ENCANA™

ANNUAL INFORMATION FORM

February 23, 2007

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2006. 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 benefits of this strategy, Suffield development plans, potential shut-ins and the possible receipt of royalty credits, the effect of Alberta Energy & Utilities Board commingling guidelines, 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, the timing of completion of the Foster Creek and Christina Lake expansions, the anticipated capacities of and the timing of capacity expansions for the Wood River and Borger refineries, anticipated capacity for and timing of expansion of the Steeprock natural gas plant, the development of the Jonah area, the potential for natural gas resource play development on the Foix permit lands, reserves estimates, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and divestiture plans, including farmout plans and net cash flows.

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 market optimization 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, the ability of EnCana and ConocoPhillips to successfully manage and operate the integrated North American heavy oil business and the ability of the parties to obtain necessary regulatory approvals, refining and marketing margins, potential disruption or unexpected technical difficulties in developing new products and manufacturing processes, potential failure of new products to achieve acceptance in the market, unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities, unexpected difficulties in manufacturing, transporting or refining synthetic crude oil, 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 construction of gas storage facilities, wells and pipelines, 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, 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, except as required by law, 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 reserves quantities based on constant prices should not be material. EnCana concurs with this assessment.

EnCana has disclosed proved reserves 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, 2006. 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, 2006:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance or Formation
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
EnCana Heritage Lands	100	Alberta
1140102 Alberta Ltd.	100	Alberta
EnCana Resource Developments Ltd.(2)	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Effective January 1, 2007, EnCana Resource Developments Ltd. amalgamated with its wholly owned subsidiary, EnCana Oil & Gas Co. Ltd., with the resulting name of EnCana Oil & Gas Co. Ltd.

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, 2006.

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's other operations include the transportation and marketing of crude oil, natural gas and natural gas liquids, as well as the refining of crude oil and the marketing of refined petroleum products. EnCana pursues profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. The Corporation is also engaged in select exploration 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. Beginning in 2004, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. As part of its ongoing strategic focus, the Corporation has completed a number of acquisitions while continuing with the divestiture of its non-core assets. A portion of the divestiture proceeds were used to fund EnCana's normal course issuer bid program. In 2006, EnCana purchased approximately 85.6 million shares under the program for a total cost of approximately $4.2 billion.

In January of 2007, EnCana, with ConocoPhillips, completed the creation of an integrated heavy oil business. This venture provides greater certainty of execution for EnCana's oilsands projects and gives EnCana immediate participation in the North American refining industry.

Effective January 1, 2007, EnCana has been reorganized into six operating divisions:

- Canadian Plains Division, which includes the majority of EnCana's legacy oil and gas assets
- Canadian Foothills Division, which includes the majority of EnCana's Canadian natural gas resource plays
- USA Division, which includes the majority of the Corporation's upstream U.S. assets, including its key resource plays
- Integrated Oilsands Division, which includes all of the assets within the newly created integrated heavy oil business (including the U.S. refinery assets), as well as the Corporation's other oilsands interests and the natural gas assets on the Cold Lake Air Weapons Range
- Offshore & International Division, which includes the Corporation's offshore East Coast Canadian assets as well as assets in Brazil, the Middle East, Greenland and France
- Midstream & Marketing Division, which continues to provide coordination of the Corporation's natural gas and crude oil market optimization activities, and includes the Cavalier and Balzac power assets

In 2006, for financial reporting purposes, EnCana has defined its operations into the following segments: (i) Upstream; (ii) Market Optimization; and (iii) Corporate. All divisions are reported under Upstream with the exception of the Midstream & Marketing Division, which is reported under Market Optimization. In 2007, the Integrated Oilsands Division will be reported under a new Integrated Oilsands segment.

The following describes the significant events of the last three years. In this section, all divestiture proceeds are provided on a before tax basis unless otherwise noted.

2006 Projects:

- In November 2005, EnCana announced plans to examine a number of proposals from other companies who were interested in participating in the development of EnCana's oilsands assets. In October 2006, EnCana announced it had entered into an agreement with ConocoPhillips to create an integrated heavy oil business consisting of upstream and downstream assets.

  The creation of the integrated heavy oil business was completed on January 3, 2007. The business is comprised of two 50/50 operating entities, one Canadian upstream enterprise managed by EnCana and one U.S. downstream enterprise managed by ConocoPhillips, with both EnCana and ConocoPhillips contributing equally valued assets and equity. For further information refer to the "Narrative Description of the Business" in this annual information form.

2006 Acquisitions:

- In June 2006, EnCana increased its working interest in the Deep Bossier play in East Texas from 30 percent to 50 percent and purchased an additional 7,600 net acres in Robertson County for approximately $250 million. The transaction resulted in additional production of approximately 4.3 million cubic feet per day of natural gas.

2006 Divestitures:

- In February 2006, EnCana completed the sale of all of its oil and pipeline interests in Ecuador for approximately $1.4 billion. The Ecuador assets included 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.

  Subsequent to the divestiture, in May 2006, the Government of Ecuador seized the Block 15 assets. As part of the sales agreement with the purchaser, EnCana had agreed to indemnify the purchaser for certain defined losses. In August 2006, EnCana paid an indemnity claim of approximately $265 million, relating to the Block 15 assets, calculated in accordance with the terms of the agreement. EnCana expects no further liability.

- In February 2006, a subsidiary of EnCana sold Entrega Gas Pipeline LLC for approximately $244 million. As part of the sale, EnCana committed approximately 500 million cubic feet per day to the Rockies Express Project.

- In May 2006, a subsidiary of EnCana completed the first of two phases in the sale of its non-strategic natural gas storage assets for proceeds of approximately $1.3 billion. Phase one storage assets included facilities in Alberta, Oklahoma and Louisiana.

- In August 2006, a subsidiary of EnCana completed the sale of its 50 percent interest in the Chinook heavy oil discovery in Block BM-C-7 offshore Brazil for proceeds of approximately $367 million. EnCana continues to hold a non-operated working interest in 10 deep water exploration blocks offshore Brazil.

- In November 2006, a subsidiary of EnCana completed the second phase in the sale of its non-strategic natural gas storage assets for approximately $215 million. Phase two of the asset sale included the Wild Goose storage facility in California.

- In December 2006, a subsidiary of EnCana completed the divestiture of the remainder of its NGL assets, the majority of which were sold in 2005, by selling its final 10 percent share of the Empress straddle plant joint venture facility for approximately $13 million.

In addition to the transactions completed in 2006, EnCana has a number of divestitures that were completed after December 31, 2006 or are still in progress:

In September 2006, EnCana announced its intention to divest its assets in northern Canada. The assets include all of its Mackenzie Delta / Beaufort Sea licenses and discoveries as well as all of its Arctic Islands licenses. In December 2006, EnCana completed the sale of a portion of its northern Canada assets.

In January 2007, a subsidiary of EnCana completed the sale of all of its interests in its Chad exploration assets for approximately $203 million. The Chad assets included a 50 percent working interest in approximately 54 million gross acres in seven sedimentary basins.

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 provides terminalling services to EnCana at Methanex's terminal facilities at Kitimat, British Columbia, and Provident provides terminalling services to EnCana at Provident's terminal facilities at Redwater, Alberta.

EnCana now imports 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, 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 regulated pipeline project, from Meeker Hub, Colorado to Wamsutter, Wyoming. This segment of the pipeline came into service in February 2006.

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 December 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 Divestitures:

- In May 2005, subsidiaries of EnCana completed the sale of the Corporation's Gulf of Mexico assets for approximately $2.1 billion. 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 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 NGL marketer. EnCana had previously acquired the 25 percent minority interest in the Kinetic partnership earlier in the year.

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 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 Divestitures:

- In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources ("Petrovera"), an Alberta partnership that produced 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 licenses covering more than 740,000 net acres in the central North Sea.
- 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.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2006. The map also identifies the Borger and Wood River refineries that were contributed to the integrated heavy oil business by ConocoPhillips in January 2007.

The vast majority of EnCana's operations are located in Canada and the U.S., while the Offshore & International Division is mainly focusing on opportunities off the East Coast of Canada, in Brazil, the Middle East, Greenland and France.

At December 31, 2006, EnCana had net proved reserves of approximately 12.4 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 62 percent of total natural gas reserves, approximately 75 percent of crude oil and NGLs reserves excluding bitumen and approximately 13 percent of bitumen reserves. See "Reserves and Other Oil and Gas Information" in this annual information form.

Within western Canada, EnCana has an industry-leading land position of approximately 23.8 million gross acres (approximately 21.0 million net acres, of which approximately 12.1 million net acres are undeveloped). The mineral rights on approximately 38 percent 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. In 2006, EnCana had core capital expenditures in Canada of approximately $4,015 million ($3,984 million in western Canada) and drilled approximately 3,009 net wells (3,007 in western Canada).

In the U.S., EnCana's landholdings are approximately 6.4 million acres (approximately 5.5 million net acres, of which approximately 5.0 million net acres are undeveloped), with the majority in Colorado, Wyoming, Washington and Texas. In 2006, EnCana had core capital expenditures of approximately $2,061 million and drilled approximately 639 net wells within the U.S.

As noted previously, EnCana's operations are divided into six divisions. The following narrative describes each division in greater detail.

Canadian Plains Division

The Canadian Plains Division encompasses the majority of EnCana's legacy natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation's crude oil (excluding in-situ oilsands) development and production activities in Alberta and Saskatchewan. Two key resource plays are located in the Canadian Plains Division: (i) Shallow Gas; and (ii) Pelican Lake. The Shallow Gas key resource play is contained within the Suffield, Langevin and Brooks North areas.

In 2006, the Canadian Plains Division had core capital expenditures of approximately $768 million and drilled approximately 1,635 net wells. EnCana's 2007 core capital investment in the Canadian Plains Division is projected to be approximately $870 million, which includes the drilling of approximately 2,100 net wells.

The following table summarizes landholdings for the Canadian Plains Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	918	904	69	68	987	972	98%
Brooks North	556	554	12	12	568	566	100%
Langevin	1,198	1,080	1,231	1,143	2,429	2,223	92%
Drumheller	360	349	20	18	380	367	97%
Pelican Lake	139	139	277	262	416	401	96%
Weyburn	91	80	587	580	678	660	97%
Other	926	879	833	765	1,759	1,644	93%
Canadian Plains Total	4,188	3,985	3,029	2,848	7,217	6,833	95%

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

Production (annual average)	Natural Gas (MMcf/d) 2006	2005	Crude Oil and NGLs (bbls/d) 2006	2005	Total Production (MMcfe/d) 2006	2005
Suffield	241	243	17,350	20,756	345	368
Brooks North	272	283	726	1,155	276	290
Langevin	238	255	10,400	12,405	300	329
Drumheller	104	107	2,251	2,654	118	123
Pelican Lake	2	4	23,563	25,752	143	159
Weyburn	—	—	15,136	13,562	91	81
Other	49	47	7,566	8,382	94	97
Canadian Plains Total	906	939	76,992	84,666	1,367	1,447

Note:

(1) The Shallow Gas key resource play, located mainly in the Suffield, Brooks North and Langevin areas, had 2006 average production of approximately 600 million cubic feet per day (625 million cubic feet per day in 2005).

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	8,790	8,759	732	730	9,522	9,489
Brooks North	5,949	5,859	46	46	5,995	5,905
Langevin	6,042	5,642	233	227	6,275	5,869
Drumheller	1,154	1,119	97	95	1,251	1,214
Pelican Lake	29	29	452	452	481	481
Weyburn	—	—	999	456	999	456
Other	1,127	1,108	673	635	1,800	1,743
Canadian Plains Total	23,091	22,516	3,232	2,641	26,323	25,157

Note:

(1) At December 31, 2006, the Shallow Gas key resource play had 20,192 gross producing gas wells (19,682 net gas wells).

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

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. EnCana plans to continue development of its shallow gas and heavy oil resources at Suffield. In 2007, as part of its ongoing application to continue shallow gas infill drilling in the National Wildlife Area, EnCana will be preparing an Environmental Impact Statement and participating in an Alberta Energy & Utilities Board ("EUB") joint panel hearing as part of the Canadian Environmental Assessment Act. In 2006, EnCana drilled approximately 460 net wells in the area and production averaged approximately 241 million cubic feet per day of natural gas.

Brooks North

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. In 2006, EnCana drilled approximately 473 net wells in the area and production averaged approximately 272 million cubic feet per day of natural gas. Completion operations in 2007 are expected to benefit significantly from the recent EUB self-declared commingling process, which became effective December 15, 2006. It is anticipated that the new process will allow EnCana to complete additional zones in a well bore at minimal incremental cost.

Langevin

The Langevin area produces predominantly shallow gas from the Upper Cretaceous formations in southeast Alberta and southwestern Saskatchewan. Certain parts of this area are included in EnCana's Shallow Gas key resource play. Development of this area focuses on infill drilling and optimization of existing wells, and is largely comprised of EnCana fee title lands. In 2006, EnCana drilled approximately 426 net wells in the area and production averaged approximately 238 million cubic feet per day of natural gas.

Drumheller

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons in the Drumheller area of southern Alberta. The area is mainly a conventional Mannville gas play, and is largely comprised of EnCana fee title lands. In 2006, EnCana drilled approximately 167 net wells in the area and production averaged approximately 104 million cubic feet per day of natural gas.

Pelican Lake

Pelican Lake is one of EnCana's key resource plays producing crude oil in northeast Alberta. In 2006, EnCana continued to expand its waterflood program to approximately 80 percent of the field at Pelican Lake, while expanding the polymer pilot from 11 injection wells to 37 injection wells. In order to process the increased fluid volumes associated with the waterflood and polymer projects, EnCana has expanded the facility infrastructure, with additional facility projects to be completed in 2007. EnCana reached payout at Pelican Lake in 2006, changing the royalty from one percent of gross revenues to 25 percent of net revenues. The success of the waterflood program at Pelican Lake increased 2006 crude oil production by approximately five percent compared to 2005; however, because EnCana reached payout, after-royalties production decreased.

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.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southeast Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area of the field with a carbon dioxide ("CO_2") miscible flood project. In 2006, EnCana focused on continuing its infill drilling program with 56 new wells in the unit. As of December 31, 2006, there were 44 patterns on CO_2 injection out of a planned total of 75 patterns.

Canadian Foothills Division

The Canadian Foothills Division includes EnCana's key natural gas growth assets in British Columbia and Alberta. Four key resource plays are located in the Canadian Foothills Division: (i) Greater Sierra; (ii) Cutbank Ridge; (iii) Bighorn; and (iv) Coalbed Methane Integrated ("CBM Integrated"). The CBM Integrated key resource play (Horseshoe Canyon coalbed methane and commingled shallow gas), is completely contained within the Clearwater business unit.

In 2006, the Canadian Foothills Division had core capital expenditures of approximately $2,467 million and drilled approximately 1,274 net wells. EnCana's 2007 core capital investment in the Canadian Foothills Division is projected to be approximately $2,150 million, which includes the drilling of approximately 1,370 net wells.

The following table summarizes landholdings for the Canadian Foothills Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	645	568	2,470	2,111	3,115	2,679	86%
Cutbank Ridge	227	194	851	762	1,078	956	89%
Bighorn	261	147	774	478	1,035	625	60%
Clearwater	3,434	3,050	3,509	3,293	6,943	6,343	91%
Sexsmith/Hythe/Saddle Hills	362	225	259	195	621	420	68%
Other	300	202	1,386	1,061	1,686	1,263	75%
Canadian Foothills Total	5,229	4,386	9,249	7,900	14,478	12,286	85%

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)	
	2006	2005	2006	2005	2006	2005
Greater Sierra	213	219	837	793	218	224
Cutbank Ridge	170	92	82	—	170	92
Bighorn	91	55	1,480	867	100	60
Clearwater	483	447	11,555	12,330	552	521
Sexsmith/Hythe/Saddle Hills	93	99	2,046	1,989	105	111
Other	116	137	3,370	3,717	136	159
Canadian Foothills Total	1,166	1,049	19,370	19,696	1,281	1,167

Note:

(1) The CBM Integrated key resource play, located within the Clearwater business unit, had 2006 average production of approximately 194 million cubic feet per day (112 million cubic feet per day in 2005).

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	829	772	3	3	832	775
Cutbank Ridge	370	330	—	—	370	330
Bighorn	205	128	1	—	206	128
Clearwater	7,103	6,314	204	111	7,307	6,425
Sexsmith/Hythe/Saddle Hills	329	261	67	50	396	311
Other	577	427	186	101	763	528
Canadian Foothills Total	9,413	8,232	461	265	9,874	8,497

Note:

(1) At December 31, 2006, the CBM Integrated key resource play had 3,137 gross producing gas wells (2,890 net gas wells).

The following describes EnCana's major producing areas or activities in the Canadian Foothills Division.

Greater Sierra

The Greater Sierra area of northeast British Columbia is one of EnCana's key natural gas resource plays. Average natural gas production in the area was approximately 213 million cubic feet per day in 2006. Production has remained relatively constant over the past two years as EnCana has reduced capital expenditures, and is currently targeting a drilling program that will continue to maintain current production levels. EnCana is selectively farming out a small portion of its Greater Sierra land position to third parties.

As at December 31, 2006, 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.

Cutbank Ridge

Cutbank Ridge is a key natural gas resource play located in the Canadian Rocky Mountain foothills, southwest of Dawson Creek, British Columbia. Key producing horizons in Cutbank Ridge include the Cadomin, Doