)*	**241**	
Liabilities of discontinued operations	*(Note 5)*	**280**	405
Current portion of long-term debt	*(Note 13)*	**188**	287
		2,947	2,072
Long-Term Debt	*(Note 13)*	**7,742**	6,088
Other Liabilities		**118**	21
Risk Management	*(Notes 2, 17)*	**192**	
Asset Retirement Obligation	*(Note 14)*	**611**	383
Liabilities of Discontinued Operations	*(Note 5)*	**102**	112
Future Income Taxes	*(Note 9)*	**5,193**	4,156

		16,905	12,832
Commitments and Contingencies	*(Note 19)*		
Shareholders Equity			
Share capital	*(Note 15)*	**5,299**	5,305
Share options, net		**10**	55
Paid in surplus		**28**	18
Retained earnings		**7,935**	5,276
Foreign currency translation adjustment		**1,036**	624
		14,308	11,278
		$ 31,213	$ 24,110

See accompanying notes to Consolidated Financial Statements.

Approved by the Board

(signed)
David P. O Brien
Director

(signed)
Barry W. Harrison
Director

U.S. Dollars

EnCana Corporation

Consolidated Statement of Cash Flows

($ millions)		For the years ended December 31, **2004**	2003	2002
Operating Activities				
Net earnings from continuing operations		**$ 2,211**	$ 2,142	$ 666
Depreciation, depletion and amortization		**2,402**	1,989	1,186
Future income taxes	*(Note 9)*	**91**	477	383
Unrealized loss on risk management	*(Note 17)*	**190**		
Unrealized foreign exchange gain	*(Note 8)*	**(285)**	(545)	(23)
Accretion of asset retirement obligation	*(Note 14)*	**22**	17	13
Gain on dispositions	*(Note 6)*	**(113)**	(1)	(33)
Other		**87**	56	(133)
Cash flow from continuing operations		**4,605**	4,135	2,059
Cash flow from discontinued operations		**375**	324	360
Cash flow		**4,980**	4,459	2,419
Net change in other assets and liabilities		**(176)**	(84)	(17)
Net change in non-cash working capital from continuing operations	*(Note 18)*	**1,455**	(568)	(889)
Net change in non-cash working capital from discontinued operations		**(1,668)**	497	104
		4,591	4,304	1,617
Investing Activities				
Business combinations	*(Note 3)*	**(2,335)**		(80)
Capital expenditures	*(Note 4)*	**(4,817)**	(4,627)	(2,771)
Proceeds on disposal of assets	*(Note 4)*	**1,144**	301	363
Dispositions (acquisitions)	*(Note 6)*	**386**	(91)	60
Equity investments		**47**	(6)	
Net change in investments and other		**45**	(15)	39
Net change in non-cash working capital from continuing operations	*(Note 18)*	**(21)**	(113)	195
Discontinued operations		**1,292**	822	(401)
		(4,259)	(3,729)	(2,595)

Financing Activities				
Net issuance of revolving long-term debt		**72**	288	
Issuance of long-term debt		**3,761**	500	1,506
Repayment of long-term debt		**(2,759)**	(142)	(1,206)
Issuance of common shares	*(Note 15)*	**281**	114	88
Purchase of common shares	*(Note 15)*	**(1,004)**	(868)	
Dividends on common shares		**(183)**	(139)	(108)
Other		**(5)**	(13)	(54)
Discontinued operations			(282)	272
		163	(542)	498
Deduct: Foreign Exchange Loss (Gain) on Cash and Cash Equivalents Held in Foreign Currency		**6**	10	(2)
Increase (Decrease) in Cash and Cash Equivalents		**489**	23	(478)
Cash and Cash Equivalents, Beginning of Year		**113**	90	568
Cash and Cash Equivalents, End of Year		**$ 602**	$ 113	$ 90
Supplemental Cash Flow Information	*(Note 18)*			

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana has adopted the U.S. dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana is in the business of exploration for, production and marketing of natural gas, crude oil and natural gas liquids, as well as natural gas storage, natural gas liquids processing and power generation operations.

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries (EnCana or the Company), and are presented in accordance with Canadian generally accepted accounting principles. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

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

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

B) Foreign Currency Translation

The accounts of self-sustaining 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 over the period. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the consolidated financial statements of future periods could be material.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance based compensation arrangements are subject to Management s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

D) Revenue Recognition

Revenues associated with the sales of EnCana s natural gas, crude oil and natural gas liquids (NGLs) are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company s commodity price risk management activities are recorded in revenue when the product is sold.

Marketing revenues and purchased product are recorded on a gross basis as the Company takes title to product and has risks and rewards of ownership. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company s commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) Transportation and Selling Costs

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

H) Income Taxes

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

I) Earnings Per Share Amounts

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

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

K) Inventories

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

L) Property, Plant and Equipment

Upstream

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

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and

ii. the costs of unproved properties that have been subject to a separate impairment test.

Midstream

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

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years.

M) Capitalization of Costs

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

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

N) Amortization of Other Assets

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

O) Goodwill

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

P) Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method. Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) Stock-based Compensation

EnCana records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option-pricing model. Compensation costs are recognized over the vesting period.

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

R) Derivative Financial Instruments

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

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

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2004.

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NOTE 2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

A) Hedging Relationships

On January 1, 2004, EnCana adopted the amendments made to the Canadian Institute of Chartered Accountants Accounting Guideline 13 (AcG 13) Hedging Relationships , and Emerging Issues Committee Abstract 128 (EIC 128 Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments . Derivative instruments that do not qualify as a hedge under AcG 13, or are not designated as a hedge, are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. The Company elected not to designate any of its risk management activities in place at December 31, 2003 as accounting hedges under AcG 13 and, accordingly, accounted for all these non-hedging derivatives using the mark-to-market accounting method.

The impact on EnCana s Consolidated Financial Statements at January 1, 2004, resulted in the recognition of risk management assets with a fair value of $145 million, risk management liabilities with a fair value of $380 million and a net deferred loss of $235 million. At December 31, 2004, a net unrealized gain remains to be recognized over the next four years as follows:

		Unrealized Gain
2005		
3 months ended March 31	$	
3 months ended June 30	14	
3 months ended September 30	9	
3 months ended December 31	9	
Total to be recognized in 2005		$ 32
2006	$ 24	
2007	15	
2008	1	
Total to be recognized in 2006 through to 2008		$ 40
Total to be recognized		$ 72
Total to be recognized Continuing Operations		$ 73
Total to be recognized Discontinued Operations		(1)
		$ 72

At December 31, 2004, the remaining net deferred amounts recognized on transition are recorded in the Consolidated Balance Sheet as follows:

As at December 31	**2004**
Accounts receivable and accrued revenues	**$ 11**
Investments and other assets	**4**
Accounts payable and accrued liabilities	**44**
Other liabilities	**44**
Total Net Deferred Gain Continuing Operations	**$ 73**
Total Net Deferred Loss Discontinued Operations	**(1)**
Total Net Deferred Gain	**$ 72**

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B) Consolidation of Variable Interest Entities

On November 1, 2004, the Company retroactively adopted the new CICA Accounting Guideline 15 (AcG 15) Consolidation of Variable Interest Entities . AcG 15 defines a variable interest entity (VIE) as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE s expected gains or losses, the primary beneficiary, to consolidate the VIE.

There was no effect on EnCana s Consolidated Financial Statements prior to the adoption of the guideline on November 1, 2004. Subsequent to November 1, 2004, the Company became the primary beneficiary of a VIE. At December 31, 2004, EnCana has consolidated this VIE as described in Note 4.

NOTE 3. BUSINESS COMBINATIONS

TOM BROWN, INC. (TBI)

On May 19, 2004, EnCana, through a wholly owned subsidiary, completed the tender offer for the shares of Tom Brown, Inc. (TBI), a Denver based independent energy company, for total cash consideration of $2.3 billion plus the assumption of $406 million of long-term debt.

As part of the acquisition, EnCana acquired certain natural gas and crude oil properties in west Texas and New Mexico and the assets of Sauer Drilling Company, a subsidiary of TBI, which were designated as assets held for sale at the date of acquisition. These assets were sold on July 30, 2004.

ALBERTA ENERGY COMPANY LTD. (AEC)

On April 5, 2002, PanCanadian Energy Corporation (PanCanadian) and Alberta Energy Company Ltd. completed a plan of arrangement (the Arrangement) under the Business Corporations Act (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. PanCanadian then changed its name to EnCana Corporation.

These business combinations have been accounted for using the purchase method with the results of operations included in the Consolidated Financial Statements from the dates of acquisition.

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The calculation of the purchase prices and the allocations to assets and liabilities is shown below:

	TBI	AEC
Calculation of Purchase Price:		
Common Shares issued to AEC shareholders *(millions)*		218.5
Price of Common Shares *(C$ per common share)*		38.43
Value of Common Shares issued		$ 5,281
Fair value of AEC share options exchanged for share options of EnCana Corporation (Share options)		105
Cash paid for common shares of TBI	$ 2,341	
Transaction costs	13	94
Total purchase price	$ 2,354	$ 5,480
Plus: Fair value of liabilities assumed		
Current liabilities	224	1,120
Long-term debt (including preferred securities)	406	3,714
Other non-current liabilities	39	180
Future income taxes	774	1,665
Total Purchase Price and Liabilities Assumed	$ 3,797	$ 12,159
Fair Value of Assets Acquired:		
Current assets (including cash acquired)	$ 425	$ 946
Property, plant and equipment, net	2,890	8,897
Other non-current assets	9	381
Goodwill	473	1,935
Total Fair Value of Assets Acquired	$ 3,797	$ 12,159
Goodwill Allocation:		
Upstream	$ 473	$ 1,504
Midstream & Market Optimization		49
	473	1,553
Discontinued Operations		382
Total Goodwill Allocation	$ 473	$ 1,935

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NOTE 4. SEGMENTED INFORMATION

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

Upstream includes the Company s exploration for, and development and production of, natural gas, crude oil and natural gas liquids and other related activities. The majority of the Company s Upstream operations are located in Canada and the United States. International new venture exploration is mainly focused on opportunities in Africa, South America, the Middle East and Greenland.

