ENCANA CORP
Form 40-F
February 17, 2006

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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

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

For the fiscal year ended December 31, 2005

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:

ý Annual Information Form ý 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: **859,253,318 common shares**

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 ý

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 ý   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. 333-124218, 333-85598 and 333-13956) 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, 2005;

(b) Management s Discussion and Analysis for the fiscal year ended December 31, 2005; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2005 *(Note 19 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

ANNUAL INFORMATION FORM

February 17, 2006

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2005. 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.

Unless otherwise specified, all dollar amounts are expressed in United States ("U.S.") dollars and all references to "dollars" or to "$" are to U.S. dollars and all references to "C$" are to Canadian dollars. All production and reserves information is presented on an after royalties basis consistent with U.S. protocol reporting.

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.

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NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements or information (collectively referred to in this note as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "projected", "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: oilsands strategy and the effect of this strategy, timing and completion of the sale of the Ecuador assets, the Chinook heavy oil discovery, the natural gas storage business and the Entrega Pipeline, plans to import diluent, 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 and new plant construction, the timing of completion of the environmental assessment on the Suffield Block, the timing of completion of the Foster Creek and Christina Lake expansions, the completion of waterflood implementation at Pelican Lake, government royalty rates, the results of the U.S. Bureau of Land Management decision regarding the Jonah area, the potential for natural gas resource play development on the Foix permit lands, reserves estimates, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and disposition plans, including farmout plans, the timing of acquisitions, net cash flows, geographical expansion and plans for seismic 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 and assumptions regarding oil and natural gas prices, assumptions based upon EnCana's current guidance, 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, risks associated with technology, 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 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.

EnCana has disclosed proved reserve quantities using the standards contained in 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" ("SFAS 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 value equivalency at the well head.

CORPORATE STRUCTURE

Name and Incorporation

EnCana Corporation is incorporated under the *Canada Business Corporations Act* ("CBCA"). Its executive and registered office is located at 1800, 855 - 2nd Street S.W., Calgary, Alberta, Canada T2P 2S5.

EnCana was formed through the business combination (the "Merger"), on April 5, 2002, of Alberta Energy Company Ltd. ("AEC") and PanCanadian Energy Corporation ("PanCanadian").

On April 27, 2005, EnCana amended its articles to effect a two-for-one share split.

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 as at December 31, 2005. Each of these subsidiaries and partnerships had total assets that exceeded 10 percent of the total consolidated assets of EnCana or revenues that exceeded 10 percent of the total consolidated revenues of EnCana as at and for the year ended December 31, 2005:

Subsidiaries & Partnerships	Percentage Owned[(1)]	Jurisdiction of Incorporation, Continuance or Formation
EnCana Western Resources Ltd.[(2)]	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
AECO Gas Storage Partnership	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Formerly EnCana West Ltd. (name was changed to EnCana Western Resources Ltd. on December 21, 2005). EnCana Western Resources Ltd. was wound up into EnCana Corporation on January 2, 2006.

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, 2005.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of North America's leading natural gas producers, is among the largest holders of natural gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana pursues growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average long-term decline rates and very long producing lives compared to conventional plays. The Corporation is also engaged in select exploration and production activities internationally.

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 and 2005, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. In focusing its portfolio of assets, the Corporation completed a number of acquisitions and dispositions during the past three years. A portion of the disposition proceeds were used to fund EnCana's normal course issuer bid program (the "Bid"). In 2005, EnCana purchased approximately 55 million shares under the Bid for approximately $1.9 billion. For further information, refer to "Market For Securities" in this annual information form.

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. In this section, all disposition proceeds are provided on a before tax basis unless otherwise noted.

Upstream

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

2005 Projects:

In November 2005, EnCana announced plans to examine a number of proposals from other companies, including major multinationals, integrated producers and international oil companies, who are interested in participating in the development of EnCana's oilsands assets. The Corporation is considering creative business opportunities which may include equity investments, farm-ins, asset swaps, long-term bitumen supply agreements and the integration of upstream and downstream assets. These initiatives are expected to help EnCana enhance the value and accelerate the development of its oilsands resources.

2005 Acquisitions:

In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million.

In the fourth quarter of 2005, a subsidiary of EnCana completed the purchase of approximately 24,000 total net acres (2,000 net developed acres) of development land in the Fort Worth Basin for approximately $178 million. The purchase included properties producing approximately 16 million cubic feet per day of natural gas.

2005 Dispositions:

In May 2005, subsidiaries of EnCana completed the sale of the Corporation's Gulf of Mexico assets for approximately $2.1 billion ($1.5 billion after taxes and other adjustments). The Gulf of Mexico assets included the Corporation's interests in the Tahiti, Tonga, Sturgis, Sawtooth, Jack and St. Malo discoveries. EnCana had an average 40 percent interest in 239 exploration blocks covering approximately 1.4 million gross acres in the Gulf of Mexico.

In June 2005, EnCana completed the sale of western Canadian conventional oil and natural gas assets producing approximately 6,400 barrels of oil equivalent per day for approximately $321 million.

In addition to the transactions completed in 2005, EnCana has a number of dispositions in progress. In October 2004, EnCana announced its intention to dispose of its Ecuador assets. The Ecuador assets include interests in five Oriente Basin blocks (Tarapoa Block, Block 14, Block 17, Shiripuno Block and EnCana's economic interest in relation to Block 15) and a 36.3 percent interest in the Oleoducto de Crudos Pesados ("OCP") pipeline. In September 2005, the Corporation reached an agreement to sell all of its interests in Ecuador for approximately $1.42 billion. The effective date of the sale is July 1, 2005. The sale is subject to approval by the Government of Ecuador, regulatory approvals and other closing conditions. EnCana expects the sale to close in the first quarter of 2006. Ecuador is reported as discontinued operations for financial reporting purposes.

In November 2005, the Corporation reached an agreement to sell its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. The sale is subject to regulatory approvals and other closing conditions and is expected to close in the first quarter of 2006.

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. At the time of the acquisition, Tom Brown had assets 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 the Fort Worth Basin of north Texas for approximately $251 million.

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 order to facilitate the transaction, the Corporation purchased the 46.7 percent interest of its partner for approximately $253 million and then sold the 100 percent interest in Petrovera for a total of approximately $540 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.

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

In December 2004, a subsidiary of EnCana completed 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 central North Sea.

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, a subsidiary of EnCana exchanged its non-operated interest in the Llano discovery in the Gulf of Mexico with a third party 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 2003, in two separate transactions, EnCana 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 approximately $1 billion. Syncrude operates a facility in northeast Alberta which produces crude oil from oilsands.

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 market optimization activities and remaining midstream assets. The division was involved in a number of strategic projects over the past three years. In conjunction with the Corporation's resource play focus, EnCana has divested a number of its midstream assets and is currently in the process of divesting the majority of its remaining midstream assets. As a result, Midstream is reported as discontinued operations for financial reporting purposes.

2005 Projects:

In September and October 2005, a wholly owned partnership of EnCana signed agreements with Methanex Corporation ("Methanex") and Provident Energy Ltd. ("Provident") under which Methanex will provide terminalling services to EnCana at Methanex's terminal facilities at Kitimat, British Columbia, and Provident will provide terminalling services to EnCana at Provident's terminal facilities at Redwater, Alberta. EnCana plans to import up to 25,000 barrels per day of offshore diluent to help transport its growing oilsands production in northeast Alberta to markets in the U.S.

In December 2005, Entrega Gas Pipeline LLC ("Entrega"), an affiliate of EnCana Oil & Gas (USA) Inc., completed material portions of the construction of the first segment of its U.S. Federal Energy Regulatory Commission ("FERC") regulated pipeline project (the "Entrega Pipeline"), from Meeker Hub, Colorado to Wamsutter, Wyoming. This first segment of the pipeline is expected to be in service in February 2006, and has a capacity of up to approximately 750 million cubic feet per day.

2005 Dispositions:

In December 2005, EnCana and certain affiliates completed the sale of substantially all of their natural gas liquids processing business for approximately $625 million. The divested assets included interests in four NGLs extraction plants at Empress, Alberta, storage and fractionation assets in Saskatchewan, eastern Canada and the U.S. and EnCana's 100 percent interest in Kinetic Resources, an NGLs marketer.

In June 2005, EnCana announced plans to divest of its natural gas storage business. EnCana has North America's largest independent natural gas storage network, with approximately 174 billion cubic feet of working gas capacity at five facilities in Alberta, California and Oklahoma. EnCana plans to retain ownership of the Hythe facility, which has a capacity of approximately 10 billion cubic feet. The Corporation expects the sale to close in the second quarter of 2006.

In November 2005, EnCana entered into an agreement to sell Entrega to the Kinder Morgan-Sempra Pipelines & Storage project group ("KMP"). The sale is contingent upon the successful completion of certain conditions related to exit capacity from the U.S. Rockies production areas. The sale is anticipated to close in the first quarter of 2006 and will include all of the assets of the FERC-regulated company.

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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.

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. Kingston CoGen owns a 110 megawatt cogeneration plant in Kingston, Ontario.

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

2003 Projects:

In October 2003, the first phase of the Countess natural gas storage facility became operational, 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. In 2005, EnCana received Alberta Energy and Utilities Board approval for delta pressuring, which enabled the utilization of the full design capacity of approximately 40 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 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.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2005.

UPSTREAM

The vast majority of EnCana's Upstream operations are located in Canada, the U.S. and Ecuador. Frontier and International New Ventures is pursuing opportunities off the East Coast of Canada, in Northern Canada, Chad, Brazil, the Middle East, Greenland and France.

At December 31, 2005, EnCana had net proved reserves of approximately 11.8 trillion cubic feet of natural gas and 1.1 billion barrels of crude oil, bitumen and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 61 percent of total natural gas reserves, approximately 76 percent of crude oil and NGLs reserves excluding bitumen and approximately 16 percent of bitumen 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 24 million gross acres (approximately 22 million net acres, of which approximately 13 million net acres are undeveloped). The mineral rights on approximately one third of the total net acreage is 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.

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 oilsands projects at Foster Creek, Christina Lake and Borealis. Three key resource plays are located in the Canadian Plains Region: (i) Shallow Gas in southern Alberta; (ii) Coalbed Methane ("CBM") developments in southern and central Alberta; and (iii) Steam-Assisted Gravity Drainage ("SAGD") operations at Foster Creek.

In 2005, in the Canadian Plains Region, EnCana had core capital expenditures of approximately $2,208 million and drilled approximately 3,411 net wells. EnCana's 2006 core capital investment in the Canadian Plains Region is projected to be approximately $1,800 to $1,900 million, which includes the drilling of approximately 3,100 to 3,200 net wells.

The following table summarizes landholdings for the Canadian Plains Region as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	904	889	125	119	1,029	1,008	98%
Brooks	1,218	1,193	164	153	1,382	1,346	97%
Chinook	1,055	1,030	364	346	1,419	1,376	97%
Central Parkland	797	649	1,367	1,271	2,164	1,920	89%
Foster Creek	8	8	51	51	59	59	100%
Christina Lake	1	1	44	44	45	45	100%
Borealis			152	152	152	152	100%
Weyburn	86	75	604	597	690	672	97%
Other	2,712	2,391	3,869	3,601	6,581	5,992	91%
Canadian Plains Total	6,781	6,236	6,740	6,334	13,521	12,570	93%

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

Production (annual average)	Natural Gas (MMcf/d) 2005	2004	Crude Oil and NGLs (bbls/d) 2005	2004	Total Production (MMcfe/d) 2005	2004
Suffield	243	241	20,756	26,706	368	401
Brooks	490	474	13,220	15,542	569	568
Chinook	276	257	2,975	4,406	294	283
Central Parkland	59	33	1,505	2,238	68	46
Foster Creek			29,019	28,774	174	173
Christina Lake			5,360	4,364	32	26
Weyburn			13,562	14,200	81	85
Other	280	269	23,183	30,690	419	454
Canadian Plains Total	1,348	1,274	109,580	126,920	2,005	2,036

Notes:

(1) The Shallow Gas key resource play, located mainly in the Suffield and Brooks areas, had 2005 average production of approximately 625 million cubic feet per day (592 million cubic feet per day in 2004).

(2) The CBM key resource play, located in the Chinook and Central Parkland areas, had 2005 average production of approximately 57 million cubic feet per day (17 million cubic feet per day in 2004).

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	8,324	8,284	708	706	9,032	8,990
Brooks	10,034	9,599	280	276	10,314	9,875
Chinook	4,515	4,412	149	140	4,664	4,552
Central Parkland	886	643	29	12	915	655
Foster Creek			55	55	55	55
Christina Lake			5	5	5	5
Weyburn			687	430	687	430
Other	2,133	1,763	1,150	764	3,283	2,527
Canadian Plains Total	25,892	24,701	3,063	2,388	28,955	27,089

Notes:

(1) At December 31, 2005, the Shallow Gas key resource play had 17,038 gross producing gas wells (16,556 net gas wells).

(2) At December 31, 2005, the CBM key resource play had 1,651 gross producing gas wells (1,507 net gas wells).

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 key 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. In 2003, a portion of the Suffield Block was designated as a National Wildlife Area ("NWA") and since that time no further wells have been drilled in the NWA. Prior to drilling any further infill shallow gas wells in the NWA, EnCana must complete an environmental assessment under the Canadian Environmental Assessment Act. EnCana expects to complete the assessment in 2006.

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 key 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 key resource play. The CBM development in the Horseshoe Canyon formation is located within the Chinook area and covers approximately 700,000 acres. In 2005, EnCana drilled approximately 656 net CBM wells on its project area on the Palliser Block, increasing production to approximately 57 million cubic feet per day at year-end.

Central Parkland

The Central Parkland area, located immediately north of the Chinook area, contains the northern extension of EnCana's Horseshoe Canyon CBM key resource play. EnCana holds a combination of fee and crown lands in the area. In 2005, EnCana drilled approximately 428 net CBM wells in the area, increasing production to approximately 27 million cubic feet per day at year-end. In December 2005, EnCana purchased approximately 218,000 net acres of land in the area for prospective CBM development in the Mannville formation, for approximately $138 million.

Oilsands

EnCana has two primary SAGD operations in the Athabasca oilsands region of northeast Alberta: (i) Foster Creek; and (ii) Christina Lake. EnCana has also identified another potential SAGD development opportunity in a third location, Borealis, located north of Fort McMurray.

In November 2005, EnCana announced plans to examine a number of proposals from other companies that would enable the Corporation to accelerate the development of its oilsands resources. EnCana is considering a number of initiatives, which may include equity investments, farm-ins, asset swaps, long-term bitumen supply agreements and the integration of upstream and downstream assets. The Corporation holds approximately 1.2 million net acres within the Athabasca oilsands area, which includes the ownership of approximately 685,000 net acres and the exclusive rights to lease an additional 557,000 net acres on the Cold Lake Air Weapons Range.

Foster Creek

EnCana has a 100 percent working interest in Foster Creek, one of the Corporation's 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 thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology.

Crude oil production at Foster Creek in 2005 averaged approximately 29,000 barrels per day. In the fourth quarter of 2005, EnCana completed the first stage of an expansion which added an additional 10,000 barrels per day of capacity. The second stage of the expansion, which is projected to add an additional 20,000 barrels per day of capacity, is expected to be completed in late 2006. The expansion is anticipated to increase EnCana's productive capacity at Foster Creek to 60,000 barrels per day.

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 alternate methods of artificial lift where EnCana is operating alternative pump designs that are expected to enable the Corporation to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital costs. At

December 31, 2005, EnCana had 32 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to continue to utilize this technology on new SAGD wells.

Another focus area is to reduce the reliance on steam in bitumen production. EnCana has piloted two technologies using solvents as part of the extraction process. The Vapex process, which uses solvent in place of steam, was piloted at Foster Creek from 2002 to 2005. The outcome of the pilot is currently under review. The Solvent Aided Process ("SAP") is discussed in the Christina Lake section below.

EnCana continues to operate its 80 megawatt, natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. 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 2005, EnCana added two well pairs which increased average annual production to approximately 5,400 barrels per day. The Corporation recently approved an expansion which is expected to increase production capacity to approximately 18,000 barrels per day by early 2008.

EnCana continues to pilot SAP, which commenced in 2004, at Christina Lake. This process mixes a small amount of solvent with steam to enhance recovery.

Borealis

EnCana has a 100 percent working interest in approximately 152,000 acres in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. At December 31, 2005, the Corporation had drilled approximately 135 delineation wells in the area. In 2006, EnCana plans to continue its stratigraphic well program to further delineate these lands. EnCana began acquiring land in the Borealis area in 1999.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery ("EOR") area of the field with a carbon dioxide ("CO_2") miscible flood project. In 2005, EnCana continued its infill drilling program and drilled 45 new wells in the EOR area. This program ensures optimal coverage of areas currently within the EOR area. Eight additional patterns, or well groupings, were put into operation in the CO_2 miscible flood development in 2005. As of December 31, 2005, there were 44 patterns on stream out of a planned total of 75 patterns. EnCana has secured additional volumes of CO_2 by expanding the Corporation's existing contract with the Dakota Gasification Company. This allows the Corporation to further expand its CO_2 injection program.

Canadian Foothills Region

The Canadian Foothills Region includes EnCana's natural gas and crude oil exploration, development and production activities in British Columbia and northern Alberta. Three key resource plays are located in the Canadian Foothills Region: (i) Greater Sierra; (ii) Cutbank Ridge; and (iii) Pelican Lake.

In 2005, in the Canadian Foothills Region, EnCana had core capital expenditures of approximately $1,885 million and drilled approximately 627 net wells. EnCana's 2006 core capital investment in the Canadian Foothills Region is projected to be approximately $1,700 to $1,800 million, which includes the drilling of approximately 575 to 625 net wells.

The following table summarizes landholdings for the Canadian Foothills Region as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	545	488	2,582	2,319	3,127	2,807	90%
Cutbank Ridge	153	127	858	768	1,011	895	89%
Pelican Lake	84	84	133	133	217	217	100%
Bighorn	272	156	914	584	1,186	740	62%
Sexsmith/Hythe/ Saddle Hills	282	179	209	155	491	334	68%
Cold Lake Air Weapons Range	384	363	471	467	855	830	97%
Other	1,096	907	2,734	2,296	3,830	3,203	84%
Canadian Foothills Total	2,816	2,304	7,901	6,722	10,717	9,026	84%

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

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2005	2004	2005	2004	2005	2004
Greater Sierra	219	230	793	632	224	234
Cutbank Ridge	92	40			92	40
Pelican Lake	4	7	25,752	18,900	159	120
Bighorn	56	47	867	865	61	52
Sexsmith/Hythe/Saddle Hills	99	110	1,989	2,785	111	127
Cold Lake Air Weapons Range	129	163			129	163
Other	178	239	3,936	4,284	201	265
Canadian Foothills Total	777	836	33,337	27,466	977	1,001

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	705	664	3	3	708	667
Cutbank Ridge	213	191			213	191
Pelican Lake	13	13	507	507	520	520
Bighorn	123	73	5	2	128	75
Sexsmith/Hythe/Saddle Hills	291	228	6	3	297	231
Cold Lake Air Weapons Range	623	599			623	599
Other	1,740	1,570	264	158	2,004	1,728
Canadian Foothills Total	3,708	3,338	785	673	4,493	4,011

The following describes EnCana's major producing areas or activities in the Canadian Foothills 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 219 million cubic feet per day in 2005. Sales volumes decreased in 2005 compared to 2004 due to the timing and pace of development drilling and delays in well tie-ins as a result of weather issues in the spring and summer of 2005. EnCana is selectively farming out a small portion of its Greater Sierra land position to third parties. The farmouts provide EnCana with additional capital and allow the Corporation to add production volumes at a relatively low cost.

As at December 31, 2005, EnCana held an average 99 percent interest in 13 production facilities in the area that were capable of processing approximately 486 million cubic feet per day of natural gas. EnCana also holds a 100 percent interest in the Ekwan pipeline which has a capacity of approximately 400 million cubic feet per day and transports natural gas from northeast British Columbia to Alberta. Pipeline throughput was approximately 115 million cubic feet per day in 2005.

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 2005, EnCana drilled approximately 135 net natural gas wells at Cutbank Ridge and increased production to approximately 142 million cubic feet per day of natural gas by year-end.

In April 2005, EnCana began production from the Cutbank Doig natural gas discovery, located stratigraphically below the Cutbank Ridge resource play. The initial well into this conventional discovery was drilled in 2004. In order to facilitate production from Cutbank Ridge, including the recent discovery at Cutbank Doig, EnCana is constructing the Steeprock natural gas processing plant located approximately 50 kilometres south of Dawson Creek, British Columbia. The plant is expected to have a capacity of approximately 198 million cubic feet per day. EnCana anticipates that the plant will be completed in the fourth quarter of 2006.

Pelican Lake

Pelican Lake is another of EnCana's key resource plays producing crude oil in north-central Alberta. In 2005, EnCana continued to expand its waterflood program at Pelican Lake, which has increased the recovery of crude oil in the area. The success of the waterflood program at Pelican Lake increased 2005 crude oil production by approximately 36 percent compared to 2004. In 2006, EnCana expects to complete its waterflood implementation throughout the field and expand its polymer flood pilot project to further improve performance. In 2006, EnCana expects the Pelican Lake project to reach payout status, which will result in an increase in the government royalty rate from one percent to approximately 21 percent. 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.

Bighorn

The Bighorn area in west central Alberta is EnCana's newest natural gas resource play, focusing on exploitation of multi-zone stacked Cretaceous sands in the Deep Basin. EnCana has an average working interest of approximately 62 percent in approximately 1.2 million gross acres (740,000 net acres) of land in the Bighorn area. The primary producing properties in Bighorn are Berland, Wild River, Resthaven and Kakwa. In 2005, EnCana drilled approximately 51 net wells in the area and production averaged approximately 56 million cubic feet per day of sweet natural gas. Wet weather in the spring and summer of 2005 delayed drilling and well tie-ins, limiting production growth for the year. Also in 2005, EnCana expanded an existing natural gas processing plant to a capacity of 20 million cubic feet per day and commenced construction of a new 100 million cubic feet per day gas plant in the Resthaven area. At Wild River, a facility expansion to increase processing capacity to approximately 30 million cubic feet per day was initiated.

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 275-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 owned and operated compression facilities. In 2005, 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 22 million cubic feet per day (eight million cubic feet per day in 2004). No additional wells were shut-in during 2005. The Alberta Government's Department of Energy is providing financial assistance in the form of a royalty credit, which is equal to approximately 50 percent of the cash flow lost as a result of the shut-in wells in the area.

United States

EnCana's operations in the U.S. are focused on exploiting long-life unconventional natural gas formations in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado and the East Texas, Fort Worth and Maverick Basins in Texas. The Corporation also has landholdings in the Columbia River basin in Washington State, as well as interests in natural gas gathering and processing assets. The majority of the production in the U.S. is from the following four key resource plays: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth.

In 2005, EnCana had core capital expenditures in the U.S. of approximately $1,982 million and drilled approximately 617 net wells. EnCana's 2006 core capital investment in the U.S. is projected to be approximately $2,100 to $2,200 million, which includes the drilling of approximately 830 to 860 net wells.

The following table summarizes EnCana's landholdings in the United States as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Jonah	11	9	10	10	21	19	90%
Piceance	233	220	749	704	982	924	94%
East Texas	73	46	428	294	501	340	68%
Fort Worth	37	31	206	174	243	205	84%
Maverick Basin	3	3	468	325	471	328	70%
Columbia River Basin			848	837	848	837	99%
Other	463	222	1,930	1,674	2,393	1,896	79%
United States Total	820	531	4,639	4,018	5,459	4,549	83%

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

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2005	2004	2005	2004	2005	2004
Jonah	435	389	3,939	3,294	459	409
Piceance	307	261	2,965	3,074	325	279
East Texas	90	50	304	167	92	51
Fort Worth	70	27	345	233	72	28
Other	193	142	6,337	6,037	230	179
United States Total	1,095	869	13,890	12,805	1,178	946

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Jonah	511	457			511	457
Piceance	2,410	2,124	5	2	2,415	2,126
East Texas	701	356	10	4	711	360
Fort Worth	501	447	8	6	509	453
Other	2,605	1,873	26	8	2,631	1,881
United States Total	6,728	5,257	49	20	6,777	5,277

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 the Green River Basin in southwest Wyoming. The Jonah key resource play represents EnCana's initial entry into the U.S. Rockies region. Since EnCana's initial acquisition in the area in 2000, production has approximately quadrupled 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.

On January 13, 2006, the U.S. Bureau of Land Management released the Final Environmental Impact Statement covering future development in the Jonah area. A Record of Decision is expected at the conclusion of the public comment period. Approval is expected to allow the drilling of approximately 1,500 additional wells, and is expected to allow a change to vertical drilling which has the potential to reduce future drilling costs. In 2005, EnCana drilled approximately 104 net wells in the Jonah area.

Piceance

The Piceance Basin in northwest Colorado is one of EnCana's key natural gas resource plays. The 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. In 2005, EnCana drilled approximately 266 net wells in the basin.

East Texas

EnCana produces natural gas and associated NGLs 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 2005, EnCana drilled approximately 84 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. Since entering the area in 2003, the Corporation has assembled a significant land position in the Barnett Shale play in this basin. 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. In the fourth quarter of 2005, a subsidiary of EnCana completed the purchase of additional development land and producing properties in the basin. EnCana drilled approximately 59 net wells in the basin in 2005.

Maverick Basin

In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million. In 2006, EnCana plans to apply its expertise in horizontal drilling and completions technology to test the multi-zone potential of gas-bearing formations in the Maverick Basin.

Columbia River Basin

EnCana holds approximately 848,000 gross acres (837,000 net acres) in the Columbia River Basin in Washington State. This sedimentary basin is covered with 5,000 to 15,000 feet of volcanic basalt and as a result it is relatively under-explored. EnCana believes that there may be potential to employ new drilling technology to cost effectively explore and develop the basin. The Corporation has entered into an agreement with an industry partner who will participate in the initial funding of the exploration program in return for a portion of EnCana's acreage in the area. EnCana is currently drilling its first two exploration wells in the basin.

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, Colorado 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.

Frontier and International New Ventures

EnCana invests a small portion of its capital in high potential exploration beyond its core geographic areas, primarily offshore the East Coast of Canada, in Northern Canada, Chad, Brazil, the Middle East, Greenland and France. In 2005, EnCana's Frontier and International New Ventures division had core capital expenditures of approximately $125 million and drilled approximately three net wells. EnCana's 2006 core capital investment in the Frontier and International New Ventures region is projected to be approximately $100 million, which includes the drilling of approximately 10 net wells.

East Coast of Canada

At December 31, 2005, EnCana held an interest in approximately 3.9 million gross acres (2.4 million net acres) offshore the East Coast of Canada, which includes Nova Scotia and Newfoundland & Labrador. EnCana operates 13 of its 20 licenses in these areas and has an average working interest of approximately 57 percent.

EnCana is the operator of the Deep Panuke field, located offshore Nova Scotia, and had an approximate 85 percent working interest at December 31, 2005. EnCana continues to examine the potential economic viability of the Deep Panuke project. In late 2005 and early 2006, EnCana participated in the drilling of an exploration well, Dominion J-14, plus a sidetrack well, in the Grand Pre license in an attempt to extend the northeast boundary of the Deep Panuke field. The wells, which were abandoned in January 2006, failed to discover commercial quantities of hydrocarbons. Pursuant to a farmout agreement signed in November 2005, EnCana expects to transfer an approximate 25 percent working interest in the Grand Pre license to its partner after the final drilling costs for the Dominion J-14 well are determined.

Northern Canada

EnCana has non-operated working interests in northern Canada which include 35 Significant Discovery Licenses and three Production Licenses in Nunavut, the Northwest Territories and the Yukon Territory.

In addition, EnCana is the operator and has a working interest in one Exploration License in the Northwest Territories which encompasses approximately 133,000 gross acres (50,000 net acres). In 2005, EnCana drilled one successful well to appraise a natural gas discovery made at Umiak in the Mackenzie Delta area in 2004. A Significant Discovery License Application has been made to the relevant regulatory bodies to indefinitely continue approximately 26,000 gross acres (10,000 net acres) of the exploration license associated with the Umiak field discovery. In October 2005, EnCana relinquished approximately 79,000 gross acres in the area.

Chad

EnCana's onshore exploration operations in Chad are based out of its subsidiary's office in N'Djamena. At December 31, 2005, EnCana had a 50 percent working interest in Permit H comprising approximately 54 million gross acres (27 million net acres). In 2005, EnCana relinquished approximately 54 million gross acres of the original concession under Permit H. EnCana acquired seismic data and completed the drilling of one exploration well in 2005. In 2006, the Corporation plans to acquire seismic data and anticipates drilling approximately five to eight gross exploration and/or appraisal wells.

Brazil

In November 2005, EnCana reached an agreement to sell its 50 percent working interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. A subsidiary of EnCana made the discovery in 2004 and two successful appraisal wells were drilled in 2005. The sale is subject to regulatory approvals and other closing conditions and is expected to close in the first quarter of 2006. The Chinook field is located in the Campos Basin (Block BM-C-7), and is approximately 75 kilometres offshore Brazil. At December 31, 2005, EnCana's working interest in the block comprised approximately 133,000 gross acres (89,000 net acres). After the transfer of a 16.7 percent earned-in share to its partner, expected to occur in early 2006, EnCana expects to have a 50 percent operated working interest in the block at the time of the sale.

In addition to Block BM-C-7, EnCana has non-operated interests in eight deep and ultra-deep water exploration blocks offshore Brazil, seven of which are operated by Petrobras, the Brazilian national oil company. EnCana's landholdings on these blocks total approximately 1.3 million gross acres (0.4 million net acres) with an average working interest of 35 percent. Seismic work was performed on several of these blocks in 2005. EnCana and its partners are planning to drill one gross exploration well in 2006 in the Campos Basin.

In October 2005, EnCana was awarded a 20 percent working interest in two deep water exploration blocks offshore Brazil in the Potiguar Basin in Agência Nacional do Petróleo ("ANP") Bid Round 7. These blocks encompass approximately 379,000 gross acres (76,000 net acres) and are also operated by Petrobras. The concession agreement for these blocks was signed in January 2006.

The Corporation is also working with Petrobras on the development of heavy oil technology that may be used to develop Brazil's significant heavy oil reserves.

Middle East

EnCana has a 100 percent working interest in Block 2, which encompasses most of the onshore lands in the State of Qatar and covers approximately 2.2 million acres. In 2005, EnCana reached an agreement to farmout 50 percent of its working interest in the block. At December 31, 2005, the agreement was awaiting approval by Qatar Petroleum. One gross well is planned for the block in 2006.

In 2005, EnCana farmed-out a 50 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman. The blocks cover approximately 9.6 million acres. EnCana retained a 50 percent operated interest in the blocks (approximately 4.8 million net acres) and drilled two unsuccessful wells in 2005. The Corporation plans to drill two additional gross wells in 2006.

In February 2005, EnCana exited the Kingdom of Bahrain with the expiration of the Exploration and Production Sharing Agreement, under which it held a 50 percent working interest in Block 5. In June 2005, EnCana exited the Republic of Yemen with its withdrawal from the Production Sharing Agreement, under which it held a 36.75 percent working interest in Block 47.

Greenland

EnCana has an 87.5 percent working interest in two exploration blocks in Greenland, comprising approximately 1.7 million gross acres (1.5 million net acres). In the 2004 Offshore West Greenland Bid Round, EnCana acquired one exploration license (Lady Franklin), which was signed in January 2005. EnCana also has an interest in the Atammik block, offshore west Greenland. In 2005, EnCana conducted seismic surveys on these blocks. In 2006, EnCana plans to pursue the farmout of a portion of its working interest in both blocks.

France

In October 2004, EnCana filed an application for the Foix exploration permit, which encompasses approximately 860,000 acres in the onshore Aquitaine Basin in southwest France. In February 2006, a subsidiary of EnCana was granted a 100 percent interest in this exploration permit. The Corporation has plans for a multi-well exploration drilling program in 2006 and 2007 to identify the potential for a natural gas resource play development.

Ecuador

In October 2004, EnCana announced its intention to dispose of its Ecuador assets. In September 2005, the Corporation reached an agreement to sell all of its interests in Ecuador for approximately $1.42 billion. The effective date of the sale is July 1, 2005. The sale is subject to approval by the Government of Ecuador, regulatory approvals and other closing conditions. EnCana expects the sale to close in the first quarter of 2006. As a result, Ecuador is reported as discontinued operations for financial reporting purposes.

A subsidiary of EnCana owns a concession in the Oriente Basin, known as the Tarapoa Block. The subsidiary 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 relation to 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, 2005, EnCana held an average 64 percent working and economic interest in approximately 1.4 million gross acres (approximately 892,000 net acres, of which approximately 785,000 net acres are undeveloped) in Ecuador. At December 31, 2005, 246 gross crude oil wells (170 net wells) were producing. EnCana's contractual entitlement to net crude oil production in 2005 was 72,916 barrels per day (76,872 barrels per day in 2004). In 2005, EnCana's Ecuador operations had core capital expenditures of approximately $179 million and approximately 19 net wells were drilled. The core capital expenditures were focused mainly on the non-operated Block 15 and the south blocks (including Blocks 14, 17 and Shiripuno).

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 2005, shipments on OCP totalled approximately 158,024 barrels per day (170,599 barrels per day in 2004). 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 began shipping on OCP in September 2003, and has a 15-year shipping commitment of approximately 108,000 barrels per day. EnCana's shipments on OCP in 2005 averaged approximately 67,527 barrels per day (72,636 barrels per day in 2004).

MIDSTREAM & MARKETING

EnCana's marketing groups are focused on enhancing the netback price 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. In addition, EnCana's power assets are managed to optimize the Corporation's electricity costs, particularly in the Province of Alberta. The Midstream & Marketing division also holds the remainder of EnCana's midstream assets, which the Corporation plans to divest in 2006.

Natural Gas Marketing

In 2005, approximately 90 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 10 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 help mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to produced natural gas. For 2006, after taking into account its risk management contracts, EnCana's gas sales price portfolio exposure consists of approximately 22 percent at fixed prices, approximately 71 percent with insured floor prices and approximately 7 percent at other prices. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (131,638 barrels per day in 2005 and 140,911 barrels per day in 2004). 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 the Enbridge system, for sales to U.S. refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2005, EnCana acted as exclusive agent for Canadian Oil Sands Limited ("COS") and marketed COS' Syncrude volumes of 81,019 barrels per day (85,157 barrels per day in 2004). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government's Department of Energy (48,425 barrels per day in 2005 and 53,026 barrels per day in 2004). 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 75,488 barrels per day was marketed in 2005 (77,845 barrels per day in 2004). 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 help 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 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

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 & Marketing 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 250 megawatts and its generation capacity is approximately 239 megawatts.

Midstream

In 2005, the majority of EnCana's midstream assets were deemed to be non-core to the Corporation. In December 2005, EnCana and certain affiliates completed the sale of the Corporation's NGLs processing business for approximately $625 million. EnCana is currently in the process of divesting the majority of its remaining midstream assets, including its natural gas storage business and the Entrega Pipeline. As a result of these planned dispositions, Midstream is reported as discontinued operations for financial reporting purposes.

Natural Gas Storage

In June 2005, EnCana announced plans to sell its natural gas storage business. The sale is expected to close in the second quarter of 2006. EnCana intends to retain ownership of its Hythe storage facility due to its integration with Upstream operations.

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. The AECO HUB in Alberta is Canada's largest natural gas storage and trading hub. EnCana also leases natural gas storage capacity from another storage operator located in the U.S. mid-continent region. At December 31, 2005, EnCana had owned and operated storage capacity of approximately 174 billion cubic feet, including the 10 billion cubic feet Hythe facility, as well as leased storage capacity of approximately 8.5 billion cubic feet. In July 2005, a subsidiary of EnCana received FERC approval to proceed with the development of its previously announced new Starks natural gas storage facility in southwest Louisiana.

EnCana provides a portion of its storage capacity under multi-year firm contracts to industry participants on a fee-for-service basis as well as offering short-term firm or interruptible storage services, 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).

The following table is a summary of EnCana's natural gas storage assets as at December 31, 2005.

Gas Storage Facility:	Location	Storage Capacity	Withdrawal Capability	Injection Capability
		(billions of cubic feet)	(billions of cubic feet per day)	
AECO HUB:				
Suffield	Southeast Alberta	85	1.80	1.60
Hythe	Northwest Alberta	10	0.20	0.15
Countess	Southeast Alberta	40	1.25	0.95
Wild Goose	Northern California	24	0.48	0.45
Salt Plains	Northern Oklahoma	15	0.20	0.15
Total Owned and Operated Capacity		174	3.93	3.30
Total Leased Capacity[1]	U.S. mid-continent	8.5	0.09	0.19

Note:

(1) Contract terms range from 16 months to 11 years.

Pipelines

In August 2005, Entrega received FERC approval to proceed with its previously announced natural gas pipeline project. 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. Construction of the first segment of the pipeline (from Meeker Hub, Colorado to Wamsutter, Wyoming) was completed in December 2005, and is expected to be in service in February, 2006. The first segment has a capacity of approximately 750 million cubic feet per day.

In November 2005, Entrega entered into a purchase and sale agreement with KMP. Under the terms of the agreement, it is expected that KMP will purchase Entrega and construct the second segment of the pipeline (from Wamsutter to the Cheyenne Hub), as well as a potential extension. It is anticipated that the Entrega Pipeline will become part of KMP's proposed Rockies Express Pipeline. The sale is expected to close in the first quarter of 2006.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's natural gas, crude oil and NGLs reserves as of December 31, 2005. EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. EnCana's U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton. EnCana's Ecuadorian reserves were evaluated by GLJ Petroleum Consultants Ltd. Since EnCana's inception in 2002, all of the Corporation's reserves have been independently evaluated on an annual basis.

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.

Ecuador has been reported as discontinued operations for financial reporting purposes since December 31, 2004.

Reserve Quantities Information

EnCana's natural gas reserves increased approximately 13 percent in 2005 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 2,541 billion cubic feet. Included in the revisions and improved recovery category for changes in natural gas reserves were positive revisions in Canada and downward revisions in the U.S., resulting in total revisions of negative 58 billion cubic feet, or less than one percent of proved natural gas reserves at the beginning of 2005. CBM accounted for the majority of the 202 billion cubic feet of positive revisions in Canada. Downward revisions of 260 billion cubic feet in the U.S. occurred mainly in the southern Rockies where performance led to lower per well reserves. During 2004, the Corporation's natural gas reserves increased from exploration and development drilling and acquisitions.

EnCana's crude oil and NGLs reserves increased significantly in 2005, largely as a result of a 657 million barrel increase in bitumen reserves primarily at Foster Creek. Included in this increase is the reinstatement, due to prices at year-end 2005, of 363 million barrels that appeared as a downward revision in 2004 due to anomalously lower bitumen prices at year-end 2004. The Corporation's crude oil and NGLs reserves decreased in 2004 primarily as a result of the divestiture of non-core properties and the negative revision in Canadian bitumen reserves.

EnCana's reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including SFAS 69. The end of year numbers for 2005 and 2004 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2003 represent estimates derived from the reports of the independent qualified reserves evaluators who evaluated EnCana's reserves as of December 31, 2003.

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
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	0.2	(11.5)			19.8
Extensions and discoveries	1,422	1,009			2,431	93.6	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)[3]					(362.7)
End of year	5,824	4,636			10,460	266.9	91.0	143.3			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
2005											
Beginning of year	5,824	4,636			10,460	266.9	91.0	143.3			501.2
Revisions and improved recovery	202	(260)			(58)	222.1	(3.2)	8.1			227.0
Extensions and discoveries	1,289	1,252			2,541	148.1	8.9	10.2			167.2
Purchase of reserves in place	7	76			83		0.4				0.4
Sale of reserves in place	(30)	(37)			(67)	(15.1)	(39.0)				(54.1)
Production	(775)	(400)			(1,175)	(52.2)	(5.0)	(26.6)			(83.8)

	Natural Gas (billions of cubic feet)			Crude Oil and Natural Gas Liquids (millions of barrels)			
End of year before reinstatement of bitumen	6,517	5,267	11,784	569.8	53.1	135.0	757.9
Reinstatement of bitumen				362.7(4)			362.7
End of year	6,517	5,267	11,784	932.5(5)	53.1	135.0(6)	1,120.6
Developed	4,513	2,718	7,231	318.7	32.2	104.0	454.9
Undeveloped	2,004	2,549	4,553	613.8	20.9	31.0	665.7
Total	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6

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) Removal of the Corporation's Foster Creek proved bitumen reserves as a result of low bitumen prices on December 31, 2004. This included approximately 5.4 million barrels that were included under revisions and improved recovery and approximately 70.4 million barrels that were included under extensions and discoveries in 2004.

(4) Reinstatement, as a result of year-end 2005 prices, of the Corporation's Foster Creek proved bitumen reserves that were deducted as a revision due to bitumen price at year-end 2004.

(5) Proved crude oil and NGLs reserves at December 31, 2005 include 657.4 million barrels of bitumen, the vast majority of which are located at Foster Creek. Changes to bitumen reserves during 2005 included revisions of 174.6 million barrels and extensions and discoveries of 134.0 million barrels.

(6) The Corporation expects to complete the disposition of its Ecuadorian operations in 2006. Accordingly, Ecuador is reported as discontinued operations 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 SFAS 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 price 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		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
				($ millions)					
Future cash inflows	71,786	37,791	35,126	40,504	27,063	17,472	5,350	3,317	3,533
Less future:									
Production costs	16,765	7,760	9,630	3,262	2,462	1,456	2,093	1,136	738
Development costs	6,164	3,157	3,024	4,174	3,213	1,336	429	198	211
Asset retirement obligation payments	2,269	1,749	1,364	264	193	97	24	22	38
Income taxes	13,170	6,279	5,874	11,041	7,021	4,960	662	342	536
Future net cash flows	33,418	18,846	15,234	21,763	14,174	9,623	2,142	1,619	2,010
Less 10% annual discount for estimated timing of cash flows	13,281	6,668	5,219	10,291	6,686	4,735	574	417	643
Discounted future net cash flows	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367

	United Kingdom			Total		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**
				($ millions)		
Future cash inflows			3,483	117,640	68,171	59,614
Less future:						
Production costs			961	22,120	11,358	12,785
Development costs			941	10,767	6,568	5,512
Asset retirement obligation payments			67	2,557	1,964	1,566
Income taxes			456	24,873	13,642	11,826
Future net cash flows			1,058	57,323	34,639	27,925
Less 10% annual discount for estimated timing of cash flows			493	24,146	13,771	11,090

	United Kingdom	Total		
Discounted future net cash flows	565	33,177	20,868	16,835

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

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
				($ millions)					
Balance, beginning of year	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258
Changes resulting from:									
Sales of oil and gas produced during the period	(5,720)	(3,965)	(3,429)	(2,436)	(1,474)	(889)	(604)	(264)	(258)
Discoveries and extensions, net of related costs	4,278	3,562	1,272	3,582	2,436	1,381	159	236	126
Purchases of proved reserves in place	26	531	26	237	2,786	340			93
Sales of proved reserves in place	(279)	(1,579)	(95)	(486)	(271)	(108)			(54)
Net change in prices and production costs	11,624	2,264	242	4,716	143	2,751	967	(294)	(47)
Revisions to quantity estimates	1,071	546	416	(700)	(542)	4	88	(125)	4
Accretion of discount	1,629	1,349	1,636	1,103	725	304	147	176	182
Previously estimated development costs incurred net of change in future development costs	(888)	57	340	162	22	534	(148)	15	89
Other	63	32	470	(64)	(49)	157	8	(29)	(27)
Net change in income taxes	(3,845)	(634)	304	(2,130)	(1,176)	(1,737)	(251)	120	1
Balance, end of year	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367

	United Kingdom			Total		
	2005	2004	2003	2005	2004	2003
				($ millions)		
Balance, beginning of year		565	411	20,868	16,835	12,653
Changes resulting from:						
Sales of oil and gas produced during the period		(78)	(83)	(8,760)	(5,781)	(4,659)
Discoveries and extensions, net of related costs				8,019	6,234	2,779
Purchases of proved reserves in place		77	57	263	3,394	516
Sales of proved reserves in place		(899)		(765)	(2,749)	(257)
Net change in prices and production costs			(119)	17,307	2,113	2,827
Revisions to quantity estimates			157	459	(121)	581
Accretion of discount		82	91	2,879	2,332	2,213
Previously estimated development costs incurred net of change in future development costs			108	(874)	94	1,071
Other			(38)	7	(46)	562
Net change in income taxes		253	(19)	(6,226)	(1,437)	(1,451)
Balance, end of year			565	33,177	20,868	16,835

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador(1)		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs	6,701	4,787	4,189	3,052	1,861	1,091	873	451	367
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	981	822	760	616	387	202	269	187	109
Depreciation, depletion and amortization	1,961	1,752	1,511	712	487	297	234	263	159
Operating income (loss)	3,759	2,213	1,918	1,724	987	592	370	1	99
Income taxes	1,274	841	218	638	375	219	134	5	17
Results of operations	2,485	1,372	1,700	1,086	612	373	236	(4)	82

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs		117	102				10,626	7,216	5,749
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations		39	19	6	4	20	1,872	1,439	1,110
Depreciation, depletion and amortization		118	74	8	25	83	2,915	2,645	2,124
Operating income (loss)		(40)	9	(14)	(29)	(103)	5,839	3,132	2,515
Income taxes		(15)	17			(4)	2,046	1,206	467
Results of operations		(25)	(8)	(14)	(29)	(99)	3,793	1,926	2,048

Note:

(1) Ecuador is treated as discontinued operations for financial reporting purposes. The results of operations for 2005 includes a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments.

Capitalized Costs

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Proved oil and gas properties	27,074	22,455	18,549	7,753	7,552	3,485	1,926	1,784	1,372
Unproved oil and gas properties	1,998	1,855	1,981	870	728	501	18	45	70
Total capital cost	29,072	24,310	20,530	8,623	8,280	3,986	1,944	1,829	1,442

	Canada			United States			Ecuador		
Accumulated DD&A	12,131	9,770	7,498	1,750	1,046	516	778	534	188
Net capitalized costs	16,941	14,540	13,032	6,873	7,234	3,470	1,166	1,295	1,254

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Proved oil and gas properties			675				36,753	31,791	24,081
Unproved oil and gas properties			77	470	425	317	3,356	3,053	2,946
Total capital cost			752	470	425	317	40,109	34,844	27,027
Accumulated DD&A			230	222	247	206	14,881	11,597	8,638
Net capitalized costs			522	248	178	111	25,228	23,247	18,389

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Costs Incurred

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	($ millions)								
Acquisitions									
Unproved reserves		42	47	271	954	21			80
Proved reserves	30	204	207	141	2,051	115			59
Total acquisitions	30	246	254	412	3,005	136			139
Exploration costs	817	555	846	264	164	187	15	28	20
Development costs	3,333	2,669	2,131	1,724	1,103	651	164	213	111
Total costs incurred	4,180	3,470	3,231	2,400	4,272	974	179	241	270

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	($ millions)								
Acquisitions									
Unproved reserves			16				271	996	164
Proved reserves		130	95				171	2,385	476
Total acquisitions		130	111				442	3,381	640
Exploration costs		22	30	70	79	78	1,166	848	1,161
Development costs		364	96				5,221	4,349	2,989
Total costs incurred		516	237	70	79	78	6,829	8,578	4,790

Sales Volumes, Royalty Rates and Per-Unit Results

Sales Volumes

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

	Sales Volumes 2005				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal/(injection)	7				27
Canada Sales	2,132	2,172	2,123	2,151	2,079
United States	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	47,328	45,792	43,313	50,020	50,280
Heavy Oil	83,090	88,386	81,089	82,274	80,546
Natural Gas Liquids[(1)]					
Canada	11,907	12,287	11,924	11,719	11,692
United States	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations ***(MMcfe/d)***	4,163	4,282	4,125	4,155	4,089
Discontinued Operations:					
Ecuador					
Production[(2)]	72,916	70,480	71,896	73,662	75,695
(Under)/over lifting	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales *(bbls/d)*	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations ***(MMcfe/d)***	426	419	412	439	435
Total ***(MMcfe/d)***	4,589	4,701	4,537	4,594	4,524

Notes:

(1)

Natural gas liquids include condensate volumes.

(2) Includes approximately 28,700 bbls/day related to Block 15. Information regarding the status of the participation contract for Block 15 can be found in Note 4 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

	Sales Volumes 2004				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada					
Production	2,105	2,106	2,138	2,177	2,000
Inventory (injection)/withdrawal	(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[2]					
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[3]	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
Discontinued Operations:					
Ecuador					
Production[4]	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 *(MMcfe/d)*	4,560	4,595	4,684	4,655	4,302

Notes:

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

(2) Natural gas liquids include condensate volumes.

(3)

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

(4) Includes approximately 31,000 barrels per day related to Block 15.

	Sales Volumes 2003				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
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(1)					
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
Discontinued Operations:					
Ecuador					
Production	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline(2)	(3,213)		(4,919)	(2,039)	(5,941)
(Under)/over 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
Total Discontinued Operations *(MMcfe/d)*	399	574	301	333	385
Total *(MMcfe/d)*	3,947	4,283	3,856	3,748	3,899

Notes:

(1)

Natural gas liquids include condensate volumes.

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

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.

	2005					2004					2003				
	Year	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	11.7	11.9	11.8	11.0	11.9	12.5	12.0	12.2	12.7	13.3	12.9	12.2	12.9	14.2	12.4
United States	18.6	18.6	19.9	17.9	18.1	19.6	19.8	18.3	21.1	19.3	20.0	19.5	20.2	20.1	20.5
Crude Oil															
Canada and United States	8.8	8.8	8.7	9.2	8.7	9.0	8.7	8.8	11.6	9.4	10.3	9.7	9.0	10.7	11.8
Natural Gas Liquids															
Canada	14.9	14.4	15.8	15.6	13.8	15.7	16.5	18.5	13.1	14.8	17.5	14.7	16.6	18.0	20.2
United States	18.2	19.4	20.1	12.7	20.0	18.7	21.4	13.6	20.7	19.2	17.6	17.5	17.0	17.3	18.5
Total North America	13.3	13.5	13.8	12.6	13.3	13.7	13.8	13.2	14.1	13.7	13.8	13.2	13.4	14.5	13.9
Discontinued Operations:															
Crude Oil Ecuador	27.2	29.4	26.3	26.3	26.9	27.1	27.8	26.5	26.5	27.4	25.6	25.4	25.7	24.9	26.9

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 2005				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	0.10	0.10	0.10	0.10	0.09
Transportation and selling	0.36	0.36	0.36	0.36	0.37
Operating	0.67	0.72	0.68	0.62	0.65
Netback	6.14	8.82	6.04	5.00	4.59
Produced Gas United States ($/Mcf)					
Price	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	0.81	1.19	0.75	0.65	0.62
Transportation and selling	0.46	0.45	0.49	0.42	0.46
Operating	0.53	0.60	0.55	0.50	0.45
Netback	6.02	8.60	5.72	5.03	4.51

Per-Unit Results 2005					
Produced Gas Total North America ($/Mcf)					
Price	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	0.34	0.48	0.32	0.28	0.27
Transportation and selling	0.40	0.39	0.41	0.38	0.40
Operating	0.62	0.68	0.64	0.58	0.58
Netback	6.10	8.74	5.92	5.01	4.56

	Per-Unit Results 2005				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes					
Transportation and selling	0.42	0.46	0.48	0.39	0.35
Netback	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids United States ($/bbl)					
Price	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	4.86	5.42	5.46	4.37	4.20
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids Total North America ($/bbl)					
Price	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	2.60	2.77	2.96	2.31	2.34
Transportation and selling	0.20	0.23	0.23	0.19	0.16
Netback	43.64	48.87	47.74	39.82	38.03
Crude Oil Light and Medium North America ($/bbl)					
Price	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	1.54	1.83	1.29	1.71	1.32
Transportation and selling	1.20	1.14	1.29	1.20	1.19
Operating	6.34	6.41	6.24	6.34	6.38
Netback	36.01	36.89	46.59	32.19	29.68
Crude Oil Heavy North America ($/bbl)					
Price	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	0.04	0.05	0.04	0.02	0.03
Transportation and selling	1.20	1.11	1.08	1.13	1.52
Operating	6.50	6.96	6.57	6.57	5.83
Netback	20.18	20.15	32.00	15.05	13.38
Crude Oil Total North America ($/bbl)					
Price	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	0.58	0.66	0.48	0.66	0.53
Transportation and selling	1.20	1.12	1.15	1.15	1.39
Operating	6.44	6.77	6.45	6.48	6.04
Netback	25.93	25.86	37.08	21.54	19.64
Total Liquids Canada ($/bbl)					
Price	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	0.53	0.60	0.43	0.61	0.48
Transportation and selling	1.14	1.07	1.09	1.09	1.31
Operating	5.89	6.19	5.83	5.96	5.55
Netback	27.41	27.79	38.00	22.92	21.26

	Per-Unit Results	2005

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	Per-Unit Results 2005				
	Year	Q4	Q3	Q2	Q1
Total Liquids Total North America ($/bbl)					
Price	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	0.91	0.99	0.91	0.92	0.83
Transportation and selling	1.04	0.98	0.99	1.00	1.18
Operating	5.38	5.70	5.33	5.46	5.03
Netback	28.84	29.49	38.93	24.42	22.73
Total North America ($/Mcfe)					
Price	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	0.30	0.41	0.29	0.25	0.24
Transportation and selling	0.35	0.34	0.35	0.33	0.36
Operating[(1)]	0.68	0.74	0.69	0.66	0.64
Netback	5.80	7.88	6.05	4.79	4.38
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	5.04	4.63	7.66	4.53	3.42
Transportation and selling	2.25	1.86	2.45	2.48	2.21
Operating	5.32	5.82	6.05	5.18	4.26
Netback	26.75	25.51	31.60	24.18	25.91

Note:

(1) Year-to-date operating costs include costs related to long-term incentives of $0.03/Mcfe.

	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

	Per-Unit Results 2004				
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

	Per-Unit Results 2004				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes					
Transportation and selling	0.41	0.47	0.45	0.35	0.35
Netback	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids United States ($/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

Per-Unit Results 2004					
Total Liquids Total 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 ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating[1]	0.55	0.59	0.53	0.52	0.58
Netback	4.23	4.72	4.18	4.11	3.87
Discontinued Operations:					
Crude Oil Ecuador ($/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

Note:

(1) Year-to-date operating costs include costs related to long-term incentives of $0.01/Mcfe.

	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

	Per-Unit Results 2003				
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

	Per-Unit Results 2003				
	Year	Q4	Q3	Q2	Q1
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 ($/bbl)					
Price	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	1.24	1.54	0.58	1.37	1.56
Operating	5.67	4.95	5.93	6.18	5.70
Netback	12.73	11.85	11.91	12.18	15.38
Crude Oil Total North America ($/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

	Per-Unit Results 2003				
Total Liquids Total 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

	Per-Unit Results 2003				
	Year	Q4	Q3	Q2	Q1
Total North America ($/Mcfe)					
Price	4.57	4.24	4.31	4.58	5.17
Production and mineral taxes	0.13	0.15	0.10	0.14	0.12
Transportation and selling	0.33	0.39	0.31	0.31	0.31
Operating	0.54	0.52	0.58	0.55	0.53
Netback	3.57	3.18	3.32	3.58	4.21
<u>Discontinued Operations:</u>					
Crude Oil Ecuador ($/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

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

	2005				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.32)	(0.88)	(0.39)	(0.14)	0.18
Liquids ($/bbl)	(5.18)	(5.00)	(5.70)	(4.88)	(5.18)
Total ($/Mcfe)	(0.44)	(0.87)	(0.52)	(0.30)	(0.06)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(4.92)	(3.57)	(7.81)	(4.90)	(3.48)

	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)					

Note:

(1) Excludes hedges unwound as a result of the United Kingdom 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:											
2005:											
Canada	605	540	8	8	7	7	620	555	99	719	555
United States	7	6			9	7	16	13	1	17	13
Other			3	1	3	2	6	3		6	3
Total	612	546	11	9	19	16	642	571	100	742	571
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
Discontinued Operations:											
Ecuador 2005			2	1	3	2	5	3		5	3
Ecuador 2004			6	3			6	3		6	3
Ecuador 2003			3	2			3	2		3	2
United Kingdom 2004			1		4	2	5	2		5	2
United Kingdom 2003			2	1	5	3	7	4		7	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:											
2005:											
Canada	3,503	3,229	277	243	12	11	3,792	3,483	932	4,724	3,483
United States	699	604					699	604	9	708	604
Total	4,202	3,833	277	243	12	11	4,491	4,087	941	5,432	4,087
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
Discontinued Operations:											
Ecuador 2005			28	15	3	1	31	16		31	16
Ecuador 2004			43	25	1	1	44	26		44	26
Ecuador 2003			53	39	6	6	59	45		59	45
United Kingdom 2004			3	1			3	1		3	1
United Kingdom 2003			3				3			3	

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, 2005, EnCana was in the process of drilling 50 gross wells (45 net wells) in Canada, 95 gross wells (89 net wells) in the United States, zero wells in Ecuador and one well in another country.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2005:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	32,943	31,054	4,056	3,671	36,999	34,725
British Columbia	1,664	1,513	17	12	1,681	1,525
Saskatchewan	456	442	1,200	520	1,656	962
Manitoba			1	1	1	1
Total Canada	35,063	33,009	5,274	4,204	40,337	37,213
Colorado	4,493	3,535	6	3	4,499	3,538
Texas	1,931	1,283	40	15	1,971	1,298
Wyoming	1,372	1,093	1	1	1,373	1,094
Utah	64	60	2	1	66	61
Oklahoma	95	22			95	22
Louisiana	3	2			3	2
Total United States	7,958	5,995	49	20	8,007	6,015
Total	43,021	39,004	5,323	4,224	48,344	43,228
Discontinued Operations:						
Ecuador			286	200	286	200

Notes:

(1) EnCana has varying royalty interests in 13,847 natural gas wells and 8,779 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 31,405 gross natural gas wells (28,524 net wells) and 696 gross crude oil wells (548 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2005:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	Fee	4,424	4,424	2,706	2,706	7,130	7,130
	Crown	3,842	3,020	5,798	4,818	9,640	7,838
	Freehold	223	130	262	220	485	350
		8,489	7,574	8,766	7,744	17,255	15,318
British Columbia	Crown	875	749	4,495	3,961	5,370	4,710
	Freehold			7	7	7	7
		875	749	4,502	3,968	5,377	4,717
Saskatchewan	Fee	58	58	457	457	515	515
	Crown	158	146	571	557	729	703
	Freehold	14	10	62	60	76	70
		230	214	1,090	1,074	1,320	1,288
Manitoba	Fee	3	3	263	263	266	266
	Freehold			7	7	7	7
		3	3	270	270	273	273
Newfoundland & Labrador	Crown			2,549	1,707	2,549	1,707
Nova Scotia	Crown			1,353	683	1,353	683
Northwest Territories	Crown			178	62	178	62
Nunavut	Crown			817	26	817	26
Beaufort	Crown			126	4	126	4
Total Canada		9,597	8,540	19,651	15,538	29,248	24,078

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	Federal/State Lands	188	174	841	774	1,029	948
	Freehold	101	95	174	160	275	255
	Fee	3	3	47	47	50	50
		292	272	1,062	981	1,354	1,253
Washington	Federal/State Lands			668	657	668	657
	Freehold			180	180	180	180
				848	837	848	837
Texas	Federal/State Lands	9	3	446	446	455	449
	Freehold	330	142	1,090	925	1,420	1,067
	Fee			1	1	1	1
		339	145	1,537	1,372	1,876	1,517
Wyoming	Federal/State Lands	142	82	696	501	838	583
	Freehold	25	18	67	40	92	58
		167	100	763	541	930	641
Other	Federal/State Lands	12	9	352	211	364	220
	Freehold	10	5	77	76	87	81
		22	14	429	287	451	301
Total United States		820	531	4,639	4,018	5,459	4,549
Chad				54,103	27,052	54,103	27,052
Oman				9,606	4,803	9,606	4,803
Qatar				2,161	2,161	2,161	2,161
Greenland				1,701	1,488	1,701	1,488
Brazil				1,416	535	1,416	535
Australia				1,053	357	1,053	357
Azerbaijan				346	17	346	17
Total International				70,386	36,413	70,386	36,413
Total		10,417	9,071	94,676	55,969	105,093	65,040
Discontinued Operations:							
Ecuador		169	107	1,230	785	1,399	892

Notes:

(1) This table excludes approximately 4.2 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. Prior to 2004, 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, equity, cash generated from operations, proceeds from asset dispositions or a combination of these sources.

The following table summarizes EnCana's net capital investment for 2004 and 2005.

	2005	2004
	($ millions)	
Upstream		
Canada	4,150	3,015
United States	1,982	1,249
Other Countries	70	79
	6,202	4,343
Midstream & Marketing	197	10
Corporate	78	46
Core Capital from Continuing Operations	6,477	4,399
Upstream		
Acquisitions		
Property		
Canada	30	64
United States	418	300
Corporate		
Petrovera		253
Tom Brown, Inc.[1]		2,335
Dispositions		
Property		
Canada	(447)	(877)
United States	(2,074)	(266)
Corporate		
Petrovera		(540)
Midstream & Marketing		
Property		(1)
Corporate		
Kingston CoGen		(25)
Corporate	(2)	
Net Acquisition and Disposition Activity from Continuing Operations	(2,075)	1,243
Discontinued Operations		
Ecuador	179	240
United Kingdom		(1,656)
Midstream	(484)	(20)
Net Capital Investment	4,097	4,206

Note:

(1)

Net cash consideration excluding debt acquired of $406 million.

EnCana plans to dispose of various non-core assets in 2006, including its interests in Ecuador, the Chinook discovery in Brazil, its gas storage business, the Entrega Pipeline 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. 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 18 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

GENERAL

Competitive Conditions

All aspects of the oil and gas industry are highly competitive and EnCana actively competes with oil and natural gas and other companies, particularly in the following areas: (i) exploration for and development of new sources of oil and natural gas reserves; (ii) reserve and property acquisitions; (iii) transportation and marketing of oil, natural gas and NGLs; (iv) access to services and equipment to carry out exploration, development or operating activities; and (v) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries focused on providing alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of oil and natural gas, both of which could have a negative impact on EnCana's financial results.

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 ("EH&S") 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 2005, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2006. 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 $4.9 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) a comprehensive approach to training and communicating policies and practices; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide; (v) corporate responsibility performance metrics to track the Corporation's progress; (vi) contribution of a minimum of one percent of EnCana's pre-tax domestic profits to charitable and non-profit organizations in the communities in which EnCana operates; (vii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of EnCana policies or practices and other regulations; (viii) an Integrity Hotline that provides an additional avenue for EnCana's stakeholders to raise their concerns; (ix) an internal corporate EH&S audit program that evaluates EnCana's compliance with the expectations and requirements of the EH&S management system; and (x) 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, 2005, EnCana employed 4,547 full time equivalent ("FTE") employees as set forth in the following table:

	FTE Employees
Upstream	3,618
Midstream & Marketing	273
Corporate	656
Total	4,547

The Corporation also engages a number of contractors and service providers.

Foreign Operations

As at December 31, 2005, approximately 96 percent of EnCana's reserves and 91 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 "Name and Incorporation" 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 and facilitate acquisitions and dispositions. 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 help reduce administrative burdens. In October 2005, EnCana completed a restructuring to facilitate the sale of its NGLs business and the planned sale of its gas storage business. In addition, in December 2005 the Corporation initiated a restructuring of various Canadian subsidiaries in order to eliminate corporate entities that had become unnecessary. EnCana expects to complete this restructuring in February 2006.

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[12]	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	Group Executive Vice President & Chief Operating Officer of the General Partner of Enterprise Products L.P. (Enterprise Products GP, LLC) *(Midstream energy services)*
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)*
RANDALL K. ERESMAN Calgary, Alberta, Canada	2006	President & Chief Executive Officer EnCana Corporation
MICHAEL A. GRANDIN[3,4,6,8] Calgary, Alberta, Canada	1998	Chairman & Chief Executive Officer Fording Canadian Coal Trust *(Metallurgical coal)*

Name and Municipality of Residence	Director Since[12]	Principal Occupation
BARRY W. HARRISON[1,4,9] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
DALE A. LUCAS[1,5] Calgary, Alberta, Canada	1997	Corporate Director
KEN F. MCCREADY[2,5,10] Calgary, Alberta, Canada	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
GWYN MORGAN Calgary, Alberta, Canada	1993	Executive Vice-Chairman EnCana Corporation
VALERIE A. A. NIELSEN[2,6] Calgary, Alberta, Canada	1990	Corporate Director
DAVID P. O'BRIEN[4,7,11] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT[1] West Vancouver, British Columbia, Canada	2003	President & Chief Executive Officer British Columbia Transmission Corporation *(Electrical transmission)*
DENNIS A. SHARP[2,4] Calgary, Alberta, Canada & Montreal, Quebec, Canada	1998	Executive Chairman UTS Energy Corporation *(Oilsands 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. 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.

(9)

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.

(10)

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.

(11)

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.

(12)

Denotes the year each individual became a director of EnCana or one of its predecessor companies (AEC or PanCanadian).

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

At the date of this annual information form, there are 15 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 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
DAVID P. O'BRIEN Calgary, Alberta, Canada	Chairman
GWYN MORGAN(1) Calgary, Alberta, Canada	Executive Vice-Chairman
RANDALL K. ERESMAN(1) Calgary, Alberta, Canada	President & Chief Executive Officer
ROGER J. BIEMANS(2) Denver, Colorado, United States	Executive Vice-President
BRIAN C. FERGUSON(3) Calgary, Alberta, Canada	Executive Vice-President, Corporate Development
MICHAEL M. GRAHAM Calgary, Alberta, Canada	Executive Vice-President
R. WILLIAM OLIVER Calgary, Alberta, Canada	Executive Vice-President
GERARD J. PROTTI Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations
HAYWARD J. WALLS(4) Calgary, Alberta, Canada	Executive Vice-President, Corporate Services & Chief Information Officer
JOHN D. WATSON(3) Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
JEFF E. WOJAHN(2) Calgary, Alberta, Canada	Executive Vice-President

Notes:

(1) Gwyn Morgan stepped down as President & Chief Executive Officer effective December 31, 2005. He has agreed to remain an officer of the Corporation in the role of Executive Vice-Chairman for the year 2006. Effective January 1, 2006, Randy Eresman became President & Chief Executive Officer and a Director of the Corporation.

(2) Effective March 1, 2006, Roger Biemans (currently Executive Vice-President and President, USA Region) and Jeff Wojahn (currently Executive Vice-President and President, Canadian Plains Region) will switch positions.

(3) Effective March 1, 2006, Brian Ferguson will succeed John Watson as Executive Vice-President & Chief Financial Officer. Also effective March 1, 2006, Don Swystun (currently President, Ecuador Region) will be appointed Executive Vice-President, Corporate Development.

(4) Successor of Drude Rimell who stepped down as Executive Vice-President, Corporate Services effective December 31, 2005.

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. Cunningham was appointed Group Executive Vice President & Chief Operating Officer of the General Partner of Enterprise Products L.P. (Enterprise Products GP, LLC) effective December 1, 2005, and a director on February 14, 2006. He was appointed as a director and Chairman of the Board of Texas Eastern Products Pipeline Company, LLC effective March 22, 2005 and resigned from the position effective November 23, 2005.

Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006. He 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 Vice President, Corporate Services and Chief Financial Officer of British Columbia Transmission Corporation (BCTC) from June 2003 to April 2005 when she was appointed President and Chief Executive Officer of BCTC. She was President of Union Gas Limited from April 2002 to May 2003, President and Chief Executive Officer from April 2001 to April 2002 and Senior Vice President Sales & Marketing from June 2000 to April 2001.

Mr. Sharp was Chairman and Chief Executive Officer of UTS Energy Corporation from July 1998 to October 2004.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 14, 2006, directly or indirectly, or exercised control or direction over an aggregate of 2,428,657 Common Shares representing 0.29 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 3,160,500 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 five members, all of whom are independent and financially literate in accordance with the definitions in Multilateral Instrument 52-110 *Audit Committees.* 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 a 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), a director of Synenco Energy Inc. (oilsands mining), and a Trustee of Enbridge Commercial Trust, a subsidiary entity of Enbridge Income Fund.

Barry W. Harrison (Audit Committee Chair)

Mr. Harrison holds a Bachelor of Business Administration and Banking (Colorado College) and a Bachelor of Laws (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 Company and its U.S. subsidiary, the Wawanesa General Insurance Company. 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 consulted 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 also a Fellow of The Society of Management Accountants (FCMA). She was Vice President, Corporate Services and Chief Financial Officer of British Columbia Transmission Corporation (electrical transmission) from June 2003 to April 2005, when she was appointed President and Chief Executive Officer. 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: Kinder Morgan, Inc. (North American midstream energy company), OPTI Canada Inc. (oilsands development and upgrading company) and NOVA Chemicals Corporation (commodity chemical company). He was Chairman of the Audit Committee of Inco Limited from April 2002 until August 2005 when he retired from the Board. 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 2005 and 2004:

($ thousands)	2005	2004
Audit Fees[(1)]	3,726	3,177
Audit-Related Fees[(2)]	894	166
Tax Fees[(3)]	1,021	1,097
All Other Fees[(4)]	26	24
Total	5,667	4,464

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 2005 and 2004, 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 2005 and 2004, 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 2005 and 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.

EnCana did not rely on the *de minimus* exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X in 2004 or 2005.

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, 2005 there were approximately 859 million Common Shares outstanding and no Preferred Shares outstanding.

At the annual and special meeting of EnCana's shareholders on April 27, 2005, the Corporation's shareholders approved the subdivision of EnCana's outstanding common shares on a two-for-one basis. Each shareholder received one additional common share for each common share held on the record date for the stock split of May 12, 2005. EnCana's common shares commenced trading on a subdivided basis on May 10, 2005.

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. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

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, 2005.

	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 ten 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. 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 D, representing the range from highest to lowest quality. A-1 (low) is the third highest of eight 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 debt 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 that of 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 securities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such 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 judgment 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 ("TSX") and the New York Stock Exchange ("NYSE") under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2005.

	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)
2005								
January	37.43	32.55	36.68	71.9	30.27	26.45	29.55	38.3
February	42.50	36.48	40.91	63.5	34.62	29.37	33.45	41.5
March	44.28	39.68	42.72	79.8	36.45	32.72	35.21	55.7
April	45.25	39.05	40.27	69.5	37.11	31.31	31.93	54.6
May	44.74	40.00	43.50	52.2	35.50	31.53	34.67	42.2
June	51.27	43.48	48.33	61.1	41.56	34.84	39.59	47.6
July	53.65	47.72	50.47	49.3	43.96	39.26	41.35	43.8
August	58.94	49.56	58.21	75.7	49.77	40.55	49.19	66.1
September	68.70	56.75	67.85	78.0	58.49	47.78	58.31	76.0
October	69.64	51.90	54.00	116.1	59.82	44.50	45.86	149.0
November	57.70	50.04	51.77	73.3	48.80	42.00	44.32	76.4
December	59.95	51.45	52.56	66.9	52.04	43.85	45.16	71.1

Note:

(1) EnCana's common shares began trading on a post-split basis (two-for-one) on May 10, 2005. All data from January 1, 2005 to May 10, 2005 has been adjusted to reflect the share split.

In February 2005, EnCana received approval from the TSX to amend its normal course issuer bid program. Under the amended Bid, EnCana was entitled to purchase up to 92.2 million Common Shares on a post-split basis (10 percent of the public float on October 22, 2004), over a period ending October 28, 2005. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange. During 2005, EnCana purchased approximately 55 million shares under the terms of the Bid for approximately $1.9 billion.

In October 2005, EnCana received approval from the TSX to renew the Bid. Under the renewed Bid, EnCana is entitled to purchase up to 85.6 million Common Shares (10 percent of the public float on October 25, 2005) over a period ending October 30, 2006. As of December 31, 2005, the Corporation had not purchased any shares under the renewed Bid. During January 2006, EnCana purchased approximately 6.8 million shares for approximately $314 million.

EnCana issued one series of debt securities in 2005 that are not listed or quoted on an exchange. On September 21, 2005, the Corporation completed the offering of C$500 million of senior unsecured medium term notes at a price of 99.967 percent. The notes have a coupon rate of 3.60% and mature on September 15, 2008.

During 2005, the Corporation completed the redemption of nine issues of Canadian medium term notes: EnCana's 5.95% notes due October 1, 2007, 5.95% notes due June 2, 2008, 5.80% notes due June 19, 2008, 6.10% notes due June 1, 2009, 7.15% notes due December 17, 2009, 8.50% notes due March 15, 2011, 7.10% notes due October 11, 2011, 7.30% notes due September 2, 2014 and 5.50%/6.20% notes due June 23, 2028. The aggregate principal amount of the notes was C$1.15 billion. The notes were redeemed at a total cost of C$1.3 billion.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2003, cash dividends were paid to common shareholders at a rate of C$0.20 per share annually (C$0.05 per share quarterly). In 2004, EnCana began paying cash dividends to common shareholders in United States dollars at a rate of $0.20 per share annually ($0.05 per share quarterly). In the second quarter of 2005, EnCana increased its dividend by 50 percent to $0.30 per share annually ($0.075 per share quarterly). EnCana's Board of Directors has declared a dividend of $0.075 per share payable on March 31, 2006 to common shareholders of record on March 15, 2006. All of the figures in this section have been adjusted to reflect the May 2005 share split.

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 could 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 production, transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades, making it more susceptible to supply and demand fundamentals. 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, discovering or developing 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 and interest 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 and changes in interest rates.

The terms of the Corporation's various hedging agreements may limit the benefit to the Corporation of commodity price increases or changes in interest rates. 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.

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 drilling and other equipment;
- the ability to access lands;
- 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, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Corporation's existing and planned projects.

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. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. 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.

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. There is currently no clear direction post-2012. The previous Federal Government released a framework outlining its Climate Change action plan on April 13, 2005, and partially addressed the uncertainty associated with ratification and implementation of Kyoto in a July 16, 2005 Canada Gazette notice. The

Gazette notice outlined provisions for the oil and gas sector that limit the cost of compliance for existing facilities to C$15 per tonne and made a commitment that emissions reduction targets would not exceed 12 percent lower than business-as-usual levels of total covered emissions for a given sector. The notice also made a commitment to targets based on the "best available technology economically achievable" for new facilities. With the recent change in the Federal Government, EnCana is unable to predict the impact of the potential regulations on its business; however, it is possible that the Corporation could face increases in operating costs in order to comply with greenhouse gas emissions legislation.

EnCana, via the Climate Change Working Group of the Canadian Association of Petroleum Producers, will continue to work with the Federal and Alberta Governments to develop an approach to deal with climate change issues which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

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, development of 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 and completion 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 reservoir pressure or productivity, 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;
- timing and amount of operating and maintenance 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 is exposed to risks associated with the use of current technology, and the pursuit of new technology, which could negatively affect its results of operations.

Current steam-assisted gravity drainage technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process can also vary and affect costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on EnCana's results of operations.

There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

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 indirect 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. The Gallo complaint claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

In addition, EnCana Corporation and WD, along with other energy companies, have been named as defendants in several other lawsuits filed in California (some of which are class actions and some of which are brought by individual parties on their own behalf). The California lawsuits relate to sales of natural gas in California from 1999 through 2002 and contain essentially similar allegations as in the Gallo complaint. Without admitting any liability in the lawsuits, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court, subject to final documentation and approval by the San Diego Superior Court. The actions against WD and EnCana Corporation brought by the individual parties and certain of the class actions filed in California that are currently before the United States District Court in Nevada are not included in this settlement.

WD is a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the New York Mercantile Exchange (NYMEX) during the period from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle all claims that are the subject of the lawsuit, subject to final documentation and approval by the New York District Court.

As is customary, the class actions do not 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 the remaining 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
Website: 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
Website: 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, 2005. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta. Information relating to reserves in this annual information form dated February 17, 2006 was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton as independent qualified reserves evaluators.

The principals of each of GLJ Petroleum Consultants 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, 2005.

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, 2005. The reserves data consist of the following:

   (i) estimated proved oil and gas reserve quantities as at December 31, 2005 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, 2005:

Evaluator and Preparation Date of Report	Reserves Location	Estimated Proved Reserve Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax,
		Gas	Liquids	10% discount rate
		(Bcf)	(MMbbl)	($USMM)
McDaniel & Associates Consultants Ltd. January 12, 2006	Canada	3,975	842.7	18,825
GLJ Petroleum Consultants Ltd. January 13, 2006	Canada	2,542	89.9	9,861
Netherland, Sewell & Associates, Inc. January 26, 2006	United States	4,326	48.9	14,656
DeGolyer and MacNaughton February 3, 2006	United States	941	4.1	2,619
GLJ Petroleum Consultants Ltd. January 13, 2006	Ecuador		135.0	2,335
Totals		11,784	1,120.6	48,296

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 judgments 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) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

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

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

February 13, 2006

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, 2005 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 13, 2006 (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) Randall K. Eresman
President & Chief Executive Officer

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

(signed) David P. O'Brien
Director and Chairman of the Board
February 14, 2006

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

APPENDIX C
Audit Committee Mandate
Last Updated August 22, 2005

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 independent directors pursuant to Multilateral Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("MI 52-110").

All members of the Committee shall be financially literate, as defined in MI 52-110, 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, directors' 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.

2005

Management s Discussion and Analysis

Management s Discussion and Analysis

This Management s Discussion and Analysis (MD&A) for EnCana Corporation (EnCana or the Company) should be read with the audited Consolidated Financial Statements for the year ended December 31, 2005, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2004. Readers should also read the Forward-Looking Statements legal advisory contained at the end of this MD&A. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) in United States dollars, except where another currency has been indicated.

This MD&A has been prepared in United States dollars. Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 16, 2006.

Readers can find the definition of certain terms used in this MD&A in the notes regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana at the end of this MD&A.

EnCana s Business

EnCana is a leading independent North American oil and gas company.

EnCana operates two continuing businesses:

Upstream includes the Company s exploration for and development and production of, natural gas, crude oil, and natural gas liquids (NGLs) and other related activities. The majority of the Company s Upstream operations are located in Canada and the United States. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and the Canadian East Coast; and

Market Optimization includes activities to enhance the sale of Upstream s production. As part of these activities Marketing buys and sells third party products that enhance EnCana s operating flexibility for transportation commitments, product type, delivery points and customer diversification.

2005 Review

EnCana pursues predictable, profitable growth from a portfolio of long-life resource plays in Canada and the United States. In 2005, EnCana:

Grew total sales volumes from continuing operations to 4,163 million cubic feet (MMcf) of gas equivalent per day (MMcfe/d), an increase of 5 percent over 2004;

Grew natural gas sales by 9 percent to 3,227 MMcf/d;

Achieved sales of approximately 51,000 barrels per day (bbls/d) in December 2005 at EnCana s three steam-assisted gravity drainage (SAGD) projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek increased from an average of 28,774 bbls/d in 2004 to approximately 40,000 bbls/d in December 2005, after completion of its expansion program in the fourth quarter of 2005;

Replaced approximately 213 percent of natural gas production and 406 percent of liquids production through reserves additions. Proved natural gas reserves totaled 11,784 billion cubic feet (Bcf) and proved liquids reserves totaled 1,120.6 million barrels (MMbbls) at December 31, 2005;

Made a substantial natural gas discovery below the Company s Cutbank Ridge resource play in British Columbia;

Purchased about 325,000 net undeveloped acres with multi-zone gas resource play potential in the Maverick Basin in Texas for $148 million;

Began construction of the Entrega natural gas pipeline out of the Piceance Basin in the U.S. Rockies; and

Sold Gulf of Mexico assets for net proceeds of approximately $1,472 million after-tax; sold its NGLs processing business for approximately $625 million; sold certain non-core conventional oil and gas assets for proceeds of approximately $471 million; and reached an agreement in principle to sell all interests in Ecuador for approximately $1,420 million.

EnCana enhances its ability to build shareholder value through financial discipline, strength and flexibility. In 2005 the Company:

Purchased 55.2 million common shares under the Normal Course Issuer Bid (NCIB) for a total cost of $1,924 million and renewed the NCIB until October 2006;

Redeemed nine issues of medium term notes for $1,036 million, including a $79 million after-tax charge to retire these notes;

Reduced long-term debt by $1,039 million to $6,703 million on December 31, 2005;

Split its common shares on a two-for-one basis; and

Improved its net debt to EBITDA ratio from 1.4x at December 31, 2004, to 1.1x at December 31, 2005.

Business Environment

Natural Gas

Natural Gas Price Benchmarks (Average for the period)	**Year ended December 31 2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
AECO Price *(C$/Mcf)*	**$ 8.48**	**25%**	$ 6.79	1%	$ 6.70
NYMEX Price *($/MMBtu)*	**8.62**	**40%**	6.14	14%	5.39
Rockies (Opal) Price *($/MMBtu)*	**6.96**	**33%**	5.23	27%	4.12
AECO/NYMEX Basis Differential *($/MMBtu)*	**1.59**	**75%**	0.91	40%	0.65
Rockies/NYMEX Basis Differential *($/MMBtu)*	**1.66**	**82%**	0.91	-28%	1.27

In 2005, prices increased with concern over North America s ability to grow gas supply despite high drilling levels. A warm summer across North America and a cold December in the U.S. Northeast increased demand for power and two successive hurricanes damaged gas supply infrastructure in the U.S. Gulf Coast. Combined with high oil prices these factors caused the NYMEX gas price to average $8.62/MMBtu in 2005, a 40 percent increase from 2004.

Higher average AECO gas prices in 2005 compared with 2004 can be attributed to increased NYMEX prices partially offset by increased AECO/NYMEX basis differentials in 2005 compared to 2004.

Crude Oil

Crude Oil Price Benchmarks (Average for the period $/bbl)	Year ended December 31 2005	2005 vs 2004	2004	2004 vs 2003	2003
WTI	**$ 56.70**	**37%**	$ 41.47	34%	$ 30.99
WTI/Maya Differential	**15.70**	**38%**	11.41	68%	6.80
WTI/Bow River Differential	**19.64**	**53%**	12.82	60%	8.01
WTI/OCP NAPO Differential (Ecuador)	**18.37**	**28%**	14.33	78%	8.06

Global demand for oil is now pushing world refining capacity limits, resulting in more frequent crude oil product price spikes and historically high refining margins. An active hurricane season resulted in substantial interruptions to U.S. Gulf Coast production and refineries, which added to the world-wide tightness in refining capacity. The hurricane damage to production facilities in the Gulf of Mexico required the release of strategic reserves of crude oil in the United States and Europe to prevent prices from increasing to even higher levels.

Year-over-year Canadian heavy oil differentials were 53 percent wider in absolute dollar terms mainly due to the higher price for West Texas Intermediate (WTI). The Bow River Blend average sales price for 2005 was 65 percent of WTI, compared to 69 percent of WTI in 2004, primarily due to very wide differentials in the early part of 2005. Bitumen field prices are normally at their weakest level each year in the fourth quarter due to seasonal fluctuations in asphalt and condensate prices. In December 2004 condensate prices were particularly high and the differential between WTI and heavy oil prices was wide, leading to very low field prices. In 2005, higher WTI and lower condensate premiums considerably strengthened the year-end field price.

U.S./Canadian Dollar Exchange Rates

	Year ended December 31 2005	2004	2003
Average U.S. / Canadian dollar exchange rate	**$ 0.825**	$ 0.768	$ 0.716
	$ 0.768	$ 0.716	$ 0.637

Average U.S. / Canadian dollar exchange rate for prior year			
Increase in capital, operating and administrative expenditures caused solely by fluctuations in exchange rates	**$ 5.70**	$ 5.20	$ 7.90

The impacts of currency fluctuations on EnCana s results should be considered when analyzing the Consolidated Financial Statements. The value of the Canadian dollar increased by 7.4 percent or $0.057 to an average of US$0.825 in 2005 from an average of US$0.768 in 2004 which was approximately 7.3 percent or $0.052 higher than the 2003 average value. As a result, EnCana reported an additional $5.70 of costs for every hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices which are closely tied to the value of the U.S. dollar.

Acquisitions and Divestitures

In keeping with EnCana s North American resource play strategy, the Company completed the following significant divestitures in 2005:

The sale of its natural gas liquids processing business on December 13 for approximately $625 million subject to post-closing adjustments;

The sale of certain non-core Canadian conventional oil and gas assets on June 30 which were producing approximately 6,400 barrels of oil equivalent per day (BOE/d) for approximately $321 million; and

The sale of its Gulf of Mexico assets on May 26 for approximately $2.1 billion in cash. The net proceeds were approximately $1.5 billion after-tax and other adjustments. These assets were in the development and appraisal stage and accordingly there was no production.

Proceeds from these divestitures were directed primarily to a combination of debt reduction and the purchase of shares under EnCana s NCIB.

On November 21, 2005 EnCana announced that it had reached an agreement to sell its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. The sale is subject to closing conditions and regulatory approvals and is expected to close in the first quarter of 2006.

On September 13, 2005 EnCana announced that it had reached an agreement in principle to sell all of its shares in subsidiaries with oil and pipeline interests in Ecuador for approximately $1.42 billion. The sale will have an effective date of July 1, 2005 and is subject to other closing conditions and regulatory approvals. The sale, originally expected to close in 2005, is now expected to close in the first quarter of 2006.

EnCana is in the process of divesting of its natural gas storage business and expects to close the transaction in the second quarter of 2006.

During 2005 EnCana spent approximately $420 million to acquire undeveloped landholdings and minor amounts of natural gas production in the Fort Worth and East Texas key resource play areas in the United States.

Consolidated Financial Results

	Year ended December 31				
($ millions, except per share(1) amounts)	**2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Total Consolidated					
Cash Flow[2]	**$ 7,426**	**49%**	$ 4,980	12%	$ 4,459
- per share - diluted	**8.35**	**57%**	5.32	14%	4.65
Net Earnings [3]	**3,426**	**-2%**	3,513	49%	2,360
- per share - basic	**3.95**	**3%**	3.82	53%	2.49
- per share - diluted	**3.85**	**3%**	3.75	52%	2.46
Operating Earnings[4]	**3,241**	**64%**	1,976	41%	1,399
- per share diluted	**3.64**	**73%**	2.11	45%	1.46
Total Assets	**34,148**	**9%**	31,213	29%	24,110
Long-Term Debt	**6,703**	**-13%**	7,742	27%	6,088
Cash Dividends	**238**	**30%**	183	32%	139
Continuing Operations					
Cash Flow from Continuing Operations[2]	**6,962**	**55%**	4,502	10%	4,102
Net Earnings from Continuing Operations	**2,829**	**35%**	2,093	-2%	2,138
- per share - basic	**3.26**	**44%**	2.27	1%	2.25
- per share - diluted	**3.18**	**42%**	2.24		2.23
Operating Earnings from Continuing Operations [4]	**3,048**	**63%**	1,872	39%	1,346
Revenues, Net of Royalties	**14,266**	**39%**	10,259	20%	8,521

(1) Per share amounts have been restated for the effect of the common share split in 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under Cash Flow .

(3) 2005 Net Earnings include an after-tax gain of $370 million on the sale of EnCana s natural gas liquids processing business, 2004 includes an after-tax gain of $1,364 million on the sale of EnCana s U.K. operations and 2003 includes an after-tax gain of $169 million on the sale of pipeline operations.

(4) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings .

Cash Flow

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

2005 vs 2004

EnCana s total 2005 cash flow was $7,426 million, an increase of $2,446 million or 49 percent from 2004. This increase reflects higher commodity prices in 2005 partially reduced by increased costs. EnCana s discontinued operations contributed $464 million to cash flow compared with $478 million in 2004.

EnCana s 2005 cash flow from continuing operations was $6,962 million, an increase of $2,460 million or 55 percent from 2004.

The increase resulted from:

Average North American natural gas prices, excluding financial hedges, increased 36 percent to $7.46 per Mcf in 2005 compared to $5.47 per Mcf for 2004;

North American natural gas sales volumes increased 9 percent to 3,227 MMcf/d; and

Average North American liquids prices, excluding financial hedges, increased 26 percent to $36.17 per bbl in 2005 compared to $28.77 per bbl in 2004.

The increase in cash flow was partially reduced by:

Operating expenses which increased 31 percent to $1,438 million in 2005 compared with $1,099 million in 2004;

Interest expense which increased $126 million to $524 million in 2005. Almost all of this increase represents the cost to redeem certain notes in 2005; and

The current tax provision, excluding income tax on the sale of assets, increased $67 million to $626 million compared with $559 million in 2004.

Realized financial commodities hedge losses were $441 million after-tax in 2005, relatively unchanged from $430 million after-tax in 2004.

2004 vs 2003

EnCana s total 2004 cash flow was $4,980 million, an increase of $521 million or 12 percent from 2003. This increase reflects the net impact of higher prices and growth in sales volumes reduced by realized financial hedge losses and increased costs. EnCana s discontinued operations contributed $478 million to cash flow compared with $357 million in 2003.

EnCana s 2004 cash flow from continuing operations was $4,502 million, an increase of $400 million or 10 percent from 2003.

The increase resulted from:

Average North American natural gas prices, excluding financial hedges, increased 12 percent to $5.47 per Mcf in 2004 compared to $4.87 per Mcf in 2003;

North American natural gas sales volumes increased 16 percent to 2,968 MMcf/d; and

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

The increase in cash flow was partially reduced by:

Realized financial commodity hedge losses which increased $234 million to $430 million after-tax in 2004 from $196 million after-tax in 2003;

Operating expenses which increased 14 percent to $1,099 million in 2004 compared with $965 million in 2003;

Interest expense which increased $114 million to $398 million in 2004 as a result of increased long-term debt primarily as a result of the acquisition of Tom Brown, Inc. (TBI); and

The current income tax provision which increased by $678 million to $559 million compared with a recovery of $119 million in 2003.

Net Earnings

2005 vs 2004

EnCana s 2005 total net earnings were $3,426 million compared with $3,513 million in 2004. Net earnings from discontinued operations decreased $823 million to $597 million; most of this decrease results from the 2005 after-tax gain of $370 million on the sale of substantially all of EnCana s natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana s U.K. operations.

EnCana s 2005 net earnings from continuing operations were $2,829 million, an increase of $736 million or 35 percent compared with 2004. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

An increase in depreciation, depletion and amortization (DD&A) of $390 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;

Unrealized mark-to-market losses of $311 million after-tax in 2005 compared with losses of $117 million in 2004; and

A $92 million after-tax unrealized foreign exchange gain on Canadian issued U.S. dollar debt in 2005 compared with a $229 million gain in 2004.

2004 vs 2003

EnCana s total 2004 net earnings were $3,513 million compared with $2,360 million in 2003. Discontinued operations contributed $1,420 million to net earnings in 2004, including an after-tax gain of $1,364 million on the sale of EnCana s U.K. operations.

EnCana s 2004 net earnings from continuing operations were $2,093 million, a decrease of $45 million or 2 percent compared with 2003. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

An increase in DD&A of $412 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes;

Unrealized mark-to-market losses of $117 million after-tax in 2004, the first year when unrealized mark-to-market amounts were recognized in net earnings;

A $229 million after-tax unrealized foreign exchange gain on Canadian issued U.S. dollar debt in 2004 compared with a $433 million after-tax gain in 2003; and

Future tax recoveries due to a tax rate reduction of $109 million in 2004 compared with $359 million in 2003.

Operating Earnings

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust net earnings and net earnings from continuing operations by non-operating items that Management believes reduce the comparability of the Company s underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations has been prepared to provide investors with information that is more comparable between years.

Summary of Total Operating Earnings

	Year ended December 31				
($ millions)	**2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Net Earnings, as reported	**$ 3,426**	**-2%**	$ 3,513	49%	$ 2,360
Deduct: Gain on discontinuance, after-tax	**370**		1,364		169
Add: Unrealized mark-to-market accounting loss, after-tax	**(277)**		(165)		
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**92**		229		433
Deduct: Future tax recovery due to tax rate reductions			109		359
Operating Earnings (2) (4)	**$ 3,241**	**64%**	$ 1,976	41%	$ 1,399
($per Common Share - Diluted)					
Net Earnings, as reported	**$ 3.85**	**3%**	$ 3.75	52%	$ 2.46
Deduct: Gain on discontinuance, after-tax	**0.42**		1.46		0.18
Add: Unrealized mark-to-market accounting loss, after-tax	**(0.31)**		(0.18)		
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**0.10**		0.24		0.45

Deduct: Future tax recovery due to tax rate reductions					0.12			0.37
Operating Earnings (2) (4)	**$**	**3.64**	**73%**	$	2.11	45%	$	1.46

Summary of Operating Earnings from Continuing Operations

($ millions)	2005	2005 vs 2004	2004	2004 vs 2003	2003
	Year ended December 31				
Net Earnings from Continuing Operations, as reported	**$ 2,829**	**35%**	$ 2,093	-2%	$ 2,138
Add: Unrealized mark-to-market accounting loss, after-tax	**(311)**		(117)		
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**92**		229		433
Deduct: Future tax recovery due to tax rate reductions			109		359
Operating Earnings from Continuing Operations (3) (4)	**$ 3,048**	**63%**	$ 1,872	39%	$ 1,346

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years.

(2) 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 or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) 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 after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(4) Unrealized gains or losses have no impact on cash flow.

Results of Operations

Upstream Operations

Financial Results from Continuing Operations

Year ended December 31 ($ millions)	2005 Produced Gas	2005 Crude Oil and NGLs	2005 Other	2005 Total	2004 Produced Gas	2004 Crude Oil and NGLs	2004 Other	2004 Total	2003 Produced Gas	2003 Crude Oil and NGLs	2003 Other	2003 Total
Revenues, Net of Royalties	**$ 8,418**	**$ 1,764**	**$ 283**	**$ 10,465**	$ 5,704	$ 1,320	$ 232	$ 7,256	$ 4,447	$ 1,170	$ 180	$ 5,797
Expenses												
Production and mineral taxes	**401**	**52**		**453**	270	41		311	153	11		164
Transportation and selling	**465**	**60**		**525**	416	56		472	360	69		429

Operating	**733**	**305**	**313**	**1,351**	519	285	222	1,026	402	300	170	872
Operating Cash Flow	**$ 6,819**	**$ 1,347**	**$ (30)**	**$ 8,136**	$ 4,499	$ 938	$ 10	$ 5,447	$ 3,532	$ 790	$ 10	$ 4,332
Depreciation, depletion and amortization				**2,688**				2,271				1,900
Upstream Income				**$ 5,448**				$ 3,176				$ 2,432

Upstream Revenues

2005 vs 2004

Revenues, net of royalties, increased in 2005 for the following reasons:

A 36 percent increase in natural gas prices combined with a 9 percent increase in natural gas sales volumes; and

A 26 percent increase in liquids prices.

Revenues, net of royalties, increases were reduced by:

A 6 percent decrease in liquids volumes mainly as a result of property dispositions in the first and third quarters of 2004 and in June 2005.

Realized financial commodity hedging losses totalled $672 million in 2005 and were relatively unchanged from $669 million in 2004.

2004 vs 2003

Revenues, net of royalties, increased in 2004 for the following reasons:

A 12 percent increase in natural gas prices combined with a 16 percent increase in natural gas sales volumes; and

A 27 percent increase in liquids prices.

Revenues, net of royalties, increases were reduced by:

Realized financial commodity and currency hedging losses totalled $669 million in 2004 compared to $297 million in 2003.

Revenue Variances for 2005 Compared to 2004 from Continuing Operations

Year ended December 31 ($ millions)	2004 Revenues, Net of Royalties	Revenue Variances in: Price(1)	Volume	2005 Revenues, Net of Royalties
Produced Gas				
Canada	$ 3,928	$ 1,488	$ 70	$ 5,486
United States	1,776	557	599	2,932
Total Produced Gas	$ 5,704	$ 2,045	$ 669	$ 8,418
Crude Oil and NGLs				
Canada	$ 1,155	$ 491	$ (127)	$ 1,519
United States	165	61	19	245
Total Crude Oil and NGLs	$ 1,320	$ 552	$ (108)	$ 1,764

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 82 percent of the increase in revenues, net of royalties, in 2005 compared with 2004. The balance of the increase in revenues results from an increase in sales volumes.

The increase in produced gas volumes in Canada in 2005 was mainly due to drilling success in the key resource plays of Cutbank Ridge in northeast British Columbia and Shallow Gas and Coalbed Methane (CBM) in central and southern Alberta. Dispositions of mature conventional producing assets during the first and third quarters of 2004 and natural production declines reduced the impact of these increases on total volumes.

The increase in produced gas volumes in the U.S. resulted from the Tom Brown, Inc. (TBI) acquisition in May 2004 and drilling success at Jonah, Piceance, Fort Worth and East Texas.

The dispositions of mature Canadian conventional producing assets during the first and third quarters of 2004 and in June 2005 and natural production declines resulted in crude oil and NGLs volume reductions. These volume reductions were mitigated by increased production from the Pelican Lake heavy oil project.

Upstream Sales Volumes

Sales Volumes

	Year ended December 31				
	2005	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Produced Gas *(MMcf/d)*	**3,227**	**9%**	2,968	16%	2,553
Crude Oil *(bbls/d)*	**130,418**	**-7%**	140,379	-1%	142,326
NGLs *(bbls/d)*	**25,582**	**-2%**	26,038	10%	23,569
Continuing Operations *(MMcfe/d)* [(1)]	**4,163**	**5%**	3,966	12%	3,548
Discontinued Operations					
Ecuador *(bbls/d)*	**71,065**	**-9%**	77,993	68%	46,521
United Kingdom *(BOE/d)* [(2)]		**-100%**	20,973	71%	12,295
Syncrude *(bbls/d)*					7,629
Discontinued Operations *(MMcfe/d)* [(1)]	**426**	**-28%**	594	49%	399
Total *(MMcfe/d)* [(1)]	**4,589**	**1%**	4,560	16%	3,947

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

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

Sales volumes from continuing operations increased in 2005 by 5 percent or 197 MMcfe/d for the following reasons:

Production from EnCana s key resource plays increased approximately 18 percent for natural gas and 15 percent for crude oil;

Drilling success in the key resource gas plays of Cutbank Ridge, Shallow Gas, CBM, Jonah, Piceance, Fort Worth and East Texas;

Successful waterflood response at the Pelican Lake heavy oil project;

Greater Sierra volumes have decreased in 2005 compared to 2004 due to the timing and pace of development drilling as well as delays in well tie-ins caused by weather issues in the earlier part of 2005; and

Significant Canadian property dispositions in the first and third quarters of 2004 and June 2005 were offset somewhat by the full year impact of the TBI acquisition in May 2004. As a result, the net impact of acquisition and disposition activity in 2005 only reduced sales volumes by approximately 11 MMcfe/d.

Key Resource Plays

	Daily Production					Drilling Activity Number of Net Wells Drilled		
	2005	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**	**2005**	**2004**	**2003**
Natural Gas (MMcf/d)								
Jonah	**435**	**12%**	389	4%	374	**104**	70	59
Piceance	**307**	**18%**	261	73%	151	**266**	250	284
East Texas	**90**	**80%**	50			**84**	50	
Fort Worth	**70**	**159%**	27	286%	7	**59**	36	5
Greater Sierra	**219**	**-5%**	230	61%	143	**164**	187	199
Cutbank Ridge	**92**	**130%**	40	1233%	3	**135**	50	20
CBM	**57**	**235%**	17	325%	4	**1,084**	760	267
Shallow Gas	**625**	**6%**	592	17%	507	**1,267**	1,552	2,366
Oil (Mbbls/d)								
Foster Creek	**29**		29	32%	22	**39**	11	8
Pelican Lake	**26**	**37%**	19	19%	16	**52**	92	134
Total (MMcfe/d)	**2,224**	**18%**	1,892	34%	1,416	**3,254**	**3,058**	**3,342**

Per Unit Results - Produced Gas

Year ended December 31

($ per thousand cubic feet)	**Canada 2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**	**United States 2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Price	**$ 7.27**	**36%**	$ 5.34	10%	$ 4.87	**$ 7.82**	**35%**	$ 5.79	19%	$ 4.88
Expenses										
Production and mineral taxes	**0.10**	**25%**	0.08	14%	0.07	**0.81**	**25%**	0.65	38%	0.47
Transportation and selling	**0.36**	**-8%**	0.39	3%	0.38	**0.46**	**48%**	0.31	-23%	0.40
Operating	**0.67**	**29%**	0.52	8%	0.48	**0.53**	**43%**	0.37	32%	0.28
Netback	**$ 6.14**	**41%**	$ 4.35	10%	$ 3.94	**$ 6.02**	**35%**	$ 4.46	20%	$ 3.73
Gas Sales Volumes *(MMcf/d)*	**2,132**	**2%**	2,099	7%	1,965	**1,095**	**26%**	869	48%	588

2005 vs 2004

EnCana s realized natural gas prices for 2005 were $7.46 per Mcf, an increase of 36 percent compared with 2004. North American realized financial commodity hedging losses on natural gas for 2005 were approximately $377 million or $0.32 per Mcf compared to losses of approximately $238 million or $0.22 per Mcf in 2004.

Natural gas per unit production and mineral taxes in the U.S. increased $0.16 per Mcf or 25 percent in 2005 compared to 2004 as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 48 percent or $0.15 per Mcf for 2005 compared to 2004 primarily as a result of marketing TBI and Fort Worth gas volumes downstream of the wellhead in 2005.

Canadian natural gas per unit operating expenses for 2005 were 29 percent or $0.15 per Mcf higher compared to 2004 as a result of increased industry activity, the higher value of the Canadian dollar, higher repairs and maintenance and long-term compensation expenses. Natural gas per unit operating expenses in the U.S. increased 43 percent or $0.16 per Mcf for 2005 compared to 2004 mainly as a result of increased staffing levels attributable to growth, higher long-term compensation expenses, increased industry activity and higher workovers.

2004 vs 2003

EnCana s realized natural gas prices for 2004 were $5.47 per Mcf, an increase of 12 percent compared with 2003. North American realized financial commodity hedging losses on natural gas for 2004 were approximately $238 million or $0.22 per Mcf compared to losses of approximately $91 million or $0.10 per Mcf in 2003. Certain of the 2004 hedges were put in place to secure the economics of the TBI acquisition and will expire in December 2006.

Natural gas per unit production and mineral taxes in the U.S. increased 38 percent or $0.18 per Mcf in 2004 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. decreased 23 percent or $0.09 per Mcf in 2004 compared to 2003 primarily as a result of the TBI acquisition where a majority of the production was sold at the wellhead and did not incur transportation charges.

Canadian natural gas per unit operating expenses for 2004 were 8 percent or $0.04 per Mcf higher compared to 2003 primarily due to the higher value of the Canadian dollar. The increase in the U.S. natural gas per unit operating expenses of 32 percent or $0.09 per Mcf in 2004 compared to 2003 was a result of higher operating costs at properties acquired as part of the TBI acquisition, incremental operating costs associated with waste water disposal in Colorado and other non-recurring charges related to 2003.

Per Unit Results - Crude Oil

Year ended December 31

		North America			
($ per barrel)	**2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Price	**$ 34.15**	**22%**	$ 27.92	25%	$ 22.29
Expenses					
Production and mineral taxes	**0.58**	**41%**	0.41	356%	0.09
Transportation and selling	**1.20**	**13%**	1.06	-19%	1.31
Operating	**6.44**	**16%**	5.53	-5%	5.80
Netback	**$ 25.93**	**24%**	$ 20.92	39%	$ 15.09
Crude Oil Sales Volumes *(bbls/d)*	**130,418**	**-7%**	140,379	-1%	142,326

2005 vs 2004

The increase in the average crude oil price in 2005, excluding the impact of financial hedges, reflects the 37 percent increase in the benchmark WTI in 2005. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 53 percent). North American realized financial commodity hedging losses on crude oil were approximately $295 million or $5.18 per bbl of liquids in 2005 compared to losses of approximately $431 million or $7.08 per bbl of liquids in 2004.

Heavy oil sales in 2005 increased to 64 percent of total oil sales from 60 percent in 2004. This increase was mainly due to an increase in heavy oil production from the Pelican Lake property combined with dispositions of non-core conventional assets in 2004 and 2005 producing light/medium oil.

North American crude oil per unit production and mineral taxes increased by 41 percent or $0.17 per bbl in 2005 compared to 2004 primarily due to the impact of higher prices.

The 2005 crude oil per unit transportation and selling expenses in North America increased 13 percent or $0.14 per bbl mainly due to the higher value of the Canadian dollar and increased tariff rates as of July 2005.

North American crude oil per unit operating costs for 2005 increased 16 percent or $0.91 per bbl compared to 2004 mainly due to the higher value of the Canadian dollar, workovers, repairs and maintenance, fuel costs and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana s other properties increased the overall crude oil per unit operating costs.

2004 vs 2003

The increase in the average crude oil price in 2004, excluding the impact of financial hedges, reflects the 34 percent increase in the benchmark WTI in 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 60 percent). North American realized financial commodity hedging losses on crude oil were approximately $431 million or $7.08 per bbl of liquids in 2004 compared to losses of approximately $206 million or $3.41 per bbl of liquids in 2003.

Heavy oil sales in 2004 decreased to 60 percent of total oil sales from 62 percent in 2003. This decrease was mostly due to the sale of Petrovera and other non-core conventional assets in 2004 reduced slightly by higher heavy oil production from Foster Creek and Pelican Lake.

North American crude oil per unit production and mineral taxes in 2004 increased 356 percent or $0.32 per bbl compared to 2003 primarily as a result of mineral tax amendments related to prior years that were recorded in the third quarter of 2003. In addition, there were higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to the Alberta freehold mineral tax and Saskatchewan resource tax.

The 2004 crude oil per unit transportation and selling expenses in North America decreased 19 percent or $0.25 per bbl mainly due to an adjustment in oil transportation rates.

North American crude oil per unit operating costs for 2004 decreased 5 percent or $0.27 per bbl from 2003 mainly due to the sale of Petrovera, which had higher operating costs than other properties. This reduction was partially offset by the effect of the higher value of the Canadian dollar and higher fuel gas costs for the SAGD projects.

Per Unit Results - NGLs

Year ended December 31

	Canada					United States				
($ per barrel)	**2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**	**2005**	**2005 vs 2004**	**2004**	**2004 vs 2003**	**2003**
Price	**$ 44.24**	**41%**	$ 31.43	30%	$ 24.26	**$ 48.36**	**36%**	$ 35.43	31%	$ 26.97
Expenses										
Production and mineral taxes						**4.86**	**27%**	3.82	88%	2.03
Transportation and selling	**0.42**	**2%**	0.41	141%	0.17	**0.01**				
Netback	**$ 43.82**	**41%**	$ 31.02	29%	$ 24.09	**$ 43.49**	**38%**	$ 31.61	27%	$ 24.94
NGLs Sales Volumes *(bbls/d)*	**11,907**	**-11%**	13,452	-6%	14,278	**13,675**	**9%**	12,586	35%	9,291

2005 vs 2004

The increase in NGLs realized prices in 2005 generally correlates with strong WTI oil prices.

U.S. NGLs per unit production and mineral taxes for 2005 increased by 27 percent or $1.04 per bbl compared to 2004 as a result of the increase in NGLs prices.

2004 vs 2003

The increase in NGLs realized prices in 2004 generally correlate with strong WTI oil prices.

U.S. NGLs per unit production and mineral taxes in 2004 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.

Upstream Depreciation, Depletion and Amortization

2005 vs 2004

DD&A expenses in 2005 increased by $417 million or 18 percent for the following reasons:

- Sales volumes increased 5 percent;

- On a continuing operations basis, unit of production DD&A rates were $1.72 per Mcfe in 2005 compared to $1.53 per Mcfe in 2004. Rates increased in 2005 as a result of the higher value of the Canadian dollar and increased future development costs reduced by the effect of the 2005 Gulf of Mexico sale; and

- DD&A expense in 2005 included impairments of $7 million related to exploration prospects in Yemen and other areas.

2004 vs 2003

DD&A expenses in 2004 increased by $371 million or 20 percent for the following reasons:

- Sales volumes increased 12 percent;

- On a continuing operations basis, unit of production DD&A rates were $1.53 per Mcfe in 2004 compared to $1.39 per Mcfe in 2003. Rates increased in 2004 as a result of the higher value of the Canadian dollar and the impact of the acquisition of TBI; and

- DD&A expense in 2004 included impairments of $23 million related to exploration prospects in Ghana, Bahrain and other areas.

Market Optimization

Financial Results

Year ended December 31

($ millions)

		2005	2005 vs 2004		2004	2004 vs 2003		2003
Revenues	$	**4,267**	**33%**	$	3,200	18%	$	2,722
Expenses								
Transportation and selling		**13**	**-28%**		18	-62%		47
Operating		**85**	**15%**		74	-20%		93
Purchased product		**4,159**	**35%**		3,092	20%		2,572
Operating Cash Flow	$	**10**	**-38%**	$	16	60%	$	10
Depreciation, depletion and amortization		**8**	**-83%**		47	81%		26
Segment Income (Loss)	$	**2**	**106%**	$	(31)	-94%	$	(16)

2005 vs 2004

Revenues and purchased product expenses increased in 2005 compared to 2004 as a result of increases in commodity prices while third party optimization volumes remained relatively flat year over year.

In December, EnCana and Valero Energy Corporation completed their previously announced study of the conversion of Valero s Lima, Ohio refinery to refine Canadian heavy oil and decided not to proceed with the project. During 2005, EnCana expensed approximately $6 million of conversion study expenses.

2004 vs 2003

Revenues and purchased product expenses increased in 2004 compared with 2003 as a result of increases in commodity prices.

In 2004, a $35 million writedown in the values of EnCana s equity investment interest in the Trasandino Pipeline in Argentina and Chile increased DD&A expenses.

Corporate

Financial Results

Year ended December 31

($ millions)

	2005	2004	2003
Revenues	**$ (466)**	$ (197)	$ 2
Expenses			
Operating	**2**	(1)	
Depreciation, depletion and amortization	**73**	61	41
Segment Loss	**$ (541)**	$ (257)	$ (39)
Administrative	**268**	197	173
Interest, net	**524**	398	284
Accretion of asset retirement obligation	**37**	22	17
Foreign exchange (gain) loss, net	**(24)**	(412)	(603)
Stock-based compensation - options	**15**	17	18
(Gain) on divestitures		(59)	(1)

2005 corporate revenues include approximately $466 million in unrealized mark-to-market losses related to financial commodity contracts compared with $197 million in 2004.

Price volatility has had a significant impact on the earnings impact of EnCana s price risk management activities. On December 31, 2005 the forward price curve for 2006 had increased from December 31, 2004 by 56 percent to $63.19 per bbl for WTI and 73 percent to $10.77 per Mcf for NYMEX gas.

Summary of Unrealized Mark-to-Market Gains (Losses)

	Year ended December 31	
($ millions)	**2005**	**2004(1)**
Continuing Operations		
Natural Gas	**$ (494)**	$ (21)
Crude Oil	**28**	(177)
	(466)	(198)
Expenses	**3**	(7)
	(469)	(191)
Income tax recovery	**158**	74
	$ (311)	$ (117)

(1) Effective January 1, 2004 outstanding derivative instruments were recorded using mark-to-market accounting when EnCana adopted amendments to Canadian accounting standards.

2005 vs 2004

DD&A includes provisions for corporate assets such as computer equipment, office furniture and leasehold improvements.

Administrative expenses increased $71 million compared to 2004. The increase results from higher long-term compensation expenses that are tied to EnCana s common share price and the change in the U.S./Canadian dollar exchange rate. Administrative costs in 2005 were $0.18 per Mcfe compared with $0.14 per Mcfe in 2004.

Interest expense in 2005 increased as a result of a $121 million ($79 million after-tax) charge to retire certain medium term notes. EnCana s total long-term debt decreased by $1,154 million to $6,776 million at December 31, 2005 compared with $7,930 million at December 31, 2004. EnCana s 2005 weighted average interest rate on outstanding debt was 5.3 percent, up from an average of approximately 4.9 percent in 2004 as a result of increased interest rates in the marketplace.

The foreign exchange gain of $24 million in 2005 includes $113 million ($92 million after-tax) resulting from the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada. Under Canadian GAAP, EnCana is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana s monetary assets and liabilities.

2004 vs 2003

The increase in DD&A expense in 2004 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 $24 million in 2004. The increase results from the change in the U.S./Canadian dollar exchange rate and increased long-term compensation expenses. Administrative costs were $0.14 per Mcfe in 2004 compared to $0.13 per Mcfe in 2003.

The higher interest expense resulted primarily from the higher average outstanding debt level during the year arising from 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 which partially mitigated the effect of increased debt.

The majority of the foreign exchange gain of $412 million in 2004 resulted from the change in the U.S./Canadian dollar exchange rate in 2004 applied to U.S. dollar denominated debt issued in Canada.

During 2004, EnCana recorded gains of $59 million on the sale of certain corporate investments.

Income Tax

2005 vs 2004

The effective tax rate for 2005 was 30.8 percent compared with 23.2 percent in 2004. The 2005 income tax provision has been reduced by the net benefit of tax basis retained on dispositions of $68 million compared to $169 million in 2004. The 2004 effective tax rate included 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.

Current tax expense was $1,204 million in 2005 compared to $559 million in 2004; $578 million of this increase relates to the sale of Gulf of Mexico assets and has been shown as cash outflow from investing activities in the Statement of Cash Flows. The balance of $626 million has been included in cash flow.

2004 vs 2003

The effective tax rate for 2004 was 23.2 percent compared to 14.1 percent for 2003.

In 2003, future income taxes were reduced by $359 million as a result of reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the Canadian federal resource allowance deduction.

Further information regarding EnCana s effective tax rate can be found in Note 8 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 which are subject to tax, either current or future. 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 values;

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 or losses; and

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

EnCana s operations are complex and related tax interpretations, regulations and legislation in the various jurisdictions in which 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

($ millions)	Year ended December 31 2005	2004	2003
Upstream	**$ 6,202**	$ 4,343	$ 3,845
Market Optimization	**197**	10	5
Corporate	**78**	46	57
Total Core Capital Expenditures	**$ 6,477**	$ 4,399	$ 3,907
Acquisitions	**448**	2,952	540
Dispositions	**(2,523)**	(1,709)	(301)
Discontinued Operations	**(305)**	(1,436)	(724)
Net Capital Investment	**$ 4,097**	$ 4,206	$ 3,422

EnCana s capital investment was funded by cash flow from operations, proceeds from dispositions in excess of amounts paid for purchases of common shares under the NCIB and repayments of long-term debt. The Company s core capital expenditures increased approximately $2.1 billion to $6.5 billion in 2005.

Upstream Capital Expenditures

2005 vs 2004

Capital spending during 2005 was primarily focused on North American resource play land capture, drilling programs and facility expansion. Natural gas capital expenditures were focused on continued development of the Company s key resource plays in Greater Sierra, Cutbank Ridge, Coalbed Methane and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2005 was concentrated on expansion of the Company s SAGD projects located at Foster Creek and Christina Lake, the waterflood program at Pelican Lake in Alberta and Weyburn in Saskatchewan. In addition, capital was directed at identifying and developing new resource plays at Bighorn and Borealis.

The $1.9 billion increase in Upstream core capital expenditures in 2005 compared to 2004 was primarily due to:

Canadian core capital expenditures increased approximately $1.1 billion to $4.2 billion. This includes approximately $219 million related to the change in the U.S./Canadian dollar exchange rate as well as the following factors:

Crown land sales and other land costs in 2005 were $281 million higher than the prior year mainly due to significantly higher land prices;

Drilling and completion costs increased $731 million in 2005 due to service cost increases as a result of industry activity levels;

Facility costs increased $189 million in 2005 mainly due to the Foster Creek expansion which was completed in the fourth quarter of 2005;

In Canada, the Company drilled 4,038 net wells in 2005 compared to 4,385 net wells in 2004. This decrease of 8 percent relates mainly to decreased drilling of shallow gas wells in southern and west-central Alberta due to weather related delays during the summer and service sector shortages as a result of record levels of activity in the industry.

U.S. core capital expenditures increased $0.7 billion in 2005 to $2.0 billion primarily due to increases in drilling and completion costs. In the U.S. the Company drilled 617 net wells in 2005 compared to 534 net wells in 2004, an increase of 16 percent. Drilling was focused on continued development of the four key resource plays of Jonah, Piceance, Fort Worth and East Texas.

2004 vs 2003

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 increase in Upstream capital expenditures in 2004 compared to 2003 reflects increased drilling and development activities in the U.S. The impact of the increased average U.S./Canadian dollar exchange rate resulted in an increase to Canadian dollar denominated core capital expenditures of approximately $230 million.

EnCana drilled 4,923 net wells in 2004 compared to 5,581 net wells in 2003.

Canadian East Coast

EnCana continues to examine the economic viability of the Deep Panuke project. In 2005, EnCana participated in one offshore exploration well at Grand Pre and a sidetrack well in the Grand Pre licence in an attempt to extend the northeast boundary of the Deep Panuke field. Both wells were abandoned in January 2006. Negotiations continue with the Government of Nova Scotia regarding the terms of development for Deep Panuke.

Brazil

Appraisal drilling on the offshore BM-C-7 block resulted in the identification of a viable field. In November 2005 an agreement was reached to dispose of the Company s 50 percent interest in the field for approximately $350 million. In the October 2005 bid round, EnCana acquired a working interest in two non-operated blocks, which were officially awarded in January 2006. As of December 31, 2005 the Company had invested approximately $106 million in Brazil.

Market Optimization Capital Expenditures

Expenditures in 2005 were mostly focused on construction activities underway for the Entrega pipeline from Meeker Hub, Colorado to Wamsutter, Wyoming. Material portions of the pipeline construction were completed in December.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. The increase in spending in 2005 includes land purchased for the development of a Calgary office complex.

Acquisitions and Dispositions

Acquisitions included minor property acquisitions in 2005 and 2004 as well as the TBI acquisition in 2004.

Dispositions in 2005 include the sale of:

- Gulf of Mexico assets;

- Substantially all of EnCana s natural gas liquids processing business; and
- Certain non-core Canadian conventional oil and gas assets.

Dispositions in 2004 include the sale of:

- U.K. operations;
- Non-core conventional oil and gas assets;
- Petrovera Resources; and
- EnCana s interest in the Alberta Ethane Gathering system.

Proved Oil and Gas Reserves

Proved Reserves by Country

Constant Prices After Royalties

As at December 31	Natural Gas 2005	2005 vs 2004	2004	2004 vs 2003	2003	Crude Oil and NGLs[1] 2005	2005 vs 2004[2]	2004	2004 vs 2003	2003
	(billions of cubic feet)					(millions of barrels)				
Canada	**6,517**	**12%**	5,824	11%	5,256	**932.5**	**48%**	629.6		629.4
United States	**5,267**	**14%**	4,636	48%	3,129	**53.1**	**-42%**	91.0	119%	41.6
Ecuador						**135.0**	**-6%**	143.3	-11%	161.7
United Kingdom				-100%	26				-100%	124.5
Total	**11,784**	**13%**	10,460	24%	8,411	**1,120.6**	**30%**	863.9	-10%	957.2

(1) Crude Oil and NGLs include condensate.

(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to bitumen price at year-end 2004.

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. 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, 2005.

Natural Gas

EnCana s proved natural gas reserves as at December 31, 2005, on an SEC constant price basis, totalled 11,784 Bcf. Approximately 213 percent of 2005 production was replaced by reserves additions during 2005. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 2,541 Bcf. Downward revisions of 58 Bcf were less than 1 percent of natural gas reserves at the beginning of 2005. In Canada, positive revisions of 202 Bcf (or 3.5 percent of the opening balance) were largely associated with coalbed methane. Downward revisions in the United States amounted to 260 Bcf (or 5.6 percent of reserves at the beginning of 2005), the majority of which were the result of reduced reserve estimates per well in the southern Rockies. Acquisitions in the U.S. mid-continent essentially offset divestitures of non-core properties in the Gulf of Mexico and Canadian Plains.

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Crude Oil and NGLs

The Company s proved crude oil and natural gas liquids reserves as at December 31, 2005, on an SEC constant price basis, totalled 1,120.6 MMbbls. Reserve additions replaced over 400 percent of production. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 167.2 MMbbls while revisions amounted to 227.0 MMbbls. Foster Creek accounted for the majority of these reserves additions. In addition, prices at December 31, 2005 allowed the reinstatement of 362.7 million barrels of bitumen that were recorded as a downward revision at year-end 2004 due to anomalously low bitumen prices on December 31, 2004. The sale of non core properties in the Gulf of Mexico and Canadian Plains accounted for the majority of the 54.1 million barrels of divestitures.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties

	Natural Gas (billions of cubic feet)			**Crude Oil and NGLs(1) (millions of barrels)**			
As at December 31, 2005	**Canada**	**USA**	**Total**	**Canada**	**USA**	**Ecuador**	**Total**
Beginning of year	5,824	4,636	10,460	266.9	91.0	143.3	501.2
Revisions and improved recovery	202	(260)	(58)	222.1	(3.2)	8.1	227.0
Extensions and discoveries	1,289	1,252	2,541	148.1	8.9	10.2	167.2
Acquisitions	7	76	83		0.4		0.4
Divestitures	(30)	(37)	(67)	(15.1)	(39.0)		(54.1)
Production	(775)	(400)	(1,175)	(52.2)	(5.0)	(26.6)	(83.8)
	6,517	5,267	11,784	569.8	53.1	135.0	757.9

End of year before reinstatement of bitumen reserves							
Reinstatement of bitumen reserves[2]				362.7			362.7
End of year	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6

(1) Crude Oil and NGLs include condensate.

(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to the bitumen price at year-end 2004.

Discontinued Operations

Discontinued operations in the Consolidated Financial Statements include:

Upstream

Ecuador

United Kingdom

Midstream

EnCana s 2005 net earnings from discontinued operations were $597 million compared to $1,420 million in 2004 and include realized financial hedge losses of $86 million after-tax and unrealized financial hedge gains of $34 million after-tax.

EnCana s 2004 net earnings from discontinued operations were $1,420 million compared to $222 million in 2003 and include realized commodity hedge losses of $278 million after-tax (2003: $12 million after-tax) and unrealized financial hedge losses of $48 million after-tax.

Summary information is presented below. Additional information concerning EnCana s discontinued operations can be found in Note 4 to EnCana s Consolidated Financial Statements.

Ecuador

	Year ended December 31		
	2005	**2004**	**2003**
Sales volumes			
Crude Oil *(bbls/d)*	**71,065**	77,993	46,521
($ millions)			
Net Earnings (loss) from Discontinued Operations	**$ 131**	$ (33)	$ 32
Capital Investment	**179**	240	367

In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

On September 13, 2005 EnCana announced it had reached an agreement in principle to sell all its interests in Ecuador operations for $1.42 billion which is approximately equivalent to the asset s net book value at July 1, 2005, the referenced effective date of the transaction. All economic benefits occurring after the July 1, 2005 effective date accrue to the purchaser. A provision of $234 million has been recorded against the net book value to recognize management s best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments at the sales date, as required under Canadian generally accepted accounting principles.

2005 vs 2004

Production volumes in 2005 averaged 72,916 bbls/d; down 5 percent from 2004. Sales volumes in 2005 decreased 9 percent to average 71,065 bbls/d due to declining production in Tarapoa and Block 15 as well as the shift to an underlift position at December 31, 2005 from an overlift position at the end of 2004.

Production and mineral taxes were $70 million higher in 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. EnCana is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

2004 vs 2003

Production volumes for 2004 averaged 76,872 bbls/d; up 50 percent from 2003. Sales volumes in 2004 increased 68 percent to average 77,993 bbls/d. The higher sales volumes are primarily due to the combination of available capacity on the OCP pipeline in Ecuador, which commenced shipments in September 2003, 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 sales volumes from the Tarapoa block.

Contingency information regarding certain disputed items with the Ecuadorian government relating to value-added tax (VAT), ownership of Block 15 and deductibility of interest is included in Note 4 to EnCana s Consolidated Financial Statements.

United Kingdom

	Year ended December 31		
	2005	**2004**	**2003**
Sales volumes			
Produced Gas *(MMcf/d)*		30	13
Crude Oil *(bbls/d)*		14,128	9,231
NGLs *(bbls/d)*		1,845	897
Total *(BOE/d)*		20,973	12,295
($ millions)			
Net Earnings (loss) from Discontinued Operations	**$ 35**	$ 1,338	$ (7)
Capital Investment		488	223

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.

Midstream

	Year ended December 31		
($ millions)	**2005**	**2004**	**2003**
Net Earnings from Discontinued Operations	**$ 431**	$ 118	$ 173
Capital Investment	**21**	88	271

2005 vs 2004

On December 13, 2005 EnCana sold substantially all of its natural gas liquids processing business for proceeds of approximately $625 million subject to post closing adjustments. EnCana continues with plans to divest its natural gas storage operations which include the AECO storage facility as well as storage facilities in the United States.

Net earnings in 2005 for the discontinued Midstream businesses were $431 million, an increase of $313 million over 2004. Included in 2005 net earnings is a $370 million gain on the sale of the natural gas liquids processing business. 2005 net earnings have been reduced by $30 million as a result of agreements by WD Energy Services Inc., one of EnCana s indirect subsidiaries, to settle certain California and New York lawsuits, as further described in this MD&A under the heading Contractual Obligations and Contingencies.

2004 vs 2003

2004 net earnings of $118 million were $55 million lower than 2003.

In 2003 EnCana closed the previously announced sales of its crude oil pipeline business resulting in a $169 million after-tax gain on the sales.

Liquidity and Capital Resources

Operating Activities

	Year ended December 31		
($ millions)	**2005**	**2004**	**2003**
Net cash provided by (used in)			
Operating activities	**$ 7,430**	$ 4,591	$ 4,304
Investing activities	**(4,520)**	(4,259)	(3,729)
Financing activities	**(3,396)**	163	(542)
Deduct: Foreign exchange loss on cash and cash equivalents held in foreign currency	**2**	6	10
(Decrease) increase in cash and cash equivalents	**(488)**	489	23

Cash flow from continuing operations was $6,962 million, an increase of $2,460 million from 2004. The increase in cash flow in 2005 was primarily due to increased revenues driven by higher commodity prices and sales volumes partially reduced by increased expenses. Cash flow from continuing operations comprises most of EnCana s cash provided by operating activities.

Investing Activities

Net cash of $4,520 million was used for investing activities in 2005, an increase of $261 million compared to 2004. Capital expenditures, including property acquisitions, increased $2,162 million in 2005. This increase occurred as a result of:

- The increased value of the Canadian dollar;
- Increased crown land purchase prices and other land costs;
- Higher drilling and completion costs;
- Increased facility costs as a result of the Foster Creek expansion; and
- Entrega pipeline construction costs.

EnCana s 2004 activities included the $2,335 million TBI acquisition. EnCana did not undertake any business combinations in 2005.

EnCana s divestments of the Gulf of Mexico assets, certain mature conventional properties and the natural gas liquids processing facilities generated $3.1 billion less tax of $578 million in 2005. In 2004, EnCana s divestments of the U.K. operations, certain mature conventional properties, Petrovera Resources and its interest in the Alberta Ethane Gathering System generated proceeds of $3.6 billion.

Financing Activities

Total long-term debt decreased by $1,154 million to $6,776 million in 2005 from the $7,930 million in 2004. EnCana s net debt adjusted for working capital was $7,970 million as at December 31, 2005 compared with $7,184 million at December 31, 2004. During 2005 EnCana purchased 60.7 million of its Common Shares for a total consideration of $2.1 billion. Working capital at December 31, 2005 was a deficit of $1,267 million. This compares to working capital of $558 million as at December 31, 2004.

Continuity of long-term debt

	2005		
Date	**Description**		**Amount**
Repayment of long-term debt			
January	TBI Debt [1]	**$**	**(1)**
August	8.50% due March 15, 2011 [1]		**(42)**
August	6.20% due June 23, 2028 [1]		**(42)**
September	5.95% due October 1, 2007 [1]		**(166)**
September	5.95% due June 2, 2008 [1]		**(83)**
September	5.80% due June 19, 2008 [1]		**(83)**
September	6.10% due June 1, 2009 [1]		**(125)**
September	7.15% due December 17, 2009 [1]		**(125)**
September	7.10% due October 11, 2011 [1]		**(166)**
September	7.30% due September 2, 2014 [1]		**(125)**
November	8.75% Debentures due November 9, 2005		**(146)**
		$	**(1,104)**
Issuances of long-term debt			
September	3.60% due September 15, 2008	**$**	**429**
		$	**429**
Other			
	Net decrease in revolving term debt	**$**	**(538)**
	Other non cash items		**59**
		$	**(479)**
Increase (reduction) in total long term debt		**$**	**(1,154)**

	2004		
Date	**Description**		**Amount**
Repayment of long-term debt			
March	7.00% Term Securities due March 23, 2034	$	(97)
June	6.60% due June 30, 2004		(39)
August	8.50% Preferred Securities due September 30, 2048 [1]		(155)
September	9.50% Preferred Securities due September 30, 2048 [1]		(150)
December	7.00% due December 1, 2004		(77)
December	8.40% due December 15, 2004		(73)

Various	TBI Debt [1]		(407)
Various	Bridge Facility [2]		(1,761)
		$	(2,759)
Issuances of long-term debt			
May	5.80% due May 1, 2014	$	1,000
August	6.50% due August 15, 2034		750
August	4.60% due August 15, 2009		250
Various	Bridge Facility [2]		1,761
		$	3,761
Other			
	Net increase in revolving term debt	$	72
	Debt acquired in TBI acquisition		408
	Other non cash items		73
		$	553
Increase (reduction) in total long term debt			1,555

(1) Redeemed prior to maturity

(2) Bridge Facility used to fund the acquisition of TBI

EnCana had available unused committed bank credit facilities in the amount of $3.0 billion and unused shelf prospectuses for up to $3.4 billion at December 31, 2005.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor s has assigned a rating of A- with a Negative Outlook , Dominion Bond Rating Services has assigned a rating of A(low) with a Stable Trend and Moody s has assigned a rating of Baa2 Stable .

Financial Metrics

	December 31 2005	**December 31 2004**
Net Debt to Capitalization	**33%**	33%
Net Debt to EBITDA[1]	**1.1x**	1.4x

(1) EBITDA is a non-GAAP measure that is defined as earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, acccretion of asset retirement obligation, and depreciation, depletion, and amortization.

Net Debt to Capitalization and Net Debt to EBITDA are two ratios Management uses to steward the Company s overall debt position as measures of the Company s overall financial strength.

Outstanding Share Data

(millions)	2005[1]	December 31 2004[1]	2003[1]
Outstanding, beginning of year	**900.6**	921.2	957.8
Issued under option plans	**15.0**	19.4	11.0
Shares purchased (Normal Course Issuer Bid)	**(55.2)**	(40.0)	(47.6)
Shares purchased (Performance Share Unit Plan)	**(5.5)**		
Common shares outstanding, end of period	**854.9**	900.6	921.2
Weighted average common shares outstanding - diluted	**889.2**	936.0	959.4

(1) The number of common shares outstanding prior to the 2 for 1 share split has been restated for comparison.

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. There were no Preferred Shares outstanding.

EnCana s shareholders approved a split of the Company s outstanding Common Shares on a two-for-one basis at its Annual and Special Meeting held on April 27, 2005. Each shareholder received one additional Common Share for each Common Share held on the record date of May 12, 2005.

Employees and directors have been granted options to purchase Common Shares under various plans. On October 26, 2005 EnCana terminated the directors stock option plan. At December 31, 2005, 20.7 million options, without Tandem Share Appreciation Rights attached, were outstanding of which 16.8 million are exercisable.

Long-term incentives granted to EnCana employees include a reduced level of stock option grants that is supplemented by grants of Performance Share Units (PSUs). PSUs will not result in the issue of new Common Shares by the Company. Shares purchased for the PSUs plan are held in a Trust for future vesting. Stock options granted in 2004 and 2005 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 based upon the employee s choice at the time of exercise.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under four consecutive NCIBs which commenced in October 2002 and may continue until October 30, 2006. Between October 2002 and December 31, 2005 EnCana has purchased 142.8 million shares for cancellation under these Bids for a total cost of $3,796 million. EnCana is entitled to purchase for cancellation up to approximately 85.6 million Common Shares under the renewed NCIB which commenced on October 31, 2005 and will terminate not later than October 30, 2006. As of January 31, 2006 EnCana has purchased 6.8 million shares under this NCIB. Under the prior NCIB which commenced October 29, 2004 and expired October 28, 2005, EnCana purchased approximately 84.2 million Common Shares. Shareholders may obtain a copy of the NCIB documents without charge at www.sedar.com or by contacting investor.relations@encana.com.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $238 million in 2005, $183 million in 2004 and $139 million in 2003. These dividends are funded by cash flow. At December 31, 2005 the quarterly dividend paid to shareholders was $0.075 per Common Share (2004: $0.050; 2003: C$0.050).

Normal Course Issuer Bid

	Share Purchases(1) Year ended December 31	
(millions)	2005	2004
Bid expired October 2004		11.0
Bid expired October 2005	**55.2**	29.0
Bid expiring October 2006		
	55.2	40.0

(1) Transactions that occurred before the 2 for 1 share split have been restated for comparison.

Contractual Obligations and Contingencies

	Expected Payment Date				
($ millions)	**2006**	**2007 to 2008**	**2009 to 2010**	**2011+**	**Total**
Long-Term Debt	$ 73	$ 864	$ 450	$ 5,325	$ 6,712
Asset Retirement Obligations	1	10	9	4,924	4,944
Pipeline Transportation	339	560	404	850	2,153
Purchase of Goods and Services	230	357	138	33	758
Operating Leases(2)	48	86	65	132	331
Product Purchases	33	45	44	98	220
Capital Commitments	92	29		38	159
Total	$ 816	$ 1,951	$ 1,110	$ 11,400	$ 15,277
Product Sales	$ 61	$ 132	$ 82	$ 300	$ 575
Discontinued operations (3)	$ (331)	$ 67	$ 161	$ 793	$ 690
Financial Contracts and Other Commitments	$ (76)	$ 4	$	$	$ (72)

(1) In addition, the Company has made commitments related to its risk management program. See Note 16 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 15 to the Consolidated Financial Statements.

(2) Related to office space.

(3) Primarily related to long-term transportation commitments.

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana s total long-term debt commitments of $6,712 million at December 31, 2005 are $1,425 million in commitments related to Banker s Acceptances and Commercial Paper. 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. Further details regarding EnCana s long-term debt are described in Note 12 to the Consolidated Financial Statements.

As at December 31, 2005, EnCana 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 149 Bcf at a weighted average price of $3.85 per Mcf. At December 31, 2005, these transactions had an unrealized loss of $464 million.

Contingency information regarding certain disputed items with the Ecuadorian government relating to VAT, ownership of Block 15 and deductibility of interest is included in Note 4 to EnCana s Consolidated Financial Statements.

Off-Balance Sheet Financing Arrangements

EnCana does not have any off-balance sheet financing 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, EnCana leases office space for personnel who support field operations and for corporate purposes.

Legal Proceedings

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

Discontinued Merchant Energy Operations

California

As disclosed previously, 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 whereby 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.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits 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.

In all but one of the class actions in the United States District Court and in the Gallo action, decisions dealing with the issue of whether the scope of the Federal Energy Regulatory Commission s exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims are on appeal to the United States Court of Appeals for the Ninth Circuit.

Without admitting any liability in the lawsuits, in November 2005, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD is also a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle the New York class action lawsuit subject to final documentation and approval by the New York District Court.

Based on the aforementioned settlements, during the fourth quarter of 2005 a total of $30 million has been recorded in Administrative expenses in Net Earnings from Discontinued Operations. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding 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

No changes in accounting principles were adopted in 2005.

Recent Accounting Pronouncements

Management is assessing the following new and revised accounting pronouncements that have been issued and are not yet effective:

In the quarter ending March 31, 2006 EnCana will adopt Section 3831 Non-Monetary Transactions issued by the Canadian Institute of Chartered Accountants (CICA) in June 2005. Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Company does not expect application of this new standard to have a material impact on its consolidated financial statements.

In the year ending December 31, 2007 EnCana will be required to adopt Section 1530 Comprehensive Income , Section 3251 Equity , Section 3855 Financial Instruments - Recognition and Measurement and Section 3865 Hedges issued by the CICA in January 2005. Under the new standards: a new financial statement, Comprehensive Income has been introduced that will provide for certain gains and losses, including foreign currency translation adjustment and other amounts arising from changes in fair value to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives are to be included on EnCana s balance sheet and measured at fair values in most cases. Requirements for hedge accounting have been further clarified. Although the Company is in the process of evaluating the impact of these standards, it does not expect the Financial Instruments and Hedges standards to have a material impact on its consolidated financial statements as it currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.

Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada ratified in January 2006. As part of that plan, accounting standards in Canada for public companies will converge with International Financial Report Standards (IFRS) over the next five years. EnCana continues to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

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. A summary of EnCana s significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates 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 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 the 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 Alberta Energy Company and the acquisition of TBI, is assessed by EnCana 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 EnCana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company s policy is to not use derivative financial instruments for speculative purposes.

The Company enters into financial transactions to help 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.

EnCana may also use derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of its 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.

EnCana 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.

EnCana 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 and 2005, the Company elected not to designate any of its current price risk management activities as accounting hedges and accordingly, accounts for all derivatives using the mark-to-market accounting method.

Pensions and Other Post Retirement Benefits

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

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

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.

EnCana 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

Sensitivity of 2006 Net Earnings From Continuing Operations and Cash Flow From Continuing Operations (Including Hedges)[(1) (2)]

Sensitivity of 2006 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**
$	1.00 per million British thermal units increase in the NYMEX gas price	$ 520	$ 760
$	6.00 per barrel increase in the WTI oil price	130	180
$	0.01 decrease in the U.S.\Canadian dollar exchange rate	5	40

(1) Hedge position as at December 31, 2005.

(2) Based on forward curve commodity price and forward curve estimates dated December 31, 2005.

Sensitivity of 2006 Net Earnings From Continuing Operations and Cash Flow From Continuing Operations (Excluding Hedges)(1)

Sensitivity of 2006 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**
$1.00 per million British thermal units increase in the NYMEX gas price	$ 780	$ 980
$6.00 per barrel increase in the WTI oil price	130	180
$0.01 decrease in the U.S.\Canadian dollar exchange rate	5	40

(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2005.

EnCana 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 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. EnCana does not use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of December 31, 2005, are disclosed in Note 16 to the Consolidated Financial Statements.

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 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 EnCana 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, EnCana 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 gain of $71 million.

EnCana 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 $70 million.

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, purchased call options to allow participation at higher WTI levels, three-way put spreads and put options.

Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, EnCana 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.

EnCana 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. EnCana 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

EnCana is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company s credit portfolio and with credit practices that limit transactions to counterparties of investment grade credit quality and transactions that are fully collateralized. A substantial portion of EnCana s accounts receivable is with customers in the oil and gas industry.

Operational Risks

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 EnCana s capital program with the results and identified learnings shared across the Company.

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.

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

Environment, Health, Safety and Security Risks

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana 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 recommends approval of 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 protect EnCana s personnel and assets. EnCana has established an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana s operations.

Climate Change

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 6 percent below 1990 levels over the period 2008 2012. There is currently no clear direction post 2012. The previous Federal Government released a framework outlining its Climate Change action plan on April 13, 2005. The plan as released contains few technical details regarding the implementation of the Government s greenhouse gas reduction strategy.

Prior to the recent change in the Federal Government, the implementation of the Climate Change plan had yet to be finalized, therefore EnCana is unable to predict the total impact of the potential regulations upon its business. However, a July 16, 2005 Canada Gazette notice partially addressed the uncertainty associated with a greenhouse gas regulation for existing facilities by providing the oil and gas sector with limits on cost (a price assurance mechanism of $15/tonne for compliance) and emission reductions targets that will not exceed 12 percent lower than business as usual levels of total covered emissions for a given sector. It also made a commitment to targets based on the best technology economically achievable for new facilities. Based on these commitments and EnCana s activity on geological sequestration of CO_2, we do not anticipate that the cost implications of government climate change plans will have a material impact on operations or future growth plans.

The ultimate impact of Canada s implementation plan, however, remains subject to numerous risks and uncertainties, including the outcome of discussions between the recently elected Federal Government, provincial governments, the resulting legislation, the emission reduction target obligations among economic sectors, and other administrative details. The Climate Change Working Group of the Canadian Association of Petroleum Producers will continue to work 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.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana s greenhouse gas emissions will be available in the Corporate Responsibility Report that will be published in the second quarter of 2006. The Report will be available on www.encana.com.

Reputational Risks

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.

Quarterly Results

Quarterly Summary

	2005				**2004**			
($ millions, except per share(1) amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Total Consolidated								
Cash Flow(2)	**$ 2,510**	**$ 1,931**	**$ 1,572**	**$ 1,413**	$ 1,491	$ 1,363	$ 1,131	$ 995
- per share - diluted	**2.88**	**2.20**	**1.76**	**1.55**	1.60	1.46	1.21	1.07
Net Earnings (Loss)	**2,366**	**266**	**839**	**(45)**	2,580	393	250	290
- per share - basic	**2.77**	**0.31**	**0.96**	**(0.05)**	2.81	0.43	0.27	0.31
- per share - diluted	**2.71**	**0.30**	**0.94**	**(0.05)**	2.77	0.42	0.27	0.31
Operating Earnings(3)	**1,271**	**704**	**655**	**611**	573	559	379	465
- per share - diluted	**1.46**	**0.80**	**0.73**	**0.67**	0.62	0.60	0.41	0.50
Continuing Operations								

Cash Flow from Continuing Operations(2)	**2,390**	**1,823**	**1,502**	**1,247**	1,358	1,256	1,029	859
Net Earnings (Loss) from Continuing Operations	**1,869**	**348**	**774**	**(162)**	1,055	463	270	305
- per share - basic	**2.19**	**0.41**	**0.89**	**(0.18)**	1.15	0.50	0.29	0.33
- per share - diluted	**2.14**	**0.40**	**0.87**	**(0.18)**	1.13	0.50	0.29	0.33
Operating Earnings from Continuing Operations(3)	**1,229**	**733**	**611**	**475**	513	555	368	436
Revenues, Net of Royalties	**5,860**	**2,982**	**3,386**	**2,038**	3,542	2,195	2,374	2,148

(1) Per share amounts have been restated for the effect of the common share split in 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under Cash Flow .

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings .

Natural gas prices in the fourth quarter of 2005 were higher than the same period in 2004. A cold December in the U.S. Northeast combined with continued supply losses from hurricane damage and high crude oil prices caused NYMEX gas prices to remain high through the fourth quarter.

The WTI crude oil price was 24 percent higher in the fourth quarter of 2005 than the same period in 2004. An active hurricane season resulted in substantial interruptions to the U.S. Gulf Coast production and refineries. The hurricane damage prompted the United States and Europe to release emergency supplies into the market, which prevented prices from increasing to even higher levels. Fourth quarter Canadian heavy oil differentials were wider in dollar terms relative to the fourth quarter of 2004, primarily due to the higher price for WTI.

EnCana s net earnings for the fourth quarter of 2005 were $2,366 million, down $214 million from 2004. Net earnings from discontinued operations decreased $1,028 million to $497 million; most of this decrease results from the 2005 after-tax gain on the sale of substantially all of EnCana s natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana s U.K. operations.

EnCana s net earnings from continuing operations in the fourth quarter of 2005 increased $814 million or 77 percent to $1,869 million compared with the same period in 2004. The increase resulted from:

Average North American natural gas prices, excluding financial hedges, increased 69 percent to $10.29 per Mcf, compared to $6.08 per Mcf in 2004;

Average North American liquids prices, excluding financial hedges, increased 23 percent to $37.16 per bbl in 2005 compared to $30.20 in 2004;

Natural gas sales volumes increased 8 percent from the comparable period in 2004 to 3,326 MMcf/d; and

Unrealized financial commodity hedging gains of $661 million after-tax in 2005 compared with $411 million after-tax in 2004.

The increase in net earnings from continuing operations was reduced by:

Realized financial commodity hedging losses of $229 million after-tax compared with $145 million after-tax in 2004;

Operating expenses increased 46 percent to $452 million in 2005 compared with $309 million in 2004. The increase in the average U.S./Canadian dollar exchange rate in 2005, increased workovers, repairs and maintenance, higher electrical costs and rising costs as a result of increased industry activity were significant reasons for this increase; and

A $21 million after-tax foreign exchange loss on Canadian issued U.S. dollar debt in 2005 compared to a $131 million after-tax unrealized foreign exchange gain in 2004; this reflects the quarter-end decrease in the value of the Canadian dollar in 2005 compared to a quarter-end increase in the same period in 2004.

During the fourth quarter of 2005, EnCana:

Sold substantially all of the natural gas liquids processing business on December 13, 2005 for proceeds of approximately $625 million subject to post-closing adjustments;

Announced an agreement on November 21, 2005 to sell the 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million;

Repaid long-term debt of $145 million; and

Received regulatory approval to renew its Normal Course Issuer Bid. EnCana did not purchase any shares to December 31, 2005 under this renewed Bid.

Quarterly Sales Volumes

	2005				**2004**			
	Q4	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *(MMcf/d)*	**3,326**	**3,222**	**3,212**	**3,146**	3,087	3,096	3,001	2,684
Crude Oil *(bbls/d)*	**134,178**	**124,402**	**132,294**	**130,826**	132,061	142,506	144,347	142,669
NGLs *(bbls/d)*	**25,111**	**26,055**	**24,814**	**26,358**	27,409	27,167	26,340	23,208
Continuing Operations *(MMcfe/d)*(1)	**4,282**	**4,125**	**4,155**	**4,089**	4,044	4,114	4,025	3,679
Discontinued Operations								
Ecuador *(bbls/d)*	**69,943**	**68,710**	**73,176**	**72,487**	77,876	74,846	78,303	80,982
United Kingdom *(BOE/d)*(2)					13,927	20,222	26,728	22,755
Discontinued Operations *(MMcfe/d)*(1)	**419**	**412**	**439**	**435**	551	570	630	623
Total *(MMcfe/d)*(1)	**4,701**	**4,537**	**4,594**	**4,524**	4,595	4,684	4,655	4,302

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

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

Outlook

EnCana plans to continue to focus principally on growing natural gas production from unconventional resource plays in North America.

EnCana will also continue to develop its high quality in-situ oilsands resources and will continue to evaluate marketing options that will help expand their development.

Volatility in crude oil prices is expected to continue throughout 2006 as a result of market uncertainties over supply and refining disruptions on the U.S. Gulf Coast, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. North American conventional gas supply has peaked in the past two years and EnCana believes that unconventional resource plays can offset conventional gas production declines. The industry s ability to respond to the gas supply constrained situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2006 core capital investment program to be funded from cash flow.

Proceeds from the sales of non-core properties are expected to be used to reduce debt and for purchases under the Company s NCIB program.

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.

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 or information (collectively referred to herein as forward-looking statements) within the meaning of the safe harbour provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as anticipate , believe , expect , plan , intend , forecast , target , project or similar 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: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands development; projected production volumes in 2006 for natural gas, crude oil and NGLs in Canada and the United States; projections relating to the volatility of crude oil prices in 2006 and beyond and the reasons therefor; the Company s projected capital investment levels for 2006 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; the impact of the Kyoto Accord on operating costs; the adequacy of the Company s provision for taxes; the impact of changes in accounting principles on future consolidated financial statements; the Company s plans to divest of its natural gas storage business and Ecuador operations, and projections relating to the use of proceeds therefrom, including debt repayment and purchases under its Normal Course Issuer Bid. 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 and assumptions regarding oil and gas prices; assumptions based upon EnCana s current guidance; 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; risks associated with technology; 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 necessarily represent value equivalency at the well head.

Resource Play, Estimated Ultimate Recovery, Unbooked Resource Potential, Total Resource Portfolio and Total Resource Life

EnCana uses the terms resource play, estimated ultimate recovery, unbooked resource potential, total resource portfolio and total resource life. 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 (EUR) 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. EnCana defines Unbooked Resource Potential as quantities of oil and gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play potential and areal extent. Consequently, EnCana s unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

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 $0.85 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 per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and EBITDA 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, refer 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.

CONSOLIDATED FINANCIAL

STATEMENTS

Prepared in US$

For the Year Ended December 31, 2005

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 Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York 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)
Randall K. Eresman
President &
Chief Executive Officer

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

February 6, 2006

AUDITORS REPORT

To the Shareholders of EnCana Corporation

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2005 and December 31, 2004 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2005. 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, 2005 and December 31, 2004 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

(signed)

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

Canada

February 6, 2006

U.S. Dollars

EnCana Corporation

Consolidated Statement of Earnings

($ millions, except per share amounts)		For the years ended December 31, **2005**	**2004**	**2003**
Revenues, Net of Royalties	*(Note 3)*			
Upstream		**$ 10,465**	$ 7,256	$ 5,797
Market Optimization		**4,267**	3,200	2,722
Corporate - Unrealized (loss) gain on risk management		**(466)**	(198)	
- Other			1	2
		14,266	10,259	8,521
Expenses	*(Note 3)*			
Production and mineral taxes		**453**	311	164
Transportation and selling		**538**	490	476
Operating		**1,438**	1,099	965
Purchased product		**4,159**	3,092	2,572
Depreciation, depletion and amortization		**2,769**	2,379	1,967
Administrative		**268**	197	173
Interest, net	*(Note 6)*	**524**	398	284
Accretion of asset retirement obligation	*(Note 13)*	**37**	22	17
Foreign exchange (gain) loss, net	*(Note 7)*	**(24)**	(412)	(603)
Stock-based compensation - options	*(Note 14)*	**15**	17	18
(Gain) on divestitures	*(Note 5)*		(59)	(1)
		10,177	7,534	6,032
Net Earnings Before Income Tax		**4,089**	2,725	2,489
Income tax expense	*(Note 8)*	**1,260**	632	351
Net Earnings From Continuing Operations		**2,829**	2,093	2,138
Net Earnings From Discontinued Operations	*(Note 4)*	**597**	1,420	222
Net Earnings		**$ 3,426**	$ 3,513	$ 2,360
Net Earnings From Continuing Operations per Common Share	*(Note 17)*			
Basic		**$ 3.26**	$ 2.27	$ 2.25
Diluted		**$ 3.18**	$ 2.24	$ 2.23
Net Earnings per Common Share	*(Note 17)*			
Basic		**$ 3.95**	$ 3.82	$ 2.49
Diluted		**$ 3.85**	$ 3.75	$ 2.46

Consolidated Statement of Retained Earnings

($ millions)	For the years ended December 31, **2005**	**2004**	**2003**

Retained Earnings, Beginning of Year		**$**	**7,935**	$	5,276	$	3,523
Net Earnings			**3,426**		3,513		2,360
Dividends on Common Shares			**(238)**		(183)		(139)
Charges for Normal Course Issuer Bid	*(Note 14)*		**(1,642)**		(671)		(468)
Retained Earnings, End of Year		**$**	**9,481**	$	7,935	$	5,276

See accompanying notes to Consolidated Financial Statements.

U.S. Dollars

EnCana Corporation

Consolidated Balance Sheet

($ millions)		**As at December 31, 2005**	**2004**
Assets			
Current Assets			
Cash and cash equivalents		**$ 105**	$ 593
Accounts receivable and accrued revenues		**1,851**	1,566
Risk management	*(Note 16)*	**495**	317
Inventories	*(Note 9)*	**103**	58
Assets of discontinued operations	*(Note 4)*	**1,050**	971
		3,604	3,505
Property, Plant and Equipment, net	*(Notes 3, 10)*	**24,881**	22,503
Investments and Other Assets	*(Note 11)*	**496**	334
Risk Management	*(Note 16)*	**530**	87
Assets of Discontinued Operations	*(Note 4)*	**2,113**	2,325
Goodwill		**2,524**	2,459
	(Note 3)	**$ 34,148**	$ 31,213
Liabilities and Shareholders Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,741**	$ 1,742
Income tax payable		**392**	357
Risk management	*(Note 16)*	**1,227**	224
Liabilities of discontinued operations	*(Note 4)*	**438**	436
Current portion of long-term debt	*(Note 12)*	**73**	188
		4,871	2,947
Long-Term Debt	*(Note 12)*	**6,703**	7,742
Other Liabilities		**93**	118
Risk Management	*(Note 16)*	**102**	192
Asset Retirement Obligation	*(Note 13)*	**816**	611
Liabilities of Discontinued Operations	*(Note 4)*	**267**	213
Future Income Taxes	*(Note 8)*	**5,289**	5,082
		18,141	16,905
Commitments and Contingencies	*(Note 18)*		
Shareholders Equity			
Share capital	*(Note 14)*	**5,131**	5,299
Share options, net			10
Paid in surplus		**133**	28
Retained earnings		**9,481**	7,935
Foreign currency translation adjustment		**1,262**	1,036
		16,007	14,308
		$ 34,148	$ 31,213

See accompanying notes to Consolidated Financial Statements.

Approved by the Board

(signed)	(signed)
David P. O'Brien	Barry W. Harrison
Director	Director

U.S. Dollars

EnCana Corporation

Consolidated Statement of Cash Flows

($ millions)		For the years ended December 31, 2005	2004	2003
Operating Activities				
Net earnings from continuing operations		$ **2,829**	$ 2,093	$ 2,138
Depreciation, depletion and amortization		**2,769**	2,379	1,967
Future income taxes	*(Note 8)*	**56**	73	470
Cash tax on sale of assets	*(Note 8)*	**578**		
Unrealized loss on risk management	*(Note 16)*	**469**	191	
Unrealized foreign exchange (gain)		**(50)**	(285)	(545)
Accretion of asset retirement obligation	*(Note 13)*	**37**	22	17
(Gain) on divestitures	*(Note 5)*		(59)	(1)
Other		**274**	88	56
Cash flow from continuing operations		**6,962**	4,502	4,102
Cash flow from discontinued operations		**464**	478	357
Cash flow		**7,426**	4,980	4,459
Net change in other assets and liabilities		**(281)**	(176)	(84)
Net change in non-cash working capital from continuing operations	*(Note 17)*	**497**	1,565	(744)
Net change in non-cash working capital from discontinued operations		**(212)**	(1,778)	673
		7,430	4,591	4,304
Investing Activities				
Business combinations	*(Note 2)*		(2,335)	
Capital expenditures	*(Note 3)*	**(6,925)**	(4,763)	(4,356)
Proceeds on disposal of assets	*(Note 5)*	**2,523**	1,456	301
Cash tax on sale of assets		**(578)**		
Corporate (acquisitions)	*(Note 5)*			(91)
Equity investments			47	(6)
Net change in investments and other		**(109)**	44	(16)
Net change in non-cash working capital from continuing operations	*(Note 17)*	**330**	(29)	(112)
Discontinued operations		**239**	1,321	551
		(4,520)	(4,259)	(3,729)
Financing Activities				
Net (repayment) issuance of revolving long-term debt		**(538)**	72	288
Repayment of long-term debt		**(1,104)**	(2,759)	(142)
Issuance of long-term debt		**429**	3,761	500
Issuance of common shares	*(Note 14)*	**294**	281	114
Purchase of common shares	*(Note 14)*	**(2,114)**	(1,004)	(868)
Dividends on common shares		**(238)**	(183)	(139)
Other		**(125)**	(5)	(13)
Discontinued operations				(282)

		(3,396)		163		(542)
Deduct: Foreign Exchange Loss on Cash and Cash Equivalents Held in Foreign Currency		**2**		6		10
(Decrease) Increase in Cash and Cash Equivalents		**(488)**		489		23
Cash and Cash Equivalents, Beginning of Year		**593**		104		81
Cash and Cash Equivalents, End of Year	**$**	**105**	$	593	$	104
Supplemental Cash Flow Information *(Note 17)*						

See accompanying notes to Consolidated Financial Statements.

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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 19.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana s exploration and production business and 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.

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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.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana 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 for the defined benefit pension plan 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

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period covers the expected 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. Investment tax credits are recorded as an offset to the related expenditures.

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 without tandem share appreciation rights attached 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 without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached 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, including internal costs and asset retirement 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.

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

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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.

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 and Market Optimization

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. Land is carried at cost.

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 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

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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. 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 that do not have tandem share appreciation rights attached to them granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes-Merton option-pricing model. Compensation costs are recognized over the vesting period.

Obligations for payments, cash or common shares, under the Company s share appreciation rights, options with tandem share appreciation rights, deferred share units and performance share units plans are accrued as compensation expense over the vesting period. Fluctuations in the price of EnCana s common shares 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.

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S) Recent Accounting Pronouncements

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

Beginning with the year ending December 31, 2007 the Company will be required to adopt the Canadian Institute of Chartered Accountants (CICA) Section 1530 Comprehensive Income , Section 3251 Equity , Section 3855 Financial Instruments Recognition and Measurement , and Section 3865 Hedges , which were issued in January 2005. Under the new standards a new financial statement, Consolidated Statement of Other Comprehensive Income, has been introduced that will provide for certain gains and losses, including foreign currency translation adjustment and other amounts arising from changes in fair value to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives are to be included in the Company s Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. Although EnCana is in the process of evaluating the impact of these standards, the Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.

Beginning with the first quarter of 2006, the Company will adopt CICA Section 3831 Non-Monetary Transactions . Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. EnCana does not expect application of this new standard to have a material impact on its Consolidated Financial Statements.

For the next five years CICA will adopt its new strategic plan for the direction of accounting standards in Canada, which was ratified in January 2006. As part of that plan, accounting standards in Canada for public companies will converge with International Financial Report Standards (IFRS) over the next five years. The Company continues to monitor and assess the impact of convergence of Canadian GAAP with IFRS.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2005.

NOTE 2. BUSINESS COMBINATION

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.

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The calculation of the purchase price and the allocation to assets and liabilities is shown below:

Calculation of Purchase Price:		
Cash paid for common shares of TBI	$	2,341
Transaction costs		13
Total purchase price	$	2,354
Plus: Fair value of liabilities assumed		
Current liabilities		224
Long-term debt		406
Other non-current liabilities		39
Future income taxes		774
Total Purchase Price and Liabilities Assumed	$	3,797
Fair Value of Assets Acquired:		
Current assets (including cash acquired)	$	425
Property, plant and equipment, net		2,890
Other non-current assets		9
Goodwill (allocated to Upstream)		473
Total Fair Value of Assets Acquired	$	3,797

NOTE 3. 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. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East and Greenland.

Market Optimization is conducted by the Midstream & Marketing division. The Marketing groups primary responsibility is the sale of the Company s proprietary production. The 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 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 instrument relates.

Market Optimization purchases substantially all of the Company s North American Upstream production for sale to third party customers. 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 4.

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Results of Continuing Operations *(for the years ended December 31)*

	Upstream			Market Optimization		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ 10,465**	$ 7,256	$ 5,797	**$ 4,267**	$ 3,200	$ 2,722
Expenses						
Production and mineral taxes	**453**	311	164			
Transportation and selling	**525**	472	429	**13**	18	47
Operating	**1,351**	1,026	872	**85**	74	93
Purchased product				**4,159**	3,092	2,572
Depreciation, depletion and amortization	**2,688**	2,271	1,900	**8**	47	26
Segment Income (Loss)	**$ 5,448**	$ 3,176	$ 2,432	**$ 2**	$ (31)	$ (16)

	Corporate			Consolidated		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ (466)**	$ (197)	$ 2	**$ 14,266**	$ 10,259	$ 8,521
Expenses						
Production and mineral taxes				**453**	311	164
Transportation and selling				**538**	490	476
Operating	**2**	(1)		**1,438**	1,099	965
Purchased product				**4,159**	3,092	2,572
Depreciation, depletion and amortization	**73**	61	41	**2,769**	2,379	1,967
Segment Income (Loss)	**$ (541)**	$ (257)	$ (39)	**4,909**	2,888	2,377
Administrative				**268**	197	173
Interest, net				**524**	398	284
Accretion of asset retirement obligation				**37**	22	17
Foreign exchange (gain) loss, net				**(24)**	(412)	(603)
Stock-based compensation - options				**15**	17	18
(Gain) on divestitures					(59)	(1)
				820	163	(112)
Net Earnings Before Income Tax				**4,089**	2,725	2,489
Income tax expense				**1,260**	632	351
Net Earnings From Continuing Operations				**$ 2,829**	$ 2,093	$ 2,138

Upstream

	Canada			United States		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ 7,005**	$ 5,083	$ 4,474	**$ 3,177**	$ 1,941	$ 1,143

Expenses											
Production and mineral taxes		**104**		87		56		**349**		224		108
Transportation and selling		**343**		352		343		**182**		120		86
Operating		**826**		685		642		**212**		119		60
Depreciation, depletion and amortization		**1,927**		1,751		1,511		**682**		475		293
Segment Income (Loss)	**$**	**3,805**	$	2,208	$	1,922	**$**	**1,752**	$	1,003	$	596

		Other						Total Upstream				
		2005		**2004**		**2003**		**2005**		**2004**		**2003**
Revenues, Net of Royalties	**$**	**283**	$	232	$	180	**$**	**10,465**	$	7,256	$	5,797
Expenses												
Production and mineral taxes								**453**		311		164
Transportation and selling								**525**		472		429
Operating		**313**		222		170		**1,351**		1,026		872
Depreciation, depletion and amortization		**79**		45		96		**2,688**		2,271		1,900
Segment Income (Loss)	**$**	**(109)**	$	(35)	$	(86)	**$**	**5,448**	$	3,176	$	2,432

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Upstream Geographic and Product Information (Continuing Operations) *(for the years ended December 31)*

	Produced Gas								
	Canada			**United States**			**Total**		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ 5,486**	$ 3,928	$ 3,396	**$ 2,932**	$ 1,776	$ 1,051	**$ 8,418**	$ 5,704	$ 4,447
Expenses									
Production and mineral taxes	**76**	65	52	**325**	205	101	**401**	270	153
Transportation and selling	**283**	296	274	**182**	120	86	**465**	416	360
Operating	**521**	400	342	**212**	119	60	**733**	519	402
Operating Cash Flow	**$ 4,606**	$ 3,167	$ 2,728	**$ 2,213**	$ 1,332	$ 804	**$ 6,819**	$ 4,499	$ 3,532

	Oil and NGLs								
	Canada			**United States**			**Total**		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ 1,519**	$ 1,155	$ 1,078	**$ 245**	$ 165	$ 92	**$ 1,764**	$ 1,320	$ 1,170
Expenses									
Production and mineral taxes	**28**	22	4	**24**	19	7	**52**	41	11
Transportation and selling	**60**	56	69				**60**	56	69
Operating	**305**	285	300				**305**	285	300
Operating Cash Flow	**$ 1,126**	$ 792	$ 705	**$ 221**	$ 146	$ 85	**$ 1,347**	$ 938	$ 790

	Other			**Total Upstream**		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ 283**	$ 232	$ 180	**$ 10,465**	$ 7,256	$ 5,797
Expenses						
Production and mineral taxes				**453**	311	164
Transportation and selling				**525**	472	429
Operating	**313**	222	170	**1,351**	1,026	872
Operating Cash Flow	**$ (30)**	$ 10	$ 10	**$ 8,136**	$ 5,447	$ 4,332

Capital Expenditures (Continuing Operations)

For the years ended December 31	2005	2004	2003
Upstream Core Capital			
Canada	**$ 4,150**	$ 3,015	$ 2,937
United States	**1,982**	1,249	830
Other Countries	**70**	79	78
	6,202	4,343	3,845
Upstream Acquisition Capital			
Canada	**30**	64	261
United States	**418**	300	138
	448	364	399
Market Optimization	**197**	10	5
Corporate	**78**	46	107
Total	**$ 6,925**	$ 4,763	$ 4,356

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 held the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operated the properties, received all the revenue and paid all of the expenses associated with the properties. EnCana determined that the relationship with Brown Ranger LLC represented an interest in a variable interest entity (VIE) and that EnCana was the primary beneficiary of the VIE. EnCana consolidated Brown Ranger LLC from the date of acquisition to the date the properties were transferred to EnCana in 2005.

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Additions to Goodwill

There was no addition to goodwill during 2005 (2004 $473 million as a result of the business combination with Tom Brown, Inc. (see Note 2)). All goodwill included in continuing operations relates to the Upstream segment.

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment		Total Assets	
As at December 31		**2005**	**2004**	**2005**	**2004**
Upstream		**$ 24,247**	$ 22,097	**$ 28,858**	$ 26,118
Market Optimization		**371**	167	**597**	414
Corporate		**263**	239	**1,530**	1,385
Assets of Discontinued Operations	*(Note 4)*			**3,163**	3,296
Total		**$ 24,881**	$ 22,503	**$ 34,148**	$ 31,213

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,784 million (2004 - $1,747 million; 2003 - $1,484 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, 2005, the Company had one customer (2004 one) 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 $2,056 million (2004 - $1,709 million).

NOTE 4. DISCONTINUED OPERATIONS

2005

Midstream

On December 13, 2005 EnCana completed the sale of its Midstream natural gas liquids processing operations for total proceeds of $625 million (C$720 million). The natural gas liquids processing operations included various interests in a number of processing and related facilities as well as a marketing entity. A gain on sale of approximately $370 million, after-tax, was recorded.

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana s natural gas storage operations include the 100 percent interest in the AECO storage facility as well as facilities in the United States.

2004

Upstream

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.

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At December 31, 2004, EnCana decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. On September 13, 2005, EnCana announced it had reached an agreement in principle to sell all its interest in its Ecuador properties for $1.42 billion, which is approximately equivalent to the asset s net book value at July 1, 2005, the referenced effective date of the transaction.

Included in net earnings for the year is a provision of $234 million which has been recorded against the net book value to recognize management s best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments, as required under Canadian generally accepted accounting principles.

EnCana s Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in relation to 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

Upstream

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.

Midstream

In January 2003, EnCana closed the previously announced sales of its crude oil pipeline business resulting in an after-tax gain on sale of $169 million.

CONSOLIDATED STATEMENT OF EARNINGS

The following tables present the effect of the discontinued operations in the Consolidated Statement of Earnings:

Upstream Ecuador

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ 965**	$ 471	$ 412
Expenses			
Production and mineral taxes	**131**	61	25
Transportation and selling	**58**	60	45
Operating	**138**	125	83
Depreciation, depletion and amortization	**234**	263	159
Interest, net	**(2)**	(3)	4
Accretion of asset retirement obligation	**1**	1	1
Foreign exchange (gain) loss	**(4)**	5	2
	556	512	319
Net Earnings (Loss) Before Income Tax	**409**	(41)	93
Income tax expense (recovery)	**278**	(8)	61
Net Earnings (Loss) From Discontinued Operations	**$ 131**	$ (33)	$ 32

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Upstream United Kingdom

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$**	$ 153	$ 118
Expenses			
Transportation and selling		36	16
Operating		36	18
Depreciation, depletion and amortization		118	74
Interest, net		(9)	
Accretion of asset retirement obligation		3	1
Foreign exchange (gain), net	**(40)**	(2)	(5)
(Gain) loss on discontinuance		(1,365)	1
	(40)	(1,183)	105
Net Earnings (Loss) Before Income Tax	**(40)**	1,336	13
Income tax expense (recovery)	**5**	(2)	20
Net Earnings (Loss) From Discontinued Operations	**$ 35**	$ 1,338	$ (7)

Upstream Syncrude

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$**	$ (1)	$ 87
Expenses			
Transportation and selling			2
Operating			46
Depreciation, depletion and amortization			7
Loss on discontinuance		2	
		2	55
Net (Loss) Earnings Before Income Tax		(3)	32
Income tax expense			8
Net (Loss) Earnings From Discontinued Operations	**$**	$ (3)	$ 24

Midstream

For the years ended December 31	2005	2004	2003
Revenues	**$ 1,570**	$ 1,551	$ 1,165
Expenses			
Transportation and selling	**9**	9	8

Operating	**301**	251	231
Purchased product	**1,100**	1,184	883
Depreciation, depletion and amortization	**28**	23	22
Administrative	**30**		
Interest, net	**(2)**	(1)	(1)
Foreign exchange (gain) loss, net	**(2)**	(5)	5
(Gain) on discontinuance	**(364)**	(54)	(220)
	1,100	1,407	928
Net Earnings Before Income Tax	**470**	144	237
Income tax expense	**39**	26	64
Net Earnings From Discontinued Operations	**$ 431**	$ 118	$ 173

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Consolidated Total

For the years ended December 31	2005	2004	2003
Revenues, Net of Royalties	**$ 2,535**	$ 2,174	$ 1,782
Expenses			
Production and mineral taxes	**131**	61	25
Transportation and selling	**67**	105	71
Operating	**439**	412	378
Purchased product	**1,100**	1,184	883
Depreciation, depletion and amortization	**262**	404	262
Administrative	**30**		
Interest, net	**(4)**	(13)	3
Accretion of asset retirement obligation	**1**	4	2
Foreign exchange (gain) loss, net	**(46)**	(2)	2
(Gain) on discontinuance	**(364)**	(1,417)	(219)
	1,616	738	1,407
Net Earnings Before Income Tax	**919**	1,436	375
Income tax expense	**322**	16	153
Net Earnings From Discontinued Operations	**$ 597**	$ 1,420	$ 222
Net Earnings from Discontinued Operations per Common Share			
Basic	**$ 0.69**	$ 1.55	$ 0.24
Diluted	**$ 0.67**	$ 1.51	$ 0.23

CONSOLIDATED BALANCE SHEET

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

As at December 31	2005	2004
Assets		
Cash and cash equivalents	**$ 208**	$ 23
Accounts receivable and accrued revenues	**408**	456
Risk management	**21**	22
Inventories	**413**	470
	1,050	971
Property, plant and equipment, net	**1,686**	1,932
Investments and other assets	**360**	328
Goodwill	**67**	65
	$ 3,163	$ 3,296

Liabilities		
Accounts payable and accrued liabilities	**$ 167**	$ 233
Income tax payable	**230**	103
Risk management	**41**	89
	438	425
Asset retirement obligation	**21**	22
Future income taxes	**246**	202
	705	649
Net Assets of Discontinued Operations	**$ 2,458**	$ 2,647

Included in Midstream is $117 million (2004 - $102 million; 2003 - $97 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

The prices used in the ceiling test evaluation of the Company s crude oil reserves in Ecuador at December 31, 2005 were as follows:

	2006	**2007**	**2008**	**2009**	**2010**	**% increase to 2017**
Crude Oil *($/barrel)*	$ 42.70	$ 42.44	$ 40.92	$ 28.26	$ 28.13	13%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Acquisitions / Divestitures

On December 22, 2004 EnCana completed the divestiture 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 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, 2005	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Pipeline Transportation	$ 89	$ 91	$ 93	$ 95	$ 97	$ 827	$ 1,292

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. In its 2004 filings with Securities regulatory authorities, Occidental Petroleum Corporation indicated 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 filings, 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. The subsidiary of Occidental Petroleum Corporation has delivered, to the Government of Ecuador, its written defense to the allegations. Upon review, the Government of Ecuador may decide whether there are grounds for termination of the Participation Contract.

In addition to the above, the Company is proceeding with its arbitration related to value-added tax (VAT) owed to subsidiaries of EnCana ($169 million at December 31, 2005; 2004 - $139 million). EnCana is also in discussions related to certain income tax matters related to the deductibility of interest expense and foreign currency losses in Ecuador.

NOTE 5. **DIVESTITURES (ACQUISITIONS)**

For the years ended December 31	2005	2004	2003
Upstream	**$ 2,521**	$ 1,430	$ 210
Market Optimization		26	
Other	**2**	44	
	$ 2,523	$ 1,500	$ 210

Proceeds received on the sale of assets and investments in 2005 were $2,523 million (2004 - $1,500 million) as described below:

Upstream

In 2005, EnCana completed the disposition of various mature conventional oil and natural gas assets for proceeds of $471 million (2004 - $1,430 million; 2003 - $301 million).

In May 2005, EnCana completed the sale of its Gulf of Mexico assets for approximately $2.1 billion

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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resulting in net proceeds of approximately $1.5 billion after deducting $578 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

On July 18, 2003 EnCana acquired the common shares of Savannah Energy Inc.(Savannah) for net cash consideration of $91 million. Savannah s operations are located in Texas, U.S.A.

Market Optimization

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.

Other

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.

NOTE 6. INTEREST, NET

For the years ended December 31		**2005**		**2004**		**2003**
Interest Expense Long-Term Debt	**$**	**417**	$	385	$	281
Early Retirement of Long-Term Debt		**121**		(16)		
Interest Expense Other		**18**		42		20
Interest Income		**(32)**		(13)		(17)
	$	**524**	$	398	$	284

During 2005, EnCana redeemed a number of unsecured notes with a principal of C$1,150 million. The $121 million before tax ($79 million after-tax) charge is due to the early retirement of these medium term notes (see Note 12).

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 detailed below (see Note 12). The net effect of these transactions reduced interest costs in 2005 by $16 million (2004 - $22 million; 2003 - $23 million).

Swap Positions as at December 31, 2005:

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
7.50% due August 25, 2006 C$100 million	US$ 73 million	C$ Fixed	US$ Fixed*	4.14%
5.80% due June 2, 2008	US$ 71 million	C$ Fixed	US$ Fixed*	4.80%
C$225 million	C$ 125 million	C$ Fixed	C$ Floating	3 month Bankers Acceptance less 5 basis points

* These instruments have been subject to multiple swap transactions.

NOTE 7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31	2005	2004	2003
Unrealized Foreign Exchange Gain on Translation of U.S. Dollar Debt Issued in Canada	**$ (113)**	$ (285)	$ (545)
Other Foreign Exchange Loss (Gain)	**89**	(127)	(58)
	$ (24)	$ (412)	$ (603)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 8. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31	2005	2004	2003
Current			
Canada	**$ 493**	$ 586	$ (142)
United States	**719**	(12)	39
Other	**(8)**	(15)	(16)
Total Current Tax	**1,204**	559	(119)
Future	**56**	182	829
Future Tax Rate Reductions		(109)	(359)
Total Future Tax	**56**	73	470
	$ 1,260	$ 632	$ 351

Included in cash tax for 2005 is $578 million related to the sale of the Gulf of Mexico assets.

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

For the years ended December 31	2005	2004	2003
Net Earnings Before Income Tax	**$ 4,089**	$ 2,725	$ 2,489
Canadian Statutory Rate	**37.9%**	39.1%	41.0%
Expected Income Tax	**1,550**	1,066	1,020
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**207**	192	231
Canadian resource allowance	**(202)**	(246)	(258)
Canadian resource allowance on unrealized risk management losses		(10)	
Statutory and other rate differences	**(235)**	(50)	(44)
Effect of tax rate changes		(109)	(359)
Non-taxable capital gains	**(24)**	(91)	(119)
Previously unrecognized capital losses		17	(119)
Tax basis retained on dispositions	**(68)**	(169)	
Large corporations tax	**25**	24	27
Other	**7**	8	(28)
	$ 1,260	$ 632	$ 351

Effective Tax Rate	**30.8%**	23.2%	14.1%

The net future income tax liability is comprised of:

As at December 31	**2005**	**2004**
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,461**	$ 4,390
Timing of Partnership items	**1,226**	975
Future Tax Assets		
Net operating losses carried forward	**(47)**	(103)
Other	**(351)**	(180)
Net Future Income Tax Liability	**$ 5,289**	$ 5,082

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

The approximate amounts of tax pools available are as follows:

As at December 31	2005	2004
Canada	**$ 8,575**	$ 7,034
United States	**2,978**	2,760
	$ 11,553	$ 9,794

Included in the above tax pools are $133 million (2004 - $275 million) related to non-capital or net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2008 and 2023.

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 Corporation.

NOTE 9. INVENTORIES

As at December 31	2005	2004
Product		
Upstream	**$ 70**	$ 14
Market Optimization	**31**	42
Parts and Supplies	**2**	2
	$ 103	$ 58

NOTE 10. PROPERTY, PLANT AND EQUIPMENT, NET

		2005			2004	
As at December 31	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream						
Canada	**$ 29,199**	**$ (12,144)**	**$ 17,055**	$ 24,390	$ (9,775)	$ 14,615
United States	**8,707**	**(1,763)**	**6,944**	8,360	(1,056)	7,304
Other Countries	**470**	**(222)**	**248**	425	(247)	178
Total Upstream	**38,376**	**(14,129)**	**24,247**	33,175	(11,078)	22,097

Market Optimization	**419**	**(48)**	**371**	208	(41)	167
Corporate	**544**	**(281)**	**263**	455	(216)	239
	$ 39,339	**$ (14,458)**	**$ 24,881**	$ 33,838	$ (11,335)	$ 22,503

* Depreciation, depletion and amortization

Included in property, plant and equipment are asset retirement costs, net of amortization, of $498 million (2004 - $393 million). Administrative costs have not been capitalized as part of the capital expenditures.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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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	2005	2004	2003
Canada	**$ 1,689**	$ 1,444	$ 1,444
United States	**870**	1,119	499
Other Countries	**248**	177	112
	$ 2,807	$ 2,740	$ 2,055

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. For the year ended December 31, 2005, the Company completed its impairment review of pre-production cost centres and determined that $7 million of costs should be charged to the Consolidated Statement of Earnings (2004 - $23 million; 2003 - $85 million).

The prices used in the ceiling test evaluation of the Company s crude oil and natural gas reserves at December 31, 2005 were:

	2006	2007	2008	2009	2010	% increase to 2017
Natural Gas *($/Mcf)*						
Canada	$ 9.42	$ 8.42	$ 7.35	$ 4.87	$ 4.84	17%
United States	$ 9.92	$ 8.59	$ 7.51	$ 5.30	$ 5.29	12%
Crude Oil *($/barrel)*						
Canada	$ 34.50	$ 33.11	$ 31.61	$ 21.75	$ 21.57	8%
Natural Gas Liquids *($/barrel)*						
Canada	$ 55.92	$ 56.21	$ 53.25	$ 36.11	$ 36.14	17%
United States	$ 53.92	$ 53.36	$ 52.04	$ 34.68	$ 34.24	15%

NOTE 11. INVESTMENTS AND OTHER ASSETS

As at December 31	2005	2004
Equity Investments	**$ 7**	$ 8

Marketing Contracts	**10**	12
Deferred Financing Costs	**59**	61
Deferred Pension Plan and Savings Plan	**60**	64
Prepaid Capital	**334**	160
Other	**26**	29
	$ 496	$ 334

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PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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NOTE 12. LONG-TERM DEBT

As at December 31	Note	2005	2004
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*B*	**$ 1,425**	$ 1,515
Unsecured notes	*C*	**793**	1,309
		2,218	2,824
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	*D*		399
Unsecured notes and debentures	*E*	**4,494**	4,641
		4,494	5,040
Increase in Value of Debt Acquired	*F*	**64**	66
Current Portion of Long-Term Debt	*G*	**(73)**	(188)
		$ 6,703	$ 7,742

A) Overview

Revolving credit and term loan borrowings

At December 31, 2005, EnCana Corporation had in place a revolving credit facility for $4.5 billion Canadian dollars or its equivalent amount in U.S. dollars ($3.9 billion). The facility is fully revolving for a period of five years from the date of the agreement, October 2005. The facility is extendible from time to time, but not more than once per year, for a period not longer than 5 years from the extension date, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders rates for Canadian prime, U.S. base rate, Bankers Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2005, one of EnCana s subsidiaries had in place a credit facility totaling $600 million. The facility is guaranteed by EnCana Corporation and fully revolving for five years from the date of the Agreement, December, 2005. The facility is extendible from time to time, but not more than once per year, for a period not longer than 5 years from the extension date, 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 $1,425 million (2004 - $1,559 million) maturing at various dates with a weighted average interest rate of 3.52% (2004 2.83%). There were no LIBOR loans outstanding at December 31, 2005 (2004 - $355 million with a weighted average interest rate of 2.98%). 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 2005 relating to revolving credit and term loan agreements were approximately $4 million (2004 - $5 million; 2003 - $3 million).

Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company s current C$1 billion medium term note program was renewed in 2005 with C$500 million ($429 million) unutilized at December 31, 2005. The current shelf prospectus expires in 2007. The notes issued under this program 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.

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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, 2005, $2 billion of the shelf prospectus, which expires in 2006, 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, 2005, $1 billion of the shelf prospectus, which expires in 2006, remains unutilized.

B) Canadian revolving credit and term loan borrowings

	C$ Principal Amount	2005	2004
Bankers Acceptances	**$ 430**	**$ 369**	$ 511
Commercial Paper	**1,231**	**1,056**	1,004
	$ 1,661	**$ 1,425**	$ 1,515

C) Canadian unsecured notes

	C$ Principal Amount	2005	2004
5.95% due October 1, 2007	**$**	**$**	$ 166
5.30% due December 3, 2007	**300**	**257**	248
5.95% due June 2, 2008			83
5.80% due June 2, 2008	**125**	**107**	104
5.80% due June 19, 2008			83
3.60% due September 15, 2008	**500**	**429**	
6.10% due June 1, 2009			125
7.15% due December 17, 2009			125
8.50% due March 15, 2011			42
7.10% due October 11, 2011			166
7.30% due September 2, 2014			125
6.20% due June 23, 2028			42
	$ 925	**$ 793**	$ 1,309

During the third quarter of 2005, EnCana redeemed a number of unsecured medium term notes with a total principal of C$1,150 (Note 6).

D) *U.S. revolving credit and term loan borrowings*

	2005	2004
Commercial Paper	$	$ 44
LIBOR Loan		355
	$	$ 399

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

E) *U.S. unsecured notes and debentures*

	C$ Amount	2005	2004
Floating Rate			
8.75% due November 9, 2005	$	$	$ 73
Fixed Rate			
8.75% due November 9, 2005			73
7.50% due August 25, 2006	**85***	**73**	73
5.80% due June 2, 2008	**83***	**71**	71
4.60% due August 15, 2009		**250**	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**	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**	750
		$ 4,494	$ 4,641

* 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.

F) *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 21 years.

G) *Current portion of long-term debt*

	2005	2004
6.20% Medium Term Note due June 23, 2028	**$**	$ 42
8.75% Unsecured Note due November 9, 2005		146
7.50% Medium Term Note due August 25, 2006	**73**	
	$ 73	$ 188

H) Mandatory debt payments

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2006	$	$ 73	**$ 73**
2007	300		**257**
2008	625	71	**607**
2009		250	**250**
2010		200	**200**
Thereafter	1,661	3,900	**5,325**
Total	$ 2,586	$ 4,494	**$ 6,712**

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PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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The amount due in 2006 excludes Bankers Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

NOTE 13. 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		2005		2004
Asset Retirement Obligation, Beginning of Year	**$**	**611**	$	383
Liabilities Incurred		**77**		98
Liabilities Settled		**(42)**		(16)
Liabilities Disposed		**(23)**		(35)
Change in Estimated Future Cash Flows		**135**		124
Accretion Expense		**37**		22
Other		**21**		35
Asset Retirement Obligation, End of Year	**$**	**816**	$	611

The total undiscounted amount of estimated cash flows required to settle the obligation is $4,944 million (2004 - $3,695 million), which has been discounted using a weighted average credit-adjusted risk free rate of 5.74 percent (2004 5.94 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 14. 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	2005 Number (millions)		2005 Amount	2004 Number (millions)		2004 Amount
Common Shares Outstanding, Beginning of Year	**900.6**	**$**	**5,299**	921.2	$	5,305
Common Shares Issued under Option Plans	**15.0**		**294**	19.4		281
Common Shares Repurchased	**(60.7)**		**(462)**	(40.0)		(287)
Common Shares Outstanding, End of Year	**854.9**	**$**	**5,131**	900.6	$	5,299

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

Normal Course Issuer Bid

In 2005, the Company purchased 60,757,198 Common Shares for total consideration of $2,114 million. Of the amount paid, $462 million was charged to Share capital, $10 million was charged to Paid in surplus and $1,642 million was charged to Retained earnings. Included in the above are 5.5 million Common Shares which have been purchased by an EnCana Employee Benefit Plan Trust and are held for issuance upon vesting of units under EnCana s Performance Share Unit Plan (see Note 15).

EnCana has received regulatory approval each year under Canadian securities laws to purchase

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Common Shares under four consecutive Normal Course Issuer Bids (Bids) which commenced in October 2002 and may continue up to October 30, 2006. EnCana is entitled to purchase, for cancellation, up to approximately 85.6 million Common Shares under the current Bid. During January 2006, EnCana purchased approximately 6.8 million Common Shares under the Bid for total consideration of $314 million. Under the prior Bid, which ran from October 29, 2004 until October 28, 2005, EnCana purchased approximately 84.2 million Common Shares.

Stock Options

EnCana has stock-based compensation plans that allow employees and directors to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to ten years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right (TSAR) attached to them (see Note 15).

In conjunction with the business combination transaction with Alberta Energy Company Ltd. (AEC) in 2002, 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 EnCana Common Shares. 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 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.

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 and on October 25, 2005 the Corporation terminated the plan.

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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	2005 Stock Options (millions)	2005 Weighted Average Exercise Price (C$)	2004 Stock Options (millions)	2004 Weighted Average Exercise Price (C$)	2003 Stock Options (millions)	2003 Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	**36.2**	**23.15**	57.6	21.57	59.2	19.87
Granted under EnCana Plan					12.6	23.99
Granted under Directors Plan					0.2	23.94
Exercised	**(14.9)**	**22.90**	(19.4)	18.32	(11.0)	14.56
Forfeited	**(0.6)**	**21.71**	(2.0)	23.75	(3.4)	20.59
Outstanding, End of Year	**20.7**	**23.36**	36.2	23.15	57.6	21.57
Exercisable, End of Year	**16.8**	**23.21**	21.6	22.55	31.2	19.46

As at December 31, 2005 Range of Exercise Price (C$)	Outstanding Options Number of Options Outstanding (millions)	Outstanding Options Weighted Average Remaining Contractual Life (years)	Outstanding Options Weighted Average Exercise Price (C$)	Exercisable Options Number of Options Outstanding (millions)	Exercisable Options Weighted Average Exercise Price (C$)
10.50 to 22.99	1.7	2.3	15.74	1.7	15.60
23.00 to 23.49	1.3	0.7	23.17	1.1	23.16
23.50 to 23.99	6.9	2.3	23.89	3.6	23.88
24.00 to 24.49	10.2	1.2	24.18	10.1	24.18
24.50 to 25.99	0.6	2.6	25.23	0.3	25.21
	20.7	1.7	23.36	16.8	23.21

At December 31, 2005, there were 29.3 million common shares reserved for issuance under stock option plans (2004 16.0 million; 2003 15.6 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. Stock options granted subsequent to December 31, 2003 have an associated TSAR attached. 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 2005 would have been unchanged (2004 - $3,476 million; $3.77 per common share basic; $3.71 per common share diluted).

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

For the year ended December 31		2003
Weighted Average Fair Value of Options Granted *(C$)*	$	6.11
Risk-Free Interest Rate		3.87%
Expected Lives *(years)*		3.00
Expected Volatility		0.33
Annual Dividend per Share *(C$/common share)*	$	0.20

At December 31, 2005 the balance in Paid in surplus relates to Stock Based Compensation programs.

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NOTE 15. COMPENSATION PLANS

Where applicable, the amounts below have been restated to reflect the effect of the common share split approved in April 2005.

A) Pensions and Post-Employment Benefits

The most recent actuarial valuation completed for the Company s pension plans is dated December 31, 2004. The next required valuation will be as at December 31, 2007.

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	**2005**	**2004**	**2003**
Total Expense for Defined Contribution Plans	**$ 22**	$ 19	$ 12

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

	Pension Benefits		**OPEB**	
As at December 31	**2005**	**2004**	**2005**	**2004**
Accrued Benefit Obligation, Beginning of Year	**$ 246**	$ 214	**$ 19**	$ 14
Beginning of year adjustment		(1)		
Amendments			**13**	
Current service cost	**6**	5	**5**	1
Interest cost	**14**	13	**2**	1
Benefits paid	**(12)**	(10)	**(1)**	
Actuarial loss	**29**	8		1
Contributions	**1**	1		
Foreign exchange	**10**	16	**1**	2
Accrued Benefit Obligation, End of Year	**$ 294**	$ 246	**$ 39**	$ 19

The amendments made January 1, 2005 relate to obligations for OPEB related to the acquisition of TBI and changes made to one of the Company s Plans which increased the Company s post-employment benefit obligation.

	Pension Benefits		OPEB	
As at December 31	**2005**	**2004**	**2005**	**2004**
Fair Value of Plan Assets, Beginning of Year	**$ 247**	$ 203	**$**	$
Actual return on plan assets	**29**	19		
Employer contributions	**9**	17		
Employees contributions	**1**	1		
Benefits paid	**(12)**	(10)		
Foreign exchange	**10**	17		
Fair Value of Plan Assets, End of Year	**$ 284**	$ 247	**$**	$

	Pension Benefits		OPEB	
As at December 31	**2005**	**2004**	**2005**	**2004**
Funded Status Plan Assets (less) than Benefit Obligation	**$ (10)**	$ 1	**$ (39)**	$ (19)
Amounts Not Recognized:				
Unamortized net actuarial loss	**64**	54	**4**	4
Unamortized past service cost	**9**	10	**1**	2
Net transitional asset	**(8)**	(11)	**14**	2
Accrued Benefit Asset (Liability)	**$ 55**	$ 54	**$ (20)**	$ (11)

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	Pension Benefits		OPEB	
As at December 31	**2005**	**2004**	**2005**	**2004**
Prepaid Benefit Cost	**$ 55**	$ 54	**$**	$
Accrued Benefit Cost			**(20)**	(11)
Net Amount Recognized	**$ 55**	$ 54	**$ (20)**	$ (11)

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:

	Pension Benefits		OPEB	
As at December 31	**2005**	**2004**	**2005**	**2004**
Discount Rate	**5.00%**	5.75%	**5.25%**	5.75%
Rate of Compensation Increase	**4.50%**	4.60%	**5.65%**	5.65%

The weighted average assumptions used to determine periodic expense are as follows:

	Pension Benefits		OPEB	
For the years ended December 31	**2005**	**2004**	**2005**	**2004**
Discount Rate	**5.75%**	6.00%	**5.75%**	6.00%
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	**4.60%**	4.75%	**5.65%**	5.75%

The periodic expense for benefits is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Current Service Cost	**$ 6**	$ 5	$ 5	**$ 5**	$ 1	$ 1
Interest Cost	**14**	13	11	**2**	1	1
Actual Return on Plan Assets	**(29)**	(19)	(16)			
	29	8	12		1	1

Actuarial Loss on Accrued Benefit Obligation						
Plan Amendment						2
Difference Between Actual and:						
Expected return on plan assets	**15**	7	7			
Recognized actuarial loss	**(24)**	(4)	(8)		(1)	(1)
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	1			(2)
Amortization of Transitional Obligation	**(3)**	(2)	(2)	**1**		
Expense for Defined Contribution Plan	**22**	19	12			
Net Benefit Plan Expense	**$ 32**	$ 29	$ 22	**$ 8**	$ 2	$ 2

The average remaining service period of the active employees covered by the defined benefit pension plan is seven years. The average remaining service period of the active employees covered by the other retirement benefits plan is 12 years.

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Assumed health care cost trend rates are as follows:

As at December 31	**2005**	**2004**
Health Care Cost Trend Rate for Next Year	**11.00%**	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**	2015

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	$ 1	$ (1)
Effect on Post Retirement Benefit Obligation	$ 4	$ (3)

The Company s pension plan asset allocations are as follows:

Asset Category	Target Allocation% Normal	Target Allocation% Range	% of Plan Assets at December 31 2005	% of Plan Assets at December 31 2004	Expected Long-Term Rate of Return
Domestic Equity	35	25-45	**41**	38	
Foreign Equity	30	20-40	**27**	28	
Bonds	30	20-40	**25**	27	
Real Estate and Other	5	0-20	**7**	7	
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 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.

Management expects to contribute $10 million to the plans in 2006. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2005 (2004 - $1 million; 2003 - $1 million).

Estimated future payments for pension and other benefits are as follows:

	Pension Benefits	OPEB
2006	$ 13	$ 1
2007	14	1
2008	15	2
2009	16	2
2010	16	2
2011 2015	96	23
Total	$ 170	$ 31

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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 EnCana 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	2005 Outstanding SAR s	2005 Weighted Average Exercise Price	2004 Outstanding SAR s	2004 Weighted Average Exercise Price
Canadian Dollar Denominated ***(C$)***				
Outstanding, Beginning of Year	**930,510**	**18.31**	2,350,140	17.94
Exercised	**(682,241)**	**16.55**	(1,397,550)	17.74
Forfeited	**(1,530)**	**23.14**	(22,080)	14.63
Outstanding, End of Year	**246,739**	**23.13**	930,510	18.31
Exercisable, End of Year	**246,739**	**23.13**	930,510	18.31
U.S. Dollar Denominated ***(US$)***				
Outstanding, Beginning of Year	**771,860**	**14.40**	1,506,834	14.49
Exercised	**(452,349)**	**14.45**	(731,294)	14.60
Forfeited			(3,680)	12.65
Outstanding, End of Year	**319,511**	**14.33**	771,860	14.40
Exercisable, End of Year	**319,511**	**14.33**	771,860	14.40

As at December 31, 2005 Range of Exercise Price	SAR s Outstanding and Exercisable: Number of SAR s	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price
Canadian Dollar Denominated ***(C$)***			
20.00 to 29.99	246,739	0.19	23.13
	246,739	0.19	23.13
U.S. Dollar Denominated ***(US$)***			
10.00 to 19.99	319,511	0.32	14.33
	319,511	0.32	14.33

During the year, the Company recorded compensation costs of $17 million related to the outstanding SAR s (2004 - $17 million; 2003 - $12 million).

C) Tandem Share Appreciation Rights

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 14 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 EnCana s Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSAR s vest and expire under the same terms and conditions as the underlying option.

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The following tables summarize the information about the TSAR s:

	2005		2004	
As at December 31	**Outstanding TSAR s**	**Weighted Average Exercise Price**	**Outstanding TSAR s**	**Weighted Average Exercise Price**
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**1,735,000**	**27.77**		
Granted	**7,581,412**	**40.14**	2,160,900	27.66
Exercised - SARs	**(151,610)**	**27.51**		
Exercised - Options	**(104,735)**	**27.60**		
Forfeited	**(656,100)**	**34.44**	(425,900)	27.19
Outstanding, End of Year	**8,403,967**	**38.41**	1,735,000	27.77
Exercisable, End of Year	**229,705**	**28.00**		

	Outstanding TSAR s			Exercisable Options With TSAR s Attached	
As at December 31, 2005 Range of Exercise Price (C$)	**Number of TSAR s**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**	**Number of TSAR s**	**Weighted Average Exercise Price**
20.00 to 29.99	1,108,250	3.35	27.38	198,670	27.44
30.00 to 39.99	6,198,717	4.12	38.08	31,035	31.55
40.00 to 49.99	417,750	4.37	44.12		
50.00 to 59.99	606,150	4.74	54.83		
60.00 to 69.99	73,100	4.74	64.21		
	8,403,967	4.08	38.41	229,705	28.00

During the year, the Company recorded compensation costs of $60 million related to the outstanding TSAR s (2004 - $3 million).

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:

	2005		2004	
As at December 31	**Outstanding DSU s**	**Average Share Price**	**Outstanding DSU s**	**Average Share Price**
Canadian Dollar Denominated *(C$)*				
Outstanding, Beginning of Year	**750,612**	**24.81**	638,500	24.34
Granted, Directors	**80,765**	**43.75**	117,862	27.02
Units, in Lieu of Dividends	**5,184**	**52.34**	6,416	29.93
Exercised			(12,166)	24.34
Outstanding, End of Year	**836,561**	**26.81**	750,612	24.81
Exercisable, End of Year	**836,561**	**26.81**	587,910	26.28

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During the year, the Company recorded compensation costs of $16 million related to the outstanding DSU s (2004 - $10 million; 2003 - $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 and 2005 grant.

PSU s granted subsequent to 2003 are to be paid in common shares (2003 paid in cash).

The following table summarizes the information about the PSU s:

	2005		**2004**	
As at December 31	**Outstanding PSU s**	**Average Share Price**	**Outstanding PSU s**	**Average Share Price**
Canadian Dollar Denominated *(C$)*				
Outstanding, Beginning of Year	**3,294,206**	**26.71**	252,566	23.26
Granted	**1,734,089**	**38.13**	3,381,580	26.98
Forfeited	**(323,947)**	**30.48**	(339,940)	26.76
Outstanding, End of Year	**4,704,348**	**30.65**	3,294,206	26.71
U.S. Dollar Denominated *(US$)*				
Outstanding, Beginning of Year	**449,230**	**20.56**		
Granted	**390,171**	**30.92**	500,448	20.56
Forfeited	**(99,752)**	**26.50**	(51,218)	20.56
Outstanding, End of Year	**739,649**	**25.22**	449,230	20.56

During the year, the Company recorded compensation costs of $91 million related to the outstanding PSU s (2004 - $25 million; 2003 - $1 million).

At December 31, 2005, EnCana had approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU s.

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NOTE 16. 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.

The following table summarizes the realized and unrealized gains and losses on risk management activities:

	Realized Gain (Loss)		
As at December 31	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ (684)**	$ (662)	$ (318)
Operating Expenses and Other	**31**	28	34
Loss on Risk Management Continuing Operations	**(653)**	(634)	(284)
Loss on Risk Management Discontinued Operations	**(126)**	(410)	(20)
	$ (779)	$ (1,044)	$ (304)

	Unrealized Gain (Loss)		
As at December 31	**2005**	**2004**	**2003**
Revenues, Net of Royalties	**$ (466)**	$ (198)	$
Operating Expenses and Other	**(3)**	7	
Loss on Risk Management Continuing Operations	**(469)**	(191)	
Gain (Loss) on Risk Management Discontinued Operations	**50**	(70)	
	$ (419)	$ (261)	$

Amounts Recognized on Transition

Upon initial adoption of the current accounting policy for risk management instruments 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 transition amount). The transition amount 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.

At December 31, 2005, a net unrealized gain remains to be recognized over the next three years as follows:

	Unrealized Gain			
2006				
Three months ended March 31	$	4		
Three months ended June 30		7		
Three months ended September 30		7		
Three months ended December 31		6		
Total to be recognized in 2006			$	24
2007		15		
2008		1		
Total to be recognized in 2007 through to 2008				16
Total to be recognized			$	40

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Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts during 2005:

	Net Deferred Amounts Recognized on Transition	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts and Premiums Paid, Beginning of Year	$ (72)	$ (189)	$
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts entered into During 2005		(1,230)	(1,230)
Fair Value of Contracts In Place at Transition Expired During 2005	32		32
Fair Value of Contracts Realized During 2005		779	779
Fair Value of Contracts Outstanding	$ (40)	$ (640)	$ (419)
Unamortized Premiums Paid on Collars and Options		316	
Fair Value of Contracts and Premiums Paid, End of Year		$ (324)	
Amounts Allocated to Continuing Operations	$ (40)	$ (304)	$ (469)
Amounts Allocated to Discontinued Operations		(20)	50
	$ (40)	$ (324)	$ (419)

At December 31, 2005, the remaining net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

As at December 31	**2005**
Remaining Deferred Amount Recognized on Transition	
Accounts receivable and accrued revenues	**$ 1**
Investments and other assets	**1**
Accounts payable and accrued liabilities	**25**
Other liabilities	**17**
Net Deferred Gain Continuing Operations	**$ 40**

As at December 31	**2005**	**2004**
Risk Management		
Current asset	**$ 495**	$ 317
Long-term asset	**530**	87
Current liability	**1,227**	224

Long-term liability			**102**		192
Net Risk Management Liability	Continuing Operations		**(304)**		(12)
Net Risk Management Liability	Discontinued Operations		**(20)**		(67)
		$	**(324)**	$	(79)

A summary of all unrealized estimated fair value financial positions is as follows:

As at December 31		**Note**		**2005**		**2004**
Commodity Price Risk		*A*				
Natural gas			**$**	**(247)**	$	105
Crude oil				**(66)**		(143)
Power						2
Credit Derivatives		*C*		**(1)**		
Interest Rate Risk		*B*		**10**		24
Total Fair Value Positions	Continuing Operations			**(304)**		(12)
Total Fair Value Positions	Discontinued Operations			**(20)**		(67)
			$	**(324)**	$	(79)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

A) Commodity Price Risk

Natural Gas

At December 31, 2005 the Company s gas risk management activities from financial contracts had an unrealized loss of $(500) million and a fair market value position of $(267) million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	525	2006	5.65	US$/Mcf	$ (954)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(151)
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(146)
Other	81	2006	4.58	US$/Mcf	(126)
NYMEX Fixed Price	240	2007	7.76	US$/Mcf	(203)
Collars and Other Options					
Purchased NYMEX Put Options	2,602	2006	7.76	US$/Mcf	(73)
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	(5)
Basis Contracts					
Fixed NYMEX to AECO basis	799	2006	(0.69)	US$/Mcf	217
Fixed NYMEX to Rockies basis	324	2006	(0.58)	US$/Mcf	162
Fixed NYMEX to CIG basis	301	2006	(0.83)	US$/Mcf	133
Other	182	2006	(0.36)	US$/Mcf	52
Fixed Rockies to CIG basis	12	2007	(0.10)	US$/Mcf	
Fixed NYMEX to AECO basis	735	2007	(0.71)	US$/Mcf	101
Fixed NYMEX to Rockies basis	538	2007	(0.65)	US$/Mcf	232
Fixed NYMEX to CIG basis	390	2007	(0.76)	US$/Mcf	164
Fixed NYMEX to AECO basis	191	2008	(0.78)	US$/Mcf	12
Fixed NYMEX to Rockies basis	162	2008	(0.59)	US$/Mcf	52
Fixed NYMEX to CIG basis	40	2008-2009	(0.68)	US$/Mcf	23
Purchase Contracts					
Fixed Price Contract Waha Purchase	23	2006	5.32	US$/Mcf	33

		(477)
Gas Storage Optimization Financial Positions		(20)
Gas Marketing Financial Positions [1]		(3)
Total Unrealized Loss on Financial Contracts		(500)
Unamortized Premiums Paid on Options		233
Total Fair Value Positions	$	(267)
Total Fair Value Positions Continuing Operations		(247)
Total Fair Value Positions Discontinued Operations		(20)
Total Fair Value Positions	$	(267)

(1) The gas marketing activities are part of the daily ongoing operations of the Company s proprietary production management.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Crude Oil

As at December 31, 2005, the Company s oil risk management activities from all financial contracts had an unrealized loss of $(149) million and a fair market value position of $(66) million. The contracts were as follows:

	Notional Volumes (bbls/d)	Term	Average Price			Fair Market Value
Fixed WTI NYMEX Price	15,000	2006	34.56	US$/bbl	$	(153)
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75	US$/bbl		5
Purchased WTI NYMEX Put Options	57,000	2006	50.00	US$/bbl		(10)
Purchased WTI NYMEX Call Options	(13,700)	2006	61.24	US$/bbl		14
Purchased WTI NYMEX Put Options	43,000	2007	44.44	US$/bbl		(6)
						(150)
Other Financial Positions(1)						1
Total Unrealized Loss on Financial Contracts						(149)
Unamortized Premiums Paid on Options						83
Total Fair Value Positions					$	(66)
Total Fair Value Positions Continuing Operations					$	(66)
Total Fair Value Positions Discontinued Operations						
					$	(66)

(1) Other financial positions are part of the daily ongoing operations of the Company s proprietary production management.

B) 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 6.

The unrealized gains on the outstanding financial instruments were as follows:

As at December 31	Unrealized Gain 2005	2004
5.80% Medium Term Notes	**$ 7**	$ 11
7.50% Medium Term Notes	**3**	5
8.75% Debenture		8
	$ 10	$ 24

At December 31, 2005, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $10 million (2004 - $13 million).

C) 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

As at December 31	2005 Carrying Amount	2005 Fair Value	2004 Carrying Amount	2004 Fair Value
Financial Assets				
Cash and cash equivalents	**$ 105**	**$ 105**	$ 593	$ 593
Accounts receivable	**1,851**	**1,851**	1,566	1,566
Financial Liabilities				
Accounts payable, income taxes payable	**$ 3,133**	**$ 3,133**	$ 2,099	$ 2,099
Long-term debt	**6,776**	**7,180**	7,930	8,479

D) ***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 of Directors 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 and net settlements where appropriate. At December 31, 2005, EnCana has three counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

NOTE 17. SUPPLEMENTARY INFORMATION

A) Per Share Amounts

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

For the years ended December 31	2005	2004	2003
Weighted Average Common Shares Outstanding Basic	**868.3**	920.8	948.2
Effect of Stock Options and Other Dilutive Securities	**20.9**	15.2	11.2
Weighted Average Common Shares Outstanding Diluted	**889.2**	936.0	959.4

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

B) Net Change in Non-Cash Working Capital from Continuing Operations

For the years ended December 31	2005	2004	2003
Operating Activities			
Accounts receivable and accrued revenues	**$ (146)**	$ 825	$ (697)
Inventories	**(34)**	(22)	68
Accounts payable and accrued liabilities	**654**	585	(169)
Income taxes payable	**23**	177	54
	$ 497	$ 1,565	$ (744)
Investing Activities			
Accounts payable and accrued liabilities	**$ 330**	$ (29)	$ (112)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

C) Supplementary Cash Flow Information Continuing Operations

For the years ended December 31		**2005**		**2004**		**2003**
Interest Paid	**$**	**522**	$	402	$	285
Income Taxes Paid (Received)	**$**	**1,096**	$	136	$	(127)

NOTE 18. COMMITMENTS AND CONTINGENCIES

Commitments

As at December 31, 2005		**2006**		**2007**		**2008**		**2009**		**2010**		**Thereafter**		**Total**
Pipeline Transportation	$	339	$	305	$	255	$	208	$	196	$	850	**$**	**2,153**
Purchases of Goods and Services		230		220		137		97		41		33		**758**
Product Purchases		33		23		22		22		22		98		**220**
Operating Leases		48		46		40		33		32		132		**331**
Capital Commitments		92		24		5						38		**159**
Total	$	742	$	618	$	459	$	360	$	291	$	1,151	**$**	**3,621**
Product Sales	$	61	$	64	$	68	$	40	$	42	$	300	**$**	**575**
Discontinued Operations	$	(331)	$	27	$	40	$	59	$	102	$	793	**$**	**690**

In addition to the above, the Company has made commitments related to its risk management program (see Note 16).

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

California

As disclosed previously, 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 whereby 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.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

In all but one of the class actions in the United States District Court and in the Gallo action, decisions dealing with the issue of whether the scope of the Federal Energy Regulatory Commission s exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims are on appeal to the United States Court of Appeals for the Ninth Circuit.

Without admitting any liability in the lawsuits, in November 2005, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court, subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD is also a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle the New York class action lawsuit, subject to final documentation and approval by the New York District Court.

Based on the aforementioned settlements, during the fourth quarter of 2005 a total of $30 million was recorded, which amount has been included in Administrative costs in the Net Earnings from Discontinued Operations. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding 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 $816 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 19. 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 GAAP 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**	**2005**	**2004**	**2003**
Net Earnings Canadian GAAP		**$ 3,426**	$ 3,513	$ 2,360
Less:				
Net Earnings From Discontinued Operations Canadian GAAP		**597**	1,420	222
Net Earnings From Continuing Operations Canadian GAAP		**2,829**	2,093	2,138
Increase (Decrease) under U.S. GAAP:				
Revenues, net of royalties	*B*	**(217)**	345	(101)
Operating	*B*	**1**	(3)	
Depreciation, depletion and amortization	*A*	**55**	31	14
Interest, net	*B*	**(16)**	(41)	70
Stock-based compensation - options	*C*	**(12)**	(5)	(1)
Income tax expense	*E*	**59**	(105)	7
Net Earnings From Continuing Operations U.S. GAAP		**2,699**	2,315	2,127
Net Earnings From Discontinued Operations U.S. GAAP		**553**	1,418	156
Net Earnings Before Change in Accounting Policy U.S. GAAP		**3,252**	3,733	2,283
Cumulative Effect of Change in Accounting Policy, net of tax	*G*			66
Net Earnings U.S. GAAP		**$ 3,252**	$ 3,733	$ 2,349
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.41
Diluted		**$ 3.66**	$ 3.99	$ 2.38
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.48
Diluted		**$ 3.66**	$ 3.99	$ 2.45

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

CONSOLIDATED STATEMENT OF EARNINGS U.S. GAAP

For the years ended December 31	**Note**	**2005**	**2004**	**2003**
Revenues, Net of Royalties	*B*	**$ 14,049**	$ 10,604	$ 8,420
Expenses				
Production and mineral taxes		**453**	311	164
Transportation and selling		**538**	490	476
Operating	*B*	**1,437**	1,102	965
Purchased product		**4,159**	3,092	2,572
Depreciation, depletion and amortization	*A,G*	**2,714**	2,348	1,953
Administrative		**268**	197	173
Interest, net	*B*	**540**	439	214
Accretion of asset retirement obligation	*G*	**37**	22	17
Foreign exchange (gain) loss, net		**(24)**	(412)	(603)
Stock-based compensation - options	*C*	**27**	22	19
Gain on divestitures			(59)	(1)
Net Earnings Before Income Tax		**3,900**	3,052	2,471
Income tax expense	*E*	**1,201**	737	344
Net Earnings From Continuing Operations U.S. GAAP		**2,699**	2,315	2,127
Net Earnings From Discontinued Operations U.S. GAAP	*A,B*	**553**	1,418	156
Net Earnings Before Change in Accounting Policy U.S. GAAP		**3,252**	3,733	2,283
Cumulative Effect of Change in Accounting Policy, net of tax	*G*			66
Net Earnings - U.S. GAAP		**$ 3,252**	$ 3,733	$ 2,349
Net Earnings From Continuing Operations per Common Share U.S. GAAP				
Basic		**$ 3.11**	$ 2.51	$ 2.24
Diluted		**$ 3.04**	$ 2.47	$ 2.22
Net Earnings From Discontinued Operations per Common Share U.S. GAAP				
Basic		**$ 0.64**	$ 1.54	$ 0.17
Diluted		**$ 0.62**	$ 1.52	$ 0.16
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.41
Diluted		**$ 3.66**	$ 3.99	$ 2.38
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 3.75**	$ 4.05	$ 2.48
Diluted		**$ 3.66**	$ 3.99	$ 2.45

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the years ended December 31	**Note**	**2005**	**2004**	**2003**
Net Earnings U.S. GAAP		**$ 3,252**	$ 3,733	$ 2,349
Change in Fair Value of Financial Instruments	*B,F*			4
Foreign Currency Translation Adjustment	*D*	**573**	420	1,046
Change in Accounting Policy				6
Comprehensive Income		**$ 3,825**	$ 4,153	$ 3,405

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME

For the years ended December 31	**Note**	**2005**	**2004**	**2003**
Balance, Beginning of Year		**$ 1,025**	$ 605	$ (451)
Change in Fair Value of Financial Instruments	*B,F*			4
Foreign Currency Translation Adjustment	*D*	**573**	420	1,046
Change in Accounting Policy				6
Balance, End of Year		**$ 1,598**	$ 1,025	$ 605

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the years ended December 31	**2005**	**2004**	**2003**
Retained Earnings, Beginning of Year	**$ 7,955**	$ 5,076	$ 3,325
Net Earnings	**3,252**	3,733	2,349
Dividends on Common Shares	**(238)**	(183)	(139)
Charges for Normal Issuer Bid	**(1,642)**	(671)	(468)
Change in Accounting Policy			9
Retained Earnings, End of Year	**$ 9,327**	$ 7,955	$ 5,076

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

CONDENSED CONSOLIDATED BALANCE SHEET

		2005		2004	
As at December 31	**Note**	**As reported**	**U.S. GAAP**	**As reported**	**U.S. GAAP**
Assets					
Current Assets	*A,B*	**$ 3,604**	**$ 3,603**	$ 3,505	$ 3,497
Property, Plant and Equipment (includes unproved properties of $2,470 and $2,740 as of December 31, 2005 and 2004, respectively)	*A,G*	**39,339**	**39,224**	33,838	33,725
Accumulated Depreciation, Depletion and Amortization		**(14,458)**	**(14,383)**	(11,335)	(11,318)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**24,881**	**24,841**	22,503	22,407
Investments and Other Assets	*B*	**496**	**491**	334	330
Risk Management	*B*	**530**	**530**	87	87
Assets of Discontinued Operations		**2,113**	**2,113**	2,325	2,310
Goodwill		**2,524**	**2,524**	2,459	2,459
		$ 34,148	**$ 34,102**	$ 31,213	$ 31,090
Liabilities and Shareholders Equity					
Current Liabilities	*A,B*	**$ 4,871**	**$ 4,821**	$ 2,947	$ 2,950
Long-Term Debt		**6,703**	**6,703**	7,742	7,742
Other Liabilities	*B*	**93**	**22**	118	64
Risk Management	*B*	**102**	**102**	192	178
Asset Retirement Obligation	*G*	**816**	**816**	611	611
Liabilities of Discontinued Operations	*A,B*	**267**	**267**	213	172
Future Income Taxes	*E,G*	**5,289**	**5,153**	5,082	5,038
		18,141	**17,884**	16,905	16,755
Share Capital	*C*				
Common Shares, no par value		**5,131**	**5,160**	5,299	5,317
Outstanding: 2005 854.9 million shares					
2004 900.6 million shares					
Share Options, net				10	10
Paid in Surplus		**133**	**133**	28	28
Retained Earnings		**9,481**	**9,327**	7,935	7,955
Foreign Currency Translation Adjustment	*D*	**1,262**		1,036	
Accumulated Other Comprehensive Income			**1,598**		1,025
		16,007	**16,218**	14,308	14,335
		$ 34,148	**$ 34,102**	$ 31,213	$ 31,090

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

As at December 31	Note	2005 As reported	2005 U.S. GAAP	2004 As reported	2004 U.S. GAAP
Assets of Discontinued Operations	*A,B*	**$ 3,163**	**$ 3,163**	$ 3,296	$ 3,284
Liabilities of Discontinued Operations	*A,B*	**705**	**680**	649	723

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PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS U.S. GAAP

For the years ended December 31	**2005**	**2004**	**2003**
Operating Activities			
Net earnings from continuing operations	**$ 2,699**	$ 2,315	$ 2,127
Depreciation, depletion and amortization	**2,714**	2,348	1,953
Future income taxes	**(4)**	178	463
Unrealized loss (gain) on risk management	**668**	(116)	31
Unrealized foreign exchange gain	**(50)**	(285)	(545)
Accretion of asset retirement obligation	**37**	22	17
Gain on divestitures		(59)	(1)
Other	**174**	99	57
Cash flow from discontinued operations	**464**	478	357
Net change in other assets and liabilities	**(281)**	(176)	(84)
Net change in non-cash working capital from continuing operations	**497**	1,565	(744)
Net change in non-cash working capital from discontinued operations	**(187)**	(1,778)	673
Cash From Operating Activities	**$ 6,731**	$ 4,591	$ 4,304
Cash Used in Investing Activities	**$ (3,942)**	$ (4,259)	$ (3,729)
Cash (Used in) From Financing Activities	**$ (3,275)**	$ 163	$ (542)

Notes:

A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP 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 once realized. Currently, Management has not designated any of the financial instruments as hedges.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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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, 2005, under Canadian GAAP a $40 million deferred gain remains.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards (SFAS) 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded 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 SFAS 133.

Unrealized gain/(loss) on derivatives related to:

For the years ended December 31	**2005**	**2004**	**2003**
Commodity Prices (Revenues, net of royalties)	**$ (703)**	$ 76	$ (205)
Interest and Currency Swaps (Interest, net)	**(9)**	(29)	70
Total Unrealized (Loss) Gain	**$ (712)**	$ 47	$ (135)
Amounts Allocated to Continuing Operations	**$ (668)**	$ 116	$ (31)
Amounts Allocated to Discontinued Operations	**(44)**	(69)	(104)
	$ (712)	$ 47	$ (135)

As at December 31, 2005, it is estimated that over the following 12 months, $0.08 million ($0.05 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 (FIN) 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.(CPL), 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.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

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

For the years ended December 31	2005	2004	2003
Net Earnings Before Income Tax U.S. GAAP	**$ 3,900**	$ 3,052	$ 2,471
Canadian Statutory Rate	**37.9%**	39.1%	41.0%
Expected Income Tax	**1,478**	1,193	1,013
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**207**	192	231
Canadian resource allowance	**(202)**	(246)	(258)
Canadian resource allowance on unrealized risk management losses		(10)	
Statutory and other rate differences	**(235)**	(50)	(44)
Effect of tax rate reductions		(109)	(359)
Non-taxable capital gains	**(24)**	(91)	(119)
Previously unrecognized capital losses		17	(119)
Tax basis retained on divestitures	**(68)**	(169)	
Large corporations tax	**25**	24	27
Other	**20**	(14)	(28)
Income Tax U.S. GAAP	**$ 1,201**	$ 737	$ 344
Effective Tax Rate	**30.7%**	24.1%	13.9%

The net future income tax liability is comprised of:

As at December 31	2005	2004
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,407**	$ 4,354
Timing of partnership items	**1,226**	975
Future Tax Assets		
Net operating losses carried forward	**(47)**	(103)
Other	**(433)**	(188)
Net Future Income Tax Liability	**$ 5,153**	$ 5,038

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 SFAS 133. At December 31, 2005, accumulated other comprehensive income related to these items was a loss of $4.8 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. SFAS 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

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.

H) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented. Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31	**2005**	**2004**	**2003**
Dividends per share	**$ 0.28**	$ 0.20	$ 0.15

J) Recent Accounting Pronouncements

In the year end December 31, 2005, the Company adopted, for U.S. GAAP purposes, FIN 47, Accounting for Conditional Asset Retirement Obligations in order to address the diverse accounting practices which have developed with regard to the timing of recognition for asset retirement obligations. This interpretation did not have a material impact on its financial statements.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

Beginning with the year ended December 31, 2006, the Company will be required to adopt, for U.S. GAAP purposes, revised SFAS 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. Although the Company is in the process of assessing the impact of this amendment, the Company does not expect the amendments to have a material impact on its consolidated statements.

As of January 1, 2006, the Company will be required to adopt, for U.S. GAAP purposes, SFAS 154 Accounting Changes and Error Corrections, a replacement of APB Opinion No.20 and SFAS 3 . SFAS 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The Company does not expect this standard to have a material impact on its financial statements.

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, 2005, 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 management with the participation of the 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, 2005, 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), and is independent as that term is defined in the rules of the New York Stock Exchange.

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, 2005, 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, 2005, 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 Financing Arrangements in the registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2005, 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 for the fiscal year ended December 31, 2005, 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, 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., P.O. Box 2850, 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 2006 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 Secretarial 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 17, 2006.

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	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
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 GLJ Petroleum Consultants Ltd.

QuickLinks

ENCANA CORPORATION ANNUAL INFORMATION FORM