Midstream & Market Optimization is conducted by the Midstream & Marketing division. Midstream includes natural gas storage, natural gas liquids processing and power generation. The Marketing groups primary responsibility is the sale of the Company s proprietary production. These results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Midstream & Market Optimization segment.

Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative relates.

Midstream & Market Optimization purchases substantially all of the Company s North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Operations that have been discontinued are disclosed in Note 5.

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Results of Continuing Operations *(for the years ended December 31)*

	Upstream			Midstream & Market Optimization		
	2004	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 7,256**	$ 5,797	$ 3,326	**$ 4,749**	$ 3,887	$ 2,594
Expenses						
Production and mineral taxes	**311**	164	105			
Transportation and selling	**472**	429	245	**27**	55	87
Operating	**1,026**	872	562	**325**	324	187
Purchased product				**4,276**	3,455	2,200
Depreciation, depletion and amortization	**2,271**	1,900	1,115	**70**	48	36
Segment Income	**$ 3,176**	$ 2,432	$ 1,299	**$ 51**	$ 5	$ 84

	Corporate			Consolidated		
	2004	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ (195)**	$ 2	$ 8	**$ 11,810**	$ 9,686	$ 5,928
Expenses						
Production and mineral taxes				**311**	164	105
Transportation and selling				**499**	484	332
Operating	**(1)**			**1,350**	1,196	749
Purchased product				**4,276**	3,455	2,200
Depreciation, depletion and amortization	**61**	41	35	**2,402**	1,989	1,186
Segment Income	**$ (255)**	$ (39)	$ (27)	**2,972**	2,398	1,356
Administrative				**197**	173	118
Interest, net				**397**	283	286
Accretion of asset retirement obligation				**22**	17	13
Foreign exchange gain				**(417)**	(598)	(11)
Stock-based compensation				**17**	18	
Gain on dispositions				**(113)**	(1)	(33)
				103	(108)	373
Net Earnings Before Income Tax				**2,869**	2,506	983
Income tax expense				**658**	364	317
Net Earnings From Continuing Operations				**$ 2,211**	$ 2,142	$ 666

Results of Continuing Operations *(for the years ended December 31)*

	Canada			United States		
	2004	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 5,083**	$ 4,474	$ 2,796	**$ 1,941**	$ 1,143	$ 454
Expenses						
Production and mineral taxes	**87**	56	70	**224**	108	35
Transportation and selling	**352**	343	186	**120**	86	59
Operating	**685**	642	456	**119**	60	35
Depreciation, depletion and amortization	**1,751**	1,511	862	**475**	293	202
Segment Income	**$ 2,208**	$ 1,922	$ 1,222	**$ 1,003**	$ 596	$ 123

	Other			Total Upstream		
	2004	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 232**	$ 180	$ 76	**$ 7,256**	$ 5,797	$ 3,326
Expenses						
Production and mineral taxes				**311**	164	105
Transportation and selling				**472**	429	245
Operating	**222**	170	71	**1,026**	872	562
Depreciation, depletion and amortization	**45**	96	51	**2,271**	1,900	1,115
Segment Income	**$ (35)**	$ (86)	$ (46)	**$ 3,176**	$ 2,432	$ 1,299

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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	Midstream			Market Optimization			Total Midstream & Market Optimization		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Revenues	**$ 1,450**	$ 1,084	$ 440	**$ 3,299**	$ 2,803	$ 2,154	**$ 4,749**	$ 3,887	$ 2,594
Expenses									
Transportation and selling				**27**	55	87	**27**	55	87
Operating	**279**	261	174	**46**	63	13	**325**	324	187
Purchased product	**1,071**	762	169	**3,205**	2,693	2,031	**4,276**	3,455	2,200
Depreciation, depletion and amortization	**68**	40	24	**2**	8	12	**70**	48	36
Segment Income	**$ 32**	$ 21	$ 73	**$ 19**	$ (16)	$ 11	**$ 51**	$ 5	$ 84

Upstream Geographic and Product Information (Continuing Operations) *(for the years ended December 31)*

	Produced Gas								
	Canada			United States			Total		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 3,928**	$ 3,396	$ 1,882	**$ 1,776**	$ 1,051	$ 398	**$ 5,704**	$ 4,447	$ 2,280
Expenses									
Production and mineral taxes	**65**	52	50	**205**	101	32	**270**	153	82
Transportation and selling	**296**	274	151	**120**	86	59	**416**	360	210
Operating	**400**	342	255	**119**	60	35	**519**	402	290
Operating Cash Flow	**$ 3,167**	$ 2,728	$ 1,426	**$ 1,332**	$ 804	$ 272	**$ 4,499**	$ 3,532	$ 1,698

	Oil and NGLs								
	Canada			United States			Total		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 1,155**	$ 1,078	$ 914	**$ 165**	$ 92	$ 56	**$ 1,320**	$ 1,170	$ 970
Expenses									
Production and mineral taxes	**22**	4	20	**19**	7	3	**41**	11	23
Transportation and selling	**56**	69	35				**56**	69	35
Operating	**285**	300	201				**285**	300	201

Operating Cash Flow	**$ 792**	$ 705	$ 658	**$ 146**	$ 85	$ 53	**$ 938**	$ 790	$ 711

	Other			Total Upstream		
	2004	2003	2002	**2004**	2003	2002
Revenues, Net of Royalties	**$ 232**	$ 180	$ 76	**$ 7,256**	$ 5,797	$ 3,326
Expenses						
Production and mineral taxes				**311**	164	105
Transportation and selling				**472**	429	245
Operating	**222**	170	71	**1,026**	872	562
Operating Cash Flow	**$ 10**	$ 10	$ 5	**$ 5,447**	$ 4,332	$ 2,414

Capital Expenditures (Continuing Operations)

For the years ended December 31	**2004**	2003	2002
Upstream			
Canada	**$ 3,079**	$ 3,198	$ 1,388
United States	**1,549**	968	1,176
Other Countries	**79**	78	117
	4,707	4,244	2,681
Midstream & Market Optimization	**64**	276	47
Corporate	**46**	107	43
Total	**$ 4,817**	$ 4,627	$ 2,771

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On December 17, 2004, EnCana acquired certain natural gas and crude oil properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, Brown Ranger LLC, which holds the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The assets will be transferred to EnCana at the earlier of June 15, 2005 or upon the disposition of certain natural gas and crude oil properties by EnCana. EnCana has determined that the relationship with Brown Ranger LLC represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Ranger LLC from the date of acquisition.

In addition to the capital expenditures, during 2004, EnCana divested of mature conventional oil and gas assets and other property, plant and equipment for proceeds of $1,144 million (2003 $301 million; 2002 $363 million).

Additions to Goodwill

There was one addition to goodwill during 2004 (2003 none) as a result of the business combination with Tom Brown, Inc. (see Note 3).

Property, Plant and Equipment and Total Assets

As at December 31		Property, Plant and Equipment		Total Assets	
		2004	2003	**2004**	2003
Upstream		**$ 22,097**	$ 16,757	**$ 26,118**	$ 19,416
Midstream & Market Optimization		**804**	784	**1,904**	1,879
Corporate		**239**	229	**1,412**	489
Assets of Discontinued Operations	*(Note 5)*			**1,779**	2,326
Total		**$ 23,140**	$ 17,770	**$ 31,213**	$ 24,110

Export Sales
Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,747 million (2003 $1,484 million; 2002 $1,333 million).

Major Customers
In connection with the marketing and sale of EnCana s own and purchased natural gas and crude oil, for the year ended December 31, 2004, the Company had one customer (2003 two) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to this customer, a major international integrated energy company with a high quality investment grade credit rating, were approximately $1,709 million (2003 $1,362 million).

NOTE 5. DISCONTINUED OPERATIONS

2004

On December 1, 2004, the Company completed the sale of its 100 percent interest in EnCana (U.K.) Limited for net cash consideration of approximately $2.1 billion. EnCana s U.K. operations included crude oil and natural gas interests in the U.K. central North Sea including the Buzzard, Scott and Telford oil fields, as well as other satellite discoveries and exploration licenses. A gain on sale of approximately $1.4 billion was recorded. Accordingly, these operations have been accounted for as discontinued operations.

At December 31, 2004, EnCana has decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. EnCana s Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and

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Shiripuno, the non-operated economic interest in Block 15 and the 36.3 percent indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. (OCP), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. The majority of the Company s crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

2003

In 2003, in two separate transactions, the Company completed the sale of its 13.75 percent working interest and a gross overriding royalty in the Syncrude Joint Venture (Syncrude) for net cash consideration of $999 million.

2002

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

On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines operations for approximately $1 billion including the assumption of long-term debt by the purchaser. On January 2, 2003 and January 9, 2003, these sales were completed resulting in an after-tax gain on sale of $169 million.

CONSOLIDATED STATEMENT OF EARNINGS

The following tables present the effect of discontinued operations in the Consolidated Statement of Earnings:

2004

Upstream United Kingdom

For the years ended December 31	**2004**	2003	2002
Revenues, Net of Royalties	**$ 153**	$ 118	$ 103
Expenses			
Transportation and selling	**36**	16	11
Operating	**36**	18	11
Depreciation, depletion and amortization	**118**	74	39
Interest, net	**(9)**		
Accretion of asset retirement obligation	**3**	1	
Foreign exchange gain	**(2)**	(5)	(3)
(Gain) loss on disposition	**(1)**	1	
(Gain) loss on discontinuance	**(1,364)**		

	(1,183)	105	58
Net Earnings Before Income Tax	**1,336**	13	45
Income tax (recovery) expense	**(2)**	20	21
Net Earnings (Loss) From Discontinued Operations	**$ 1,338**	$ (7)	$ 24

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Upstream Ecuador

For the years ended December 31	**2004**	2003	2002
Revenues, Net of Royalties	**$ 471**	$ 412	$ 245
Expenses			
Production and mineral taxes	**61**	25	14
Transportation and selling	**60**	45	21
Operating	**125**	83	53
Depreciation, depletion and amortization	**263**	159	79
Administrative			1
Interest, net	**(3)**	4	4
Accretion of asset retirement obligation	**1**	1	
Foreign exchange loss	**5**	2	
	512	319	172
Net (Loss) Earnings Before Income Tax	**(41)**	93	73
Income tax (recovery) expense	**(8)**	61	28
Net (Loss) Earnings From Discontinued Operations	**$ (33)**	$ 32	$ 45

2003

Upstream Syncrude

For the years ended December 31	**2004**	2003	2002
Revenues, Net of Royalties	**$ (1)**	$ 87	$ 232
Expenses			
Transportation and selling		2	3
Operating		46	105
Depreciation, depletion and amortization		7	16
Interest, net			1
Loss on discontinuance	**2**		
	2	55	125
Net (Loss) Earnings Before Income Tax	**(3)**	32	107
Income tax expense		8	28

Net (Loss) Earnings From Discontinued Operations	**$ (3)**	$ 24	$ 79

2002

Midstream & Market Optimization

For the years ended December 31	Merchant Energy		Midstream Pipelines		Total	
	2003	2002	2003	2002	2003	2002
Revenues	$	$ 922	$	$ 135	$	$ 1,057
Expenses						
Operating				50		50
Purchased product		931				931
Depreciation, depletion and amortization				18		18
Administrative		22				22
Interest, net				19		19
Foreign exchange gain				(3)		(3)
Loss (gain) on discontinuance		19	(220)		(220)	19
		972	(220)	84	(220)	1,056
Net (Loss) Earnings Before Income Tax		(50)	220	51	220	1
Income tax (recovery) expense		(17)	51	20	51	3
Net (Loss) Earnings From Discontinued Operations	$	$ (33)	$ 169	$ 31	$ 169	$ (2)

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Consolidated Total

For the years ended December 31	**2004**	2003	2002
Revenues, Net of Royalties	**$ 623**	$ 617	$ 1,637
Expenses			
Production and mineral taxes	**61**	25	14
Transportation and selling	**96**	63	35
Operating	**161**	147	219
Purchased product			931
Depreciation, depletion and amortization	**381**	240	152
Administrative			23
Interest, net	**(12)**	4	24
Accretion of asset retirement obligation	**4**	2	
Foreign exchange loss (gain)	**3**	(3)	(6)
(Gain) loss on disposition	**(1)**	1	
(Gain) loss on discontinuance	**(1,362)**	(220)	19
	(669)	259	1,411
Net Earnings Before Income Tax	**1,292**	358	226
Income tax (recovery) expense	**(10)**	140	80
Net Earnings From Discontinued Operations	**$ 1,302**	$ 218	$ 146

CONSOLIDATED BALANCE SHEET

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

As at December 31	**2004**	2003
Assets		
Cash and cash equivalents	**$ 14**	$ 35
Accounts receivable and accrued revenues	**124**	202
Risk management	**3**	
Inventories	**15**	16
	156	253
Property, plant and equipment, net	**1,295**	1,775
Investments and other assets	**328**	298

	$ 1,779	$ 2,326
Liabilities		
Accounts payable and accrued liabilities	**$ 96**	$ 231
Income tax payable	**101**	33
Risk management	**72**	
	269	264
Asset retirement obligation	**22**	47
Future income taxes	**91**	206
	382	517
Net Assets of Discontinued Operations	**$ 1,397**	$ 1,809

The prices used in the ceiling test evaluation of the Company s crude oil reserves in Ecuador at December 31, 2004 were as follows:

	2005	2006	2007	2008	2009	% increase to 2016
Crude Oil *($/barrel)*	$ 33.27	$ 29.89	$ 23.47	$ 23.43	$ 23.45	13%

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Acquisition / Disposition

On January 31, 2003, the Company acquired the Ecuador interests of Vintage Petroleum Inc. (Vintage) for net cash consideration of $116 million. During the fourth quarter of 2003, the Company disposed of its interest in Block 27 in Ecuador for approximately $14 million.

Commitments and Contingencies

The Company is a shipper on the OCP Pipeline and has tariff commitments as follows:

As at December 31, 2004	2005	2006	2007	2008	2009	Thereafter	Total
Pipeline Transportation	$ 99	$ 93	$ 92	$ 93	$ 95	$ 837	$ 1,309

In Ecuador, a subsidiary of EnCana has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. During the year, Occidental Petroleum Corporation filed a Form 8-K indicating that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its Form 8-K, Occidental Petroleum Corporation indicated that it believes that it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

In addition to the above, the Company is proceeding with its arbitration related to value-added tax (VAT) owed to EnCana ($139 million at December 31, 2004). EnCana is also in discussions related to certain income tax matters related to the deductibility of interest expense in Ecuador.

NOTE 6. DISPOSITIONS (ACQUISITIONS)

For the years ended December 31	**2004**	2003	2002
Acquisitions			
Petrovera Resources	**$ (253)**	$	$
Savannah		(91)	
Other	**(34)**		
	(287)	(91)	
Dispositions			

Petrovera Resources	**540**		
Alberta Ethane Gathering System Joint Venture	**108**		
Kingston CoGen Limited Partnership	**25**		
EnCana Suffield Gas Pipeline Inc.			60
	673		60
	$ 386	$ (91)	$ 60

On December 22, 2004 EnCana completed the disposition of its interest in the Alberta Ethane Gathering System Joint Venture for approximately $108 million, including working capital. A $54 million pre-tax gain was recorded on this sale.

On December 15, 2004, EnCana sold its 25 percent limited partnership interest in the Kingston CoGen Limited Partnership (Kingston) for net cash consideration of $25 million. A pre-tax gain of $28 million was recorded on this sale.

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In March 2004, the Company sold its equity investment in a well servicing company for approximately $44 million, recording a pre-tax gain on sale of $34 million.

On February 18, 2004, the Company sold its 53.3 percent interest in Petrovera Resources for approximately $287 million, including working capital adjustments. In order to facilitate the transaction, the Company purchased the 46.7 percent interest of its partner for approximately $253 million, including working capital adjustments, and then sold the 100 percent interest for a total of approximately $540 million, including working capital adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. (Savannah) for net cash consideration of $91 million. Savannah s operations are in Texas, U.S.A.

In 2002, the Company sold its interest in EnCana Suffield Gas Pipeline Inc. for $60 million, recording a pre-tax gain on sale of $33 million.

NOTE 7. INTEREST, NET

For the years ended December 31	**2004**	2003	2002
Interest Expense Long-Term Debt	**$ 385**	$ 281	$ 252
Early Retirement of Long-Term Debt	**(16)**		34
Interest Expense Other	**42**	20	10
Interest Income	**(14)**	(18)	(10)
	$ 397	$ 283	$ 286

EnCana has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2004 by $22 million (2003 $23 million; 2002 $20 million).

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
8.75% due November 9, 2005 C$200 million	US$73 million	C$ Fixed	US$ Fixed*	4.99%
	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 4 basis points
7.50% due August 25, 2006 C$100 million	US$73 million	C$ Fixed	US$ Fixed*	4.14%

5.80% due June 2, 2008 C$225 million	US$71 million	C$ Fixed	US$ Fixed*	4.80%
	C$125 million	C$ Fixed	C$ Floating	3 month Bankers Acceptance less 5 basis points

* These instruments have been subject to multiple swap transactions.

NOTE 8. FOREIGN EXCHANGE GAIN

For the years ended December 31	**2004**	2003	2002
Unrealized Foreign Exchange Gain on Translation of U.S. Dollar Debt Issued in Canada	**$ (285)**	$ (545)	$ (23)
Realized Foreign Exchange (Gains) Losses	**(132)**	(53)	12
	$ (417)	$ (598)	$ (11)

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NOTE 9. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31	**2004**	2003	2002
Current			
Canada	**$ 594**	$ (136)	$ (26)
United States	**(12)**	39	(31)
Other	**(15)**	(16)	(9)
Total Current Tax	**567**	(113)	(66)
Future	**200**	836	403
Future Tax Rate Reductions	**(109)**	(359)	(20)
Total Future Tax	**91**	477	383
	$ 658	$ 364	$ 317

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

For the years ended December 31	**2004**	2003	2002
Net Earnings Before Income Tax	**$ 2,869**	$ 2,506	$ 983
Canadian Statutory Rate	**39.1%**	41.0%	42.3%
Expected Income Tax	**1,123**	1,026	416
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**192**	231	147
Canadian resource allowance	**(246)**	(258)	(200)
Canadian resource allowance on unrealized risk management losses	**(10)**		
Statutory and other rate differences	**(55)**	(45)	(35)
Effect of tax rate changes	**(109)**	(359)	(20)
Non-taxable capital gains	**(91)**	(119)	
Previously unrecognized capital losses	**17**	(119)	
Tax basis retained on dispositions	**(179)**		
Large corporations tax	**24**	27	23
Other	**(8)**	(20)	(14)
	$ 658	$ 364	$ 317

Effective Tax Rate	**22.9%**	14.5%	32.2%

The net future income tax liability is comprised of:

As at December 31	**2004**	2003
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,472**	$ 3,199
Timing of Partnership items	**1,005**	1,162
Future Tax Assets		
Net operating losses carried forward	**(103)**	(99)
Other	**(181)**	(106)
Net Future Income Tax Liability	**$ 5,193**	$ 4,156

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The approximate amounts of tax pools available are as follows:

As at December 31	**2004**	2003
Canada	**$ 7,183**	$ 6,904
United States	**3,009**	2,112
	$ 10,192	$ 9,016

Included in the above tax pools are $275 million (2003 $256 million) related to non-capital or net operating losses available for carry forward to reduce taxable income in future years.

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

NOTE 10. INVENTORIES

As at December 31	**2004**	2003
Product		
Upstream	**$ 14**	$ 6
Midstream & Market Optimization	**497**	546
Parts and Supplies	**2**	5
	$ 513	$ 557

NOTE 11. PROPERTY, PLANT AND EQUIPMENT, NET

As at December 31	**2004**			2003		
	Cost	**Accumulated DD&A***	**Net**	Cost	Accumulated DD&A*	Net
Upstream						
Canada	**$ 24,390**	**$ (9,775)**	**$ 14,615**	$ 20,607	$ (7,500)	$ 13,107
United States	**8,360**	**(1,056)**	**7,304**	4,062	(523)	3,539
Other Countries	**425**	**(247)**	**178**	316	(205)	111
Total Upstream	**33,175**	**(11,078)**	**22,097**	24,985	(8,228)	16,757

Midstream & Market Optimization	**975**		**(171)**	**804**	915		(131)	784
Corporate	**455**		**(216)**	**239**	320		(91)	229
	$ 34,605	**$**	**(11,465)**	**$ 23,140**	$ 26,220	$	(8,450)	$ 17,770

* Depreciation, depletion and amortization

Included in Midstream is $102 million (2003 $97 million; 2002 $47 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Included in property, plant and equipment are asset retirement costs, net of amortization, of $393 million (2003 $212 million). Administrative costs have not been capitalized as part of the capital expenditures.

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Upstream costs in respect of significant unproved properties and major development projects excluded from depletable costs at the end of the year were:

As at December 31	**2004**	2003	2002
Canada	**$ 1,444**	$ 1,444	$ 1,035
United States	**1,119**	499	604
Other Countries	**177**	112	111
	$ 2,740	$ 2,055	$ 1,750

The costs excluded from depletable costs in Other Countries represents costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. At December 31, 2004, the Company completed its impairment review of pre-production cost centres and determined that $23 million of costs should be charged to the Consolidated Statement of Earnings (2003 $85 million; 2002 nil).

The prices used in the ceiling test evaluation of the Company s crude oil and natural gas reserves at December 31, 2004 were:

	2005	2006	2007	2008	2009	% increase to 2016
Natural Gas *($/Mcf)*						
Canada	$ 6.00	$ 5.34	$ 4.52	$ 4.45	$ 4.58	12%
United States	6.24	5.61	4.35	4.77	4.77	13%
Crude Oil *($/barrel)*						
Canada	$ 28.66	$ 24.38	$ 17.03	$ 17.20	$ 16.88	7%
United States	43.51	38.84	26.95	26.49	26.45	18%
Natural Gas Liquids *($/barrel)*						
Canada	$ 38.61	$ 33.99	$ 25.65	$ 25.41	$ 25.25	17%
United States	38.18	34.54	26.93	27.14	27.22	14%

NOTE 12. INVESTMENTS AND OTHER ASSETS

As at December 31	**2004**	2003
Equity Investments	**$ 8**	$ 57
Marketing Contracts	**12**	22
Deferred Financing Costs	**61**	35
Deferred Pension Plan and Savings Plan	**64**	53
Prepaid Capital and Other	**189**	101
	$ 334	$ 268

Equity Investments

Included in Equity Investments is a 36 percent indirect equity investment in Oleoducto Trasandino which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile. In the second quarter of 2004, a $35 million impairment charge was made to depreciation, depletion and amortization on the Company s interest in Oleoducto Trasandino.

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NOTE 13. LONG-TERM DEBT

As at December 31	*Note*	**2004**	2003
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*B*	**$ 1,515**	$ 1,425
Unsecured notes and debentures	*C*	**1,309**	1,335
Preferred securities	*D*		252
		2,824	3,012
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	*E*	**399**	417
Unsecured notes and debentures	*F*	**4,641**	2,713
Preferred securities	*D*		150
		5,040	3,280
Increase in Value of Debt Acquired	*G*	**66**	83
Current Portion of Long-Term Debt	*H*	**(188)**	(287)
		$ 7,742	$ 6,088

A) Overview

Revolving credit and term loan borrowings

At December 31, 2004, EnCana had in place a revolving credit facility for $4.5 billion Canadian dollars or its equivalent amount in U.S. dollars ($3.7 billion). The facility consists of two tranches of C$1.7 billion ($1.4 billion) and C$2.8 billion ($2.3 billion) respectively. The first tranche is fully revolving for a period of three years from the date of the agreement, October 2004. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from EnCana. The second tranche is fully revolving for a period of five years from the date of the agreement, October 2004. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from the Company. The facility is unsecured and bears interest at either the lenders rates for Canadian prime commercial loans, U.S. base rate loans, Bankers Acceptances rates, or at LIBOR plus applicable margins.

To fund the acquisition of Tom Brown, Inc., EnCana arranged a $3 billion non-revolving term loan facility. Initially, $1.8 billion was drawn on this facility. At December 31, 2004, this facility has been completely repaid and cancelled.

At December 31, 2004, one of EnCana s subsidiaries had in place a credit facility totaling $600 million (C$722 million). The facility is guaranteed by EnCana Corporation and fully revolving for five years from the date of the Agreement, December, 2004. The facility is extendable annually for an additional one year period at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders U.S. base rate or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers Acceptances and Commercial Paper of $1,559 million (2003 $1,749 million) maturing at various dates with a weighted average interest rate of 2.83% (2003 2.55%) and LIBOR loans of $355 million (2003 $65 million) with a weighted average interest rate of 2.98% (2003 1.69%). These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2004 relating to revolving credit and term loan agreements were approximately $5 million (2003 $3 million; 2002 $3 million).

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Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company s current medium term note program was renewed in 2003 with C$1 billion ($831 million) unutilized at December 31, 2004. The notes may be denominated in Canadian dollars or in foreign currencies.

EnCana has in place a shelf prospectus for U.S. Unsecured Notes in the amount of $2 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. At December 31, 2004, $2 billion of the shelf prospectus remains unutilized.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a shelf prospectus in the amount of $2 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. At December 31, 2004, $1 billion of the shelf prospectus remains unutilized.

B) Canadian revolving credit and term loan borrowings

	C$ Principal Amount	**2004**	2003
Bankers Acceptances	**$ 615**	**$ 511**	$ 598
Commercial Paper	**1,209**	**1,004**	799
Cogeneration Facility, matures March 31, 2016 *			28
	$ 1,824	**$ 1,515**	$ 1,425

* On December 15, 2004, EnCana sold its limited partnership interest in Kingston. See Note 6.

C) Canadian unsecured notes and debentures

C$
Principal

	Amount	2004	2003
6.60% due June 30, 2004	$	$	$ 39
7.00% due December 1, 2004			77
5.95% due October 1, 2007	**200**	**166**	155
5.30% due December 3, 2007	**300**	**248**	232
5.95% due June 2, 2008	**100**	**83**	77
5.80% due June 2, 2008	**125**	**104**	97
5.80% due June 19, 2008	**100**	**83**	77
6.10% due June 1, 2009	**150**	**125**	116
7.15% due December 17, 2009	**150**	**125**	116
8.50% due March 15, 2011	**50**	**42**	39
7.10% due October 11, 2011	**200**	**166**	155
7.30% due September 2, 2014	**150**	**125**	116
5.50% / 6.20% due June 23, 2028	**50**	**42**	39
	$ 1,575	**$ 1,309**	$ 1,335

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D) Preferred securities

	C$ Principal Amount	**2004**	2003
Canadian Dollar			
7.00% due March 23, 2034	**$**	**$**	$ 97
8.50% due September 30, 2048			155
	$		252
U.S. Dollar			
9.50% due September 30, 2048			150
		$	$ 402

All of the preferred securities were redeemed during 2004 at par plus accrued and unpaid interest.

E) U.S. revolving credit and term loan borrowings

	2004	2003
Commercial Paper	**$ 44**	$ 352
LIBOR Loan	**355**	65
	$ 399	$ 417

F) U.S. unsecured notes and debentures

	C$ Amount	**2004**	2003
Floating Rate			
8.40% due December 15, 2004	**$**	**$**	$ 73
8.75% due November 9, 2005	**88***	**73**	73
Fixed Rate			

8.75% due November 9, 2005	**88***	**73**	73
7.50% due August 25, 2006	**88***	**73**	73
5.80% due June 2, 2008	**85***	**71**	71
4.60% due August 15, 2009		**250**	
7.65% due September 15, 2010		**200**	200
6.30% due November 1, 2011		**500**	500
7.25% due September 15, 2013		**1**	
4.75% due October 15, 2013		**500**	500
5.80% due May 1, 2014		**1,000**	
8.125% due September 15, 2030		**300**	300
7.20% due November 1, 2031		**350**	350
7.375% due November 1, 2031		**500**	500
6.50% due August 15, 2034		**750**	
		$ 4,641	$ 2,713

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

The 5.80% Notes due May 1, 2014 were issued by the Company s indirect wholly owned subsidiary, EnCana Holdings Finance Corp. These notes are fully and unconditionally guaranteed by EnCana Corporation.

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G) Increase in value of debt acquired

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 22 years.

H) Current portion of long-term debt

	2004	2003
7.00% Coupon Reset Subordinated Term Securities due March 23, 2034	**$**	$ 97
6.60% Medium Term Note due June 30, 2004		39
7.00% Medium Term Note due December 1, 2004		77
8.40% Medium Term Note due December 15, 2004		73
5.50% / 6.20% Medium Term Note due June 23, 2028	**42**	
8.75% Unsecured Note due November 9, 2005	**146**	
Cogeneration facility		1
	$ 188	$ 287

The 5.50% / 6.20% Medium Term Note due June 23, 2028 has a put option attached to it whereby holders of the note may require EnCana to repay the outstanding note on June 23, 2005, if the notice is given prior to June 9, 2005 that the option will be exercised. Should notice not be received, the note is then payable on June 23, 2028.

I) Mandatory debt payments

	C$ Principal Amount	US$ Principal Amount	**Total US$ Equivalent**
2005	$ 50	$ 146	**$ 188**
2006		73	**73**
2007	500		**414**
2008	325	71	**341**
2009	300	250	**500**
Thereafter	2,224	4,500	**6,348**
Total	$ 3,399	$ 5,040	**$ 7,864**

The amount due in 2005 excludes Bankers Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

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NOTE 14. ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties.

As at December 31	**2004**	2003
Asset Retirement Obligation, Beginning of Year	**$ 383**	$ 288
Liabilities Incurred	**98**	45
Liabilities Settled	**(16)**	(23)
Liabilities Disposed	**(35)**	
Change in Estimated Future Cash Flows	**124**	
Accretion Expense	**22**	17
Other	**35**	56
Asset Retirement Obligation, End of Year	**$ 611**	$ 383

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,695 million (2003 $3,118 million), which has been discounted using a credit-adjusted risk free rate of 6.0 percent (2003 5.9 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at that time.

NOTE 15. SHARE CAPITAL

Authorized

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

Issued and Outstanding

As at December 31	**2004**		2003	
	Number *(millions)*	**Amount**	Number *(millions)*	Amount
Common Shares Outstanding, Beginning of Year	**460.6**	**$ 5,305**	478.9	$ 5,511
Shares Issued under Option Plans	**9.7**	**281**	5.5	114
Shares Repurchased	**(20.0)**	**(287)**	(23.8)	(320)

Common Shares Outstanding, End of Year	**450.3**	**$ 5,299**	460.6	$ 5,305

Normal Course Issuer Bid

On October 26, 2004, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 29, 2004. Under this bid, the Company may purchase for cancellation up to 23,114,500 of its Common Shares, representing five percent of the approximately 462.29 million Common Shares outstanding as of the filing of the bid on October 22, 2004. On February 4, 2005, the Company received regulatory approval for an amendment to the Normal Course Issuer Bid which increases the number of shares available for purchase from five percent of the issued and outstanding Common Shares to ten percent of the public float of Common Shares (a total of approximately 46.1 million Common Shares). The current Normal Course Issuer Bid expires on October 28, 2005.

On October 20, 2003, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 22, 2003. Under this bid, the Company could purchase for cancellation up to 23,212,341 of its Common Shares, representing five percent of the 464,246,813 Common Shares outstanding as of October 14, 2003.

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In 2004, the Company purchased, for cancellation, 19,983,600 Common Shares for total consideration of $1,004 million. Of the $1,004 million paid, $287 million was charged to Share capital, $46 million was charged to Paid in surplus and $671 million was charged to Retained earnings.

Stock Options

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the grant date. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

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

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase Common Shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. All options issued in 2004 have an associated Tandem Share Appreciation Right (TSAR) attached to them (see Note 16).

Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited (CPL), EnCana s former parent company, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL s stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

Directors Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase common shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued.

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The following tables summarize the information about options to purchase Common Shares that have no TSAR attached to them:

As at December 31	**2004**		2003		2002	
	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*
Outstanding, Beginning of Year	**28.8**	**43.13**	29.6	39.74	10.5	32.31
Granted under EnCana Plan			6.3	47.98	12.1	48.13
Granted under AEC Replacement Plan					13.1	32.01
Granted under Directors Plan			0.1	47.87	0.1	48.04
Exercised	**(9.7)**	**36.63**	(5.5)	29.11	(5.5)	25.20
Forfeited	**(1.0)**	**47.50**	(1.7)	41.18	(0.7)	43.81
Outstanding, End of Year	**18.1**	**46.29**	28.8	43.13	29.6	39.74
Exercisable, End of Year	**10.8**	**45.09**	15.6	38.92	17.7	34.10

As at December 31	**Outstanding Options**			**Exercisable Options**	
Range of Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
13.50 to 19.99	0.1	0.2	18.49	0.1	18.49
20.00 to 24.99	0.6	3.5	22.69	0.6	22.69
25.00 to 29.99	0.4	1.3	26.18	0.4	26.18
30.00 to 43.99	0.5	1.7	40.18	0.4	39.93
44.00 to 53.00	16.5	2.4	47.97	9.3	47.87
	18.1	2.4	46.29	10.8	45.09

At December 31, 2004, there were 8.0 million common shares reserved for issuance under stock option plans (2003 7.8 million; 2002 12.4 million).

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share in 2004 would have been $3,476 million; $7.55 per common share basic; $7.43 per common share diluted (2003 $2,326 million; $4.91 per common share basic; $4.85 per common share diluted).

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

For the years ended December 31	2003	2002
Weighted Average Fair Value of Options Granted *(C$)*	$ 12.21	$ 13.31
Risk-Free Interest Rate	3.87%	4.29%
Expected Lives *(years)*	3.00	3.00
Expected Volatility	0.33	0.35
Annual Dividend per Share *(C$/common share)*	$ 0.40	$ 0.40

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NOTE 16. COMPENSATION PLANS

A) Pensions

The most recent actuarial evaluation completed for the Company is dated December 31, 2004.

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits (OPEB) to substantially all of its employees.

For the years ended December 31	**2004**	2003	2002
Total Expense for Defined Contribution Plans	**$ 19**	$ 12	$ 9

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

As at December 31	Pension Benefits		OPEB	
	2004	2003	**2004**	2003
Accrued Benefit Obligation, Beginning of Year	**$ 214**	$ 159	**$ 14**	$ 8
Beginning of year adjustment	**(1)**			
Current service cost	**5**	5	**1**	1
Interest cost	**13**	11	**1**	1
Benefits paid	**(10)**	(11)		
Actuarial loss	**8**	12	**1**	1
Contributions	**1**	1		
Plan amendments				1
Foreign exchange	**16**	37	**2**	2
Accrued Benefit Obligation, End of Year	**$ 246**	$ 214	**$ 19**	$ 14

As at December 31	Pension Benefits		OPEB	
	2004	2003	**2004**	2003
Fair Value of Plan Assets, Beginning of Year	**$ 203**	$ 117	**$**	$
Beginning of year adjustment		(1)		
Actual return on plan assets	**19**	16		
Employer contributions	**17**	51		
Employees contributions	**1**	1		

Benefits paid		**(10)**		(10)				
Foreign exchange		**17**		29				
Fair Value of Plan Assets, End of Year	**$**	**247**	$	203	**$**		$	

As at December 31	Pension Benefits				OPEB			
	2004		2003		**2004**		2003	
Funded Status Plan Assets less than Benefit Obligation	**$**	**1**	$	(11)	**$**	**(19)**	$	(14)
Amounts Not Recognized:								
Unamortized net actuarial loss		**54**		64		**4**		2
Unamortized past service cost		**10**		12		**2**		1
Net transitional asset		**(11)**		(12)		**2**		3
Accrued Benefit Asset	**$**	**54**	$	53	**$**	**(11)**	$	(8)

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As at December 31	Pension Benefits		OPEB	
	2004	2003	**2004**	2003
Prepaid Benefit Cost	**$ 54**	$ 53	**$**	$
Accrued Benefit Cost			**(11)**	(8)
Net Amount Recognized	**$ 54**	$ 53	**$ (11)**	$ (8)

The Company s other post employment benefit plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

As at December 31	Pension Benefits		OPEB	
	2004	2003	**2004**	2003
Discount Rate	**5.75%**	6.00%	**5.75%**	6.00%
Rate of Compensation Increase	**4.60%**	4.75%	**5.65%**	5.75%

The weighted average assumptions used to determine periodic expense are as follows:

For the years ended December 31	Pension Benefits		OPEB	
	2004	2003	**2004**	2003
Discount Rate	**6.00%**	6.50%	**6.00%**	6.50%
Expected Long-Term Rate of Return on Plan Assets				
Registered pension plans	**6.75%**	6.75%	**n/a**	n/a
Supplemental pension plans	**3.375%**	3.375%	**n/a**	n/a
Rate of Compensation Increase	**4.75%**	4.75%	**5.75%**	5.75%

The periodic expense for benefits is as follows:

For the years ended December 31	Pension Benefits			OPEB		
	2004	2003	2002	**2004**	2003	2002

Current Service Cost	**$ 5**	$ 5	$ 2	**$ 1**	$ 1	$ 1
Interest Cost	**13**	11	8	**1**	1	
Actual Return on Plan Assets	**(19)**	(16)	9			
Actuarial Loss on Accrued Benefit Obligation	**8**	12	9	**1**	1	
Plan Amendment			9		2	
Difference Between Actual and:						
Expected return on plan assets	**7**	7	(17)			
Recognized actuarial loss	**(4)**	(8)	(8)	**(1)**	(1)	
Difference Between Amortization of Past						
Service Costs and Actual Plan Amendments	**2**	1	(8)		(2)	
Amortization of Transitional Obligation	**(2)**	(2)	(2)			
Curtailment Loss			1			
Special Termination Benefits			2			
Expense for Defined Contribution Plan	**19**	12	9			
Net Benefit Plan Expense	**$ 29**	$ 22	$ 14	**$ 2**	$ 2	$ 1

The average remaining service period of the active employees covered by the defined benefit pension plan is eight years. The average remaining service period of the active employees covered by the other retirement benefits plan is 12 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting

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purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

Assumed health care cost trend rates are as follows:

As at December 31	**2004**	2003
Health Care Cost Trend Rate for Next Year	**10.00%**	10.00%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2015**	2014

Assumed health care cost trend rates have an effect on the amounts reported for the other benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on Total of Service and Interest Cost	$	$
Effect on Post Retirement Benefit Obligation	$ 2	$ (1)

The Company s pension plan asset allocations are as follows:

Asset Category	Target Allocation % Normal	Target Allocation % Range	% of Plan Assets at December 31 **2004**	% of Plan Assets at December 31 2003	Expected Long-Term Rate of Return
Domestic Equity	35	25-45	**38**	35	
Foreign Equity	30	20-40	**28**	29	
Bonds	30	20-40	**27**	27	
Real Estate and Other	5	0-20	**7**	9	
Total	100		**100**	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan (approximately $40 million) is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposure.

The Company expects to contribute $6 million to the plans in 2005. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2004 (2003 $1 million; 2002 nil).

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Estimated future payments for pension and other benefits are as follows:

	Pension Benefits	OPEB
2005	$ 12	$
2006	13	1
2007	13	1
2008	14	1
2009	15	1
2010 2014	88	7
Total	$ 155	$ 11

B) Share Appreciation Rights

EnCana has in place a program whereby certain employees are granted Share Appreciation Rights (SAR s) which entitle the employee to receive a cash payment equal to the excess of the market price of the Company s Common Shares at the time of exercise over the exercise price of the right. SAR s granted expire after five years.

The following tables summarize the information about the SAR s:

As at December 31	**2004**		2003	
	Outstanding SAR s	**Weighted Average Exercise Price**	Outstanding SAR s	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*				
Outstanding, Beginning of Year	**1,175,070**	**35.87**	2,284,901	35.56
Exercised	**(698,775)**	**35.48**	(1,101,987)	35.17
Forfeited	**(11,040)**	**29.25**	(7,844)	46.28
Outstanding, End of Year	**465,255**	**36.61**	1,175,070	35.87
Exercisable, End of Year	**465,255**	**36.61**	1,175,070	35.87
U.S. Dollar Denominated *(US$)*				
Outstanding, Beginning of Year	**753,417**	**28.98**	1,346,437	28.52

Exercised	**(365,647)**	**29.19**	(589,340)	27.91
Forfeited	**(1,840)**	**25.29**	(3,680)	30.73
Outstanding, End of Year	**385,930**	**28.80**	753,417	28.98
Exercisable, End of Year	**385,930**	**28.80**	753,417	28.98

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As at December 31	SAR s Outstanding		
Range of Exercise Price	**Number of SAR s**	**Weighted Average Remaining Contractual Life *(years)***	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*			
20.00 to 29.99	225,327	0.153	26.24
30.00 to 39.99			
40.00 to 49.99	238,416	1.190	46.31
50.00 to 60.00	1,512	1.332	51.94
	465,255	0.689	36.61
U.S. Dollar Denominated *(US$)*			
20.00 to 29.99	166,640	1.379	26.69
30.00 to 40.00	219,290	1.158	30.39
	385,930	1.254	28.80

During the year, the Company recorded compensation costs of $17 million related to the outstanding SAR s (2003 $12 million; 2002 $4 million).

C) Tandem Share Appreciation Rights

In 2004, all options to purchase common shares issued have an associated Tandem Share Appreciation Right (TSAR) attached to them whereby the option holder has the right to receive cash payment equal to the excess of the market price of the Company s Common Shares at the time of exercise over the exercise price of the right. These TSAR s expire after five years.

The following tables summarize the information about the TSAR s:

As at December 31	2004	
	Outstanding TSAR s	**Weighted Average Exercise Price**

Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year		
Granted	**1,080,450**	**55.31**
Forfeited	**(212,950)**	**54.37**
Outstanding, End of Year	**867,500**	**55.54**
Exercisable, End of Year		

As at December 31	TSAR s Outstanding		
Range of Exercise Price	**Number of TSAR s**	**Weighted Average Remaining Contractual Life** ***(years)***	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*			
50.00 to 59.99	784,000	4.359	54.75
60.00 to 70.00	83,500	4.874	62.91
	867,500	4.408	55.54

During the year, the Company recorded compensation costs of $3 million related to the outstanding

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TSAR s.

D) Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units (DSU s), which are equivalent in value to a common share of the Company. DSU s granted to directors vest immediately. DSU s granted to Senior Executives in 2002 vest over a three year period. DSU s expire on December 15th of the year following the employee s retirement or death.

The following table summarizes the information about the DSU s:

As at December 31	**2004**		2003	
	Outstanding DSU s	**Average Share Price**	Outstanding DSU s	Average Share Price
Canadian Dollar Denominated *(C$)*				
Outstanding, Beginning of Year	**319,250**	**48.68**	309,167	48.69
Granted, Directors	**58,931**	**54.04**	36,402	48.20
Units, in lieu of dividends	**3,208**	**59.86**	2,723	46.72
Exercised	**(6,083)**	**48.68**	(29,042)	48.04
Outstanding, End of Year	**375,306**	**49.61**	319,250	48.68
Exercisable, End of Year	**293,955**	**52.55**	80,645	48.68

During the year, the Company recorded compensation costs of $10 million related to the outstanding DSU s (2003 $4 million; 2002 $4 million).

E) Performance Share Units

EnCana has in place a program whereby employees may be granted Performance Share Units (PSU s) which entitle the employee to receive, upon vesting, either a common share of EnCana or a cash payment equal to the value of one common share of EnCana depending upon the terms of the PSU granted. PSU s vest at the end of a three year period. Their ultimate value will depend upon EnCana s performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed North American oil and gas comparison group. If EnCana s performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana s performance is at or above the specified level compared to the comparison group, the value of the PSU s shall be determined by EnCana s relative ranking, with payments ranging from one to two times for PSU s granted for the 2003 grant and one half to two times the PSU s granted for the 2004 grant.

PSU s granted in 2004 are to be paid in common shares (2003 paid in cash).

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The following table summarizes the information about the PSU s:

As at December 31	**2004**		2003	
	Outstanding PSU's	**Average Share Price**	Outstanding PSU's	Average Share Price
Canadian Dollar Denominated *(C$)*				
Outstanding, Beginning of Year	**126,283**	**46.52**		
Granted	**1,690,790**	**53.95**	128,893	46.52
Forfeited	**(169,970)**	**53.51**	(2,610)	46.52
Outstanding, End of Year	**1,647,103**	**53.42**	126,283	46.52
Exercisable, End of Year				
U.S. Dollar Denominated *(US$)*				
Outstanding, Beginning of Year				
Granted	**250,224**	**41.12**		
Forfeited	**(25,609)**	**41.12**		
Outstanding, End of Year	**224,615**	**41.12**		
Exercisable, End of Year				

During the year, the Company recorded compensation costs of $25 million related to the outstanding PSU s (2003 $1 million; 2002 nil).

NOTE 17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, EnCana has entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

As discussed in Note 2, on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount. The deferred loss is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with the associated unrealized gain or loss recorded in net earnings. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

The following table presents a reconciliation of the change in the unrealized amounts during 2004:

	Net Deferred Amounts Recognized on Transition	Fair Market Value	Total Unrealized Gain/(Loss)
Fair Value of Contracts, January 1, 2004	$ 235	$ (235)	$
Change in Fair Value of Contracts Still Outstanding at December 31, 2004		78	78
Fair Value of Contracts Realized During 2004	(307)	307	
Fair Value of Contracts Entered into During 2004		(339)	(339)
Fair Value of Contracts Outstanding	$ (72)	$ (189)	$ (261)
Premiums Paid on Collars and Options		110	
Fair Value of Contracts Outstanding and Premiums Paid, End of Year		$ (79)	
Amounts Allocated to Continuing Operations	$ (73)	$ (10)	$ (190)
Amounts Allocated to Discontinued Operations	1	(69)	(71)
	$ (72)	$ (79)	$ (261)

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The total realized loss recognized in net earnings from continuing operations for the year ended December 31, 2004 was $464 million ($686 million, before tax).

At December 31, 2004, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

As at December 31		**2004**
Risk Management		
Current asset		**$ 336**
Long-term asset		**87**
Current liability		**241**
Long-term liability		**192**
Net Risk Management Liability	Continuing Operations	**(10)**
Net Risk Management Liability	Discontinued Operations	**(69)**
		$ (79)

A summary of all unrealized estimated fair value financial positions is as follows:

As at December 31		*Note*	**2004**	2003
Commodity Price Risk		*A*		
Natural gas			**$ 107**	$ (13)
Crude oil			**(143)**	(174)
Power			**2**	4
Foreign Currency Risk		*B*		7
Interest Rate Risk		*C*	**24**	45
Total Fair Value Positions	Continuing Operations		**(10)**	(131)
Total Fair Value Positions	Discontinued Operations		**(69)**	(104)
			$ (79)	$ (235)

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A) Commodity Price Risk

Natural Gas

At December 31, 2004 the gas risk management activities from financial contracts had an unrealized gain of $36 million and a fair market value position of $107 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	481	2005	6.72	US$/Mcf	$ 81
Colorado Interstate Gas (CIG)	113	2005	4.87	US$/Mcf	(27)
Other	110	2005	5.21	US$/Mcf	(23)
NYMEX Fixed Price	525	2006	5.66	US$/Mcf	(105)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(37)
Other	171	2006	4.85	US$/Mcf	(59)
Collars and Other Options					
Purchased NYMEX Put Options	906	2005	5.46	US$/Mcf	29
Other	5	2005	4.57 - 7.23	US$/Mcf	
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(13)
Purchased NYMEX Put Options	210	2006	5.00	US$/Mcf	5
Basis Contracts					
Fixed NYMEX to AECO basis	877	2005	(0.66)	US$/Mcf	70
Fixed NYMEX to Rockies basis	268	2005	(0.49)	US$/Mcf	19
Other	442	2005	(0.47)	US$/Mcf	4
Fixed NYMEX to AECO basis	703	2006	(0.65)	US$/Mcf	41
Fixed NYMEX to Rockies basis	312	2006	(0.57)	US$/Mcf	14
Fixed NYMEX to CIG basis	279	2006	(0.83)	US$/Mcf	(9)
Other	182	2006	(0.36)	US$/Mcf	2
Fixed Rockies to CIG basis	12	2007	(0.10)	US$/Mcf	
Fixed NYMEX to AECO basis	345	2007-2008	(0.65)	US$/Mcf	17
Fixed NYMEX to Rockies basis	248	2007-2008	(0.57)	US$/Mcf	14
Fixed NYMEX to CIG basis	110	2007-2009	(0.68)	US$/Mcf	5

Purchase Contracts						
Fixed Price Contract	Waha Purchase	27	2005	5.90	US$/Mcf	(2)
Fixed Price Contract	Waha Purchase	23	2006	5.32	US$/Mcf	3
						29
Gas Storage Optimization Financial Positions						2
Gas Marketing Financial Positions [(1)]						5
Total Unrealized Gain on Financial Contracts						36
Premiums Paid on Options						71
Total Fair Value Positions						$ 107

(1) The gas marketing activities are part of the daily ongoing operations of the Company s proprietary production management.

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Crude Oil

As at December 31, 2004, the Company s oil risk management activities from all financial contracts had an unrealized loss of $251 million and a fair market value position of $(212) million. The contracts were as follows:

	Notional Volumes *(bbls/d)*	Term	Average Price	Fair Market Value
Fixed WTI NYMEX Price	41,000	2005	28.41	$ (209)
Costless 3-Way Put Spread	9,000	2005	20.00/25.00/28.78	(45)
Unwind WTI NYMEX Fixed Price	(4,500)	2005	35.90	11
Purchased WTI NYMEX Call Options	(38,000)	2005	49.76	13
Purchased WTI NYMEX Put Options	35,000	2005	40.00	13
Fixed WTI NYMEX Price	15,000	2006	34.56	(31)
Purchased WTI NYMEX Put Options	22,000	2006	27.36	(2)
				(250)
Crude Oil Marketing Financial Positions[1]				(1)
Total Unrealized Loss on Financial Contracts				(251)
Premiums Paid on Options				39
Total Fair Value Positions				$ (212)
Total Fair Value Positions Continuing Operations				$ (143)
Total Fair Value Positions Discontinued Operations				(69)
				$ (212)

(1) The crude oil marketing activities are part of the daily ongoing operations of the Company s proprietary production management.

Power

EnCana has one electricity contract which expires in 2005. The contract was entered into as part of an electricity cost management strategy. At December 31, 2004, the unrealized gain on the contract was $2 million.

B) Foreign Currency Risk

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

No forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2004.

C) Interest Rate Risk

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

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The unrealized gains on the outstanding financial instruments as at December 31, 2004 were as follows:

	Unrealized Gain
5.80% Medium Term Notes	$ 11
7.50% Medium Term Notes	5
8.75% Debenture	8
	$ 24

At December 31, 2004, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $13 million (2003 $14 million).

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments not recorded at their fair values that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

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

As at December 31	**2004**		2003	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	**$ 602**	**$ 602**	$ 113	$ 113
Accounts receivable	**1,898**	**1,898**	1,165	1,165
Financial Liabilities				
Accounts payable, income taxes payable	**$ 2,238**	**$ 2,238**	$ 1,380	$ 1,380
Long-term debt	**7,930**	**8,479**	6,375	6,767

E) Credit Risk

A substantial portion of the Company s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board has approved a credit policy governing the Company s credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

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NOTE 18. SUPPLEMENTARY INFORMATION

A) Per Share Amounts

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

For the years ended December 31	**2004**	2003	2002
Weighted Average Common Shares Outstanding Basic	**460.4**	474.1	417.8
Effect of Stock Options and Other Dilutive Securities	**7.6**	5.6	4.8
Weighted Average Common Shares Outstanding Diluted	**468.0**	479.7	422.6

B) Net Change in Non-Cash Working Capital from Continuing Operations

For the years ended December 31	**2004**	2003	2002
Operating Activities			
Accounts receivable and accrued revenues	**$ 665**	$ (107)	$ (276)
Inventories	**14**	(241)	(64)
Accounts payable and accrued liabilities	**601**	(252)	(14)
Income taxes payable	**175**	32	(535)
	$ 1,455	$ (568)	$ (889)
Investing Activities			
Accounts payable and accrued liabilities	**$ (21)**	$ (113)	$ 195

C) Supplementary Cash Flow Information Continuing Operations

For the years ended December 31	**2004**	2003	2002
Interest Paid	**$ 401**	$ 284	$ 261
Income Taxes Paid (Received)	**$ 148**	$ (127)	$ 567

NOTE 19. COMMITMENTS AND CONTINGENCIES

Commitments

As at December 31, 2004	2005	2006	2007	2008	2009	Thereafter	**Total**
Pipeline Transportation	$ 297	$ 262	$ 237	$ 220	$ 182	$ 1,010	**$ 2,208**
Purchases of Goods and Services	121	23	14	9	3	5	**175**
Product Purchases	171	32	25	24	24	134	**410**
Operating Leases	42	43	41	36	29	152	**343**
Capital Commitments	190	41	22	4		38	**295**
Total	$ 821	$ 401	$ 339	$ 293	$ 238	$ 1,339	**$ 3,431**
Product Sales	$ 502	$ 56	$ 58	$ 61	$ 33	$ 275	**$ 985**

In addition to the above, the Company has made commitments related to its risk management program (see Note 17).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Contingencies

Legal Proceedings

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

Discontinued Merchant Energy Operations

In July 2003, the Company s indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), concluded a settlement with the U.S. Commodity Futures Trading Commission (CFTC) of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD s now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with Alberta Energy Company Ltd. in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC s order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. A motion by the Company and WD to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws.

Most of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and all of the New York lawsuits were consolidated in New York District Court by the plaintiff s application. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving only WD and several other companies unrelated to EnCana as the remaining defendants. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company s financial position, or whether there will be other proceedings arising out of these allegations.

Asset Retirement

The Company is responsible for the retirement of long-lived assets related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $611 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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Income Tax Matters

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that the Company operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

NOTE 20. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

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

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31	*Note*	**2004**	2003	2002
Net Earnings Canadian GAAP		**$ 3,513**	$ 2,360	$ 812
Less:				
Net Earnings From Discontinued Operations Canadian GAAP		**1,302**	218	146
Net Earnings From Continuing Operations Canadian GAAP		**2,211**	2,142	666
Increase (Decrease) under U.S. GAAP:				
Revenues, net of royalties	*B*	**243**	(101)	(174)
Operating	*B*	**(3)**		
Depreciation, depletion and amortization	*A,G*	**31**	14	(41)
Interest, net	*B*	**(41)**	70	126
Accretion of asset retirement obligation	*G*			13
Stock-based compensation	*C*	**(5)**	(1)	(3)
Income tax expense	*E,G*	**(73)**	7	21
Net Earnings From Continuing Operations U.S. GAAP		**2,363**	2,131	608
Net Earnings From Discontinued Operations U.S. GAAP		**1,370**	152	146
Net Earnings Before Change in Accounting Policy U.S. GAAP		**3,733**	2,283	754
Cumulative Effect of Change in Accounting Policy, net of tax	*G*		66	
Net Earnings U.S. GAAP		**$ 3,733**	$ 2,349	$ 754

Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP

Basic	**$ 8.11**	$ 4.82	$ 1.81
Diluted	**$ 7.98**	$ 4.76	$ 1.78
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP			
Basic	**$ 8.11**	$ 4.95	$ 1.81
Diluted	**$ 7.98**	$ 4.90	$ 1.78

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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CONSOLIDATED STATEMENT OF EARNINGS U.S. GAAP

For the years ended December 31	*Note*	**2004**	2003	2002
Revenues, Net of Royalties	*B*	**$ 12,053**	$ 9,585	$ 5,754
Expenses				
Production and mineral taxes		**311**	164	105
Transportation and selling		**499**	484	332
Operating	*B*	**1,353**	1,196	749
Purchased product		**4,276**	3,455	2,200
Depreciation, depletion and amortization	*A,G*	**2,371**	1,975	1,227
Administrative	*C*	**197**	173	121
Interest, net	*B*	**438**	213	160
Accretion of asset retirement obligation	*G*	**22**	17	
Foreign exchange gain		**(417)**	(598)	(11)
Stock-based compensation		**22**	19	
Gain on dispositions		**(113)**	(1)	(33)
Net Earnings Before Income Tax		**3,094**	2,488	904
Income tax expense	*E*	**731**	357	296
Net Earnings From Continuing Operations U.S. GAAP		**2,363**	2,131	608
Net Earnings From Discontinued Operations U.S. GAAP	*A,B*	**1,370**	152	146
Net Earnings Before Change in Accounting Policy U.S. GAAP		**3,733**	2,283	754
Cumulative Effect of Change in Accounting Policy, net of tax	*G*		66	
Net Earnings U.S. GAAP		**$ 3,733**	$ 2,349	$ 754
Net Earnings From Continuing Operations per Common Share U.S. GAAP				
Basic		**$ 5.13**	$ 4.49	$ 1.46
Diluted		**$ 5.05**	$ 4.44	$ 1.44
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 8.11**	$ 4.82	$ 1.81
Diluted		**$ 7.98**	$ 4.76	$ 1.78
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 8.11**	$ 4.95	$ 1.81
Diluted		**$ 7.98**	$ 4.90	$ 1.78

STATEMENT OF OTHER COMPREHENSIVE INCOME

For the years ended December 31	*Note*	**2004**	2003	2002
Net Earnings U.S. GAAP		**$ 3,733**	$ 2,349	$ 754
Change in Fair Value of Financial Instruments	*B,F*		4	(7)
Foreign Currency Translation Adjustment	*D*	**420**	1,046	136
Other			6	(6)
Other Comprehensive Income		$ **4,153**	$ 3,405	$ 877

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CONDENSED CONSOLIDATED BALANCE SHEET

As at December 31		**2004**		2003	
	Note	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets					
Current Assets	*A,B*	**$ 3,505**	**$ 3,497**	$ 2,616	$ 2,676
Property, Plant and Equipment, net	*A,G*	**23,140**	**23,044**	17,770	17,644
Investments and Other Assets	*B*	**334**	**330**	268	271
Risk Management	*B*	**87**	**87**		85
Assets of Discontinued Operations		**1,623**	**1,623**	1,545	1,545
Goodwill		**2,524**	**2,524**	1,911	1,911
		$ 31,213	**$ 31,105**	$ 24,110	$ 24,132
Liabilities and Shareholders Equity					
Current Liabilities	*A,B*	**$ 2,947**	**$ 2,942**	$ 2,072	$ 2,435
Long-Term Debt		**7,742**	**7,742**	6,088	6,088
Other Liabilities	*B*	**118**	**64**	21	8
Risk Management	*B*	**192**	**192**		10
Asset Retirement Obligation	*G*	**611**	**611**	383	383
Liabilities of Discontinued Operations	*A,B*	**102**	**102**	112	82
Future Income Taxes	*E,G*	**5,193**	**5,118**	4,156	4,054
		16,905	**16,771**	12,832	13,060
Share Capital	*C*	**5,299**	**5,316**	5,305	5,318
Share Options, net		**10**	**10**	55	55
Paid in Surplus		**28**	**28**	18	18
Retained Earnings		**7,935**	**7,955**	5,276	5,076
Foreign Currency Translation Adjustment	*D*	**1,036**		624	
Accumulated Other Comprehensive Income			**1,025**		605
		14,308	**14,334**	11,278	11,072
		$ 31,213	**$ 31,105**	$ 24,110	$ 24,132

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

As at December 31		**2004**		2003	
	Note	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets of Discontinued Operations	*A,B*	**$ 156**	**$ 159**	$ 781	$ 781
Liabilities of Discontinued Operations	*A,B*	**280**	**315**	405	500

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CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS U.S. GAAP

For the years ended December 31	**2004**	2003	2002
Operating Activities			
Net earnings from continuing operations	**$ 2,363**	$ 2,131	$ 608
Depreciation, depletion and amortization	**2,371**	1,975	1,227
Future income taxes	**164**	470	362
Unrealized (gain) loss on risk management	**(15)**	31	48
Unrealized foreign exchange gain	**(285)**	(545)	(23)
Accretion of asset retirement obligation	**22**	17	
Gain on dispositions	**(113)**	(1)	
Other	**98**	57	(163)
Cash flow from discontinued operations	**375**	324	360
Net change in other assets and liabilities	**(176)**	(84)	(17)
Net change in non-cash working capital from continuing operations	**1,455**	(568)	(889)
Net change in non-cash working capital from discontinued operations	**(1,668)**	497	104
Cash From Operating Activities	**$ 4,591**	$ 4,304	$ 1,617
Cash Used in Investing Activities	**$ (4,259)**	$ (3,729)	$ (2,595)
Cash From (Used in) Financing Activities	**$ 163**	$ (542)	$ 498

Notes:

A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves.

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

Effective January 1, 2004, the Canadian Accounting Standard s Board amended the Full Cost Accounting Guideline. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using estimated future prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices.

B) Derivative Instruments and Hedging

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative s fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue

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once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2004, under Canadian GAAP a $72 million deferred gain remains, of which a $1 million deferred loss has been classified in liabilities of discontinued operations.

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

Realized and unrealized gain/(loss) on derivatives related to:

For the years ended December 31	**2004**	2003	2002
Commodity Prices (Revenues, net of royalties)	**$ 76**	$ (205)	$ (174)
Interest and Currency Swaps (Interest, net)	**(29)**	70	126
Total Unrealized Gain (Loss)	**$ 47**	$ (135)	$ (48)
Amounts Allocated to Continuing Operations	**$ 15**	$ (31)	$ (48)
Amounts Allocated to Discontinued Operations	**32**	(104)	
	$ 47	$ (135)	$ (48)

As at December 31, 2004, it is estimated that over the following 12 months, $3 million ($2 million, net of tax) will be reclassified into net earnings from other comprehensive income.

C) Stock-based Compensation CPL Reorganization

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financial statements, which would be the same adjustment under U.S. GAAP, see Note 15.

Under Financial Accounting Standards Board (FASB) Interpretation No. 44 Accounting for Certain Transactions involving Stock Compensation , compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of Canadian Pacific Ltd., an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana as described in Note 15. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) Foreign Currency Translation Adjustments

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

E) Future Income Taxes

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

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

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

For the years ended December 31	**2004**	2003	2002
Using Canadian GAAP:			
Net Earnings Before Income Tax	**$ 2,869**	$ 2,506	$ 983
Canadian Statutory Rate	**39.1%**	41.0%	42.3%
Expected Income Tax	**1,123**	1,026	416
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**192**	231	147
Canadian resource allowance	**(246)**	(258)	(200)
Canadian resource allowance on unrealized risk management losses	**(10)**		
Statutory and other rate differences	**(55)**	(45)	(35)
Effect of tax rate reductions	**(109)**	(359)	(20)
Non-taxable capital gains	**(91)**	(119)	
Previously unrecognized capital losses	**17**	(119)	
Tax basis retained on dispositions	**(179)**		
Large corporations tax	**24**	27	23
Other	**(8)**	(20)	(14)
	658	364	317
U.S. GAAP Adjustments to Net Earnings Before Income Tax	**225**	(18)	(79)
Expected Income Tax	**88**	(7)	(33)
Other	**(15)**		12
	73	(7)	(21)
Income Tax U.S. GAAP	**$ 731**	$ 357	$ 296
Effective Tax Rate	**23.6%**	14.3%	32.7%

The net future income tax liability is comprised of:

As at December 31	**2004**	2003
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,436**	$ 3,152
Timing of partnership items	**1,005**	1,162
Future Tax Assets		
Net operating losses carried forward	**(103)**	(99)
Other	**(220)**	(161)
Net Future Income Tax Liability	**$ 5,118**	$ 4,054

F) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of FAS 133. At December 31, 2004, accumulated other comprehensive income related to these items was a loss of $9 million, net of tax.

G) Asset Retirement Obligation

In 2003, the Company early adopted the Canadian accounting standard for asset retirement obligations, as outlined in the CICA handbook section 3110. This standard is equivalent to U.S. FAS

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143 Accounting for Asset Retirement Obligations , which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligation, however a difference is created in how the transition amounts are disclosed.

U.S. GAAP requires the cumulative impact of a change in an accounting policy be presented in the current year Consolidated Statement of Earnings and prior periods not be restated. The following table illustrates the pro forma impact on the Company s financial results under U.S. GAAP if the prior periods had been restated:

For the year ended December 31	As Reported	Change	As Restated
2002 Consolidated Statement of Earnings			
Net Earnings	$ 754	$ 34	$ 788
Net Earnings per Common Share Diluted	$ 1.78	$ 0.08	$ 1.86

H) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

I) Recent Accounting Pronouncements

During 2004, the following new standards were issued:

Share-Based Payment

In 2004, FASB issued revised FAS 123 Share-Based Payment . This amended statement eliminates the alternative to use Accounting Principles Board (APB) Opinion No. 25 s intrinsic value method of accounting, as was provided in the originally issued Statement 123. As a result, public entities are required to use the grant-date fair value of the award in measuring the cost of employee services received in exchange for an equity award of equity instruments. Compensation cost is required to be recognized over the requisite service period. For liability awards, entities are required to re-measure the fair value of the award at each reporting date up until the settlement date. Changes in fair value of liability awards during the requisite service period are required to be recognized as compensation cost over the vesting period. Compensation cost is not recognized for equity instruments for which employees do not render the requisite service. This amended statement is effective the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is currently assessing the impact of this amendment.

Exchange of Non-monetary Assets

In 2004, FASB issued FAS 153 Exchange of Non-monetary Assets . This statement is an amendment of APB Opinion No. 29 Accounting for Non-monetary Transactions . Based on the guidance in APB Opinion No. 29, exchanges of non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion

No. 29 s exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges which occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Earlier application is permitted for non-monetary asset exchanges which occur in fiscal periods beginning after the issue date of this statement. Currently, this statement does not have an impact on EnCana;

however, this may result in a future impact to the Company if EnCana enters into any non-monetary asset exchanges.

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.1 and 99.2 to this Annual Report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant s fiscal year ended December 31, 2004, an evaluation of the effectiveness of the registrant s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) was carried out by the registrant s principal executive officer and principal financial officer. Based upon that evaluation, the registrant s principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant s disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant s management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while the registrant s principal executive officer and principal financial officer believe that the registrant s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2004, there were no changes in the registrant s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrant s internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The registrant s board of directors has determined that Jane L. Peverett, a member of the registrant s audit committee, qualifies as an audit committee financial expert (as such term is defined in Form 40-F).

Code of Ethics.

The registrant has adopted a code of ethics (as that term is defined in Form 40-F), entitled the Business Conduct and Ethics Practice (the Code of Ethics), that applies to its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions (together, the Financial Supervisors).

The Code of Ethics is available for viewing on the registrant s website at www.encana.com.

Since the adoption of the Code of Ethics, there have not been any amendments to the Code of Ethics or waivers, including implicit waivers, from any provision of the Code of Ethics.

Principal Accountant Fees and Services.

The required disclosure is included under the heading Audit Committee Information-External Auditor Service Fees in the registrant s Annual Information Form for the fiscal year ended December 31, 2004, filed as part of this Annual Report on Form 40-F.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading Audit Committee Information-Pre-Approval Policies and Procedures in the registrant s Annual Information Form for the fiscal year ended December 31, 2004, filed as part of this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements.

The required disclosure is included under the heading Off-Balance Sheet Arrangements in the registrant s Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2004, filed as part of this Annual Report on Form 40-F.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading Contractual Obligations and Contingencies in the registrant s Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2004, filed as part of this Annual Report on Form 40-F.

Identification of the Audit Committee.

The registrant has a separately-designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, William R. Fatt, Barry W. Harrison, Dale A. Lucas, Jane L. Peverett, James M. Stanford and David P. O Brien (ex officio).

Disclosure Pursuant to the Requirements of the New York Stock Exchange.

Presiding Director at Meetings of Non-Management Directors

The registrant schedules regular executive sessions in which the registrant s non-management directors (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. Mr. David P. O Brien serves as the presiding director (the Presiding Director) at such sessions. Each of the registrant s non-management directors is unrelated as such term is used in the rules of the Toronto Stock Exchange.

Communication with Non-Management Directors

Shareholders may send communications to the registrant s non-management directors by writing to the Presiding Director, c/o Kerry D. Dyte, General Counsel and Corporate Secretary, EnCana Corporation, 1800, 855 2nd Street S.W., Calgary, Alberta, Canada, T2P 2S5. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the board of directors as appropriate.

Corporate Governance Guidelines

According to Section 303A.09 of the NYSE Listed Company Manual, a listed company must adopt and disclose a set of corporate governance guidelines with respect to specified topics. Such guidelines are required to be posted on the listed company s website. The registrant operates under corporate governance principles that are consistent with the requirements of Section 303A.09 of the NYSE Listed Company Manual, and which are described under the heading Statement of Corporate Governance Practices in the registrant s Information Circular in connection with its 2005 Annual Meeting. However, the registrant has not codified its corporate governance principles into formal guidelines in order to post them on its website.

Board Committee Mandates

The Mandates of the registrant s audit committee, human resources and compensation committee, and nominating and corporate governance committee are each available for viewing on the registrant s website at www.encana.com, and are available in print to any shareholder who requests them. Requests for copies of these documents should be made by contacting: Kerry D. Dyte, General Counsel and Corporate Secretary, EnCana Corporation, 1800, 855-2nd Street S.W., P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5. Alternatively, requests for these documents may be made by contacting the registrant s Corporate Development Department at (403) 645-2000 (Fax: (403) 645-4617).

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking.

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

B. Consent to Service of Process.

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

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

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 25, 2005.

EnCana Corporation

By: /s/ Thomas G. Hinton
Name: Thomas G. Hinton
Title: Treasurer

By: /s/ Gerald T. Ince
Name: Gerald T. Ince
Title: Assistant Treasurer

EXHIBIT INDEX

Exhibit	Description
99.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.3	Section 1350 Certification of Chief Executive Officer
99.4	Section 1350 Certification of Chief Financial Officer
99.5	Consent of PricewaterhouseCoopers LLP
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of Netherland, Sewell & Associates, Inc.
99.8	Consent of DeGolyer and MacNaughton
99.9	Consent of Gilbert Laustsen Jung Associates Ltd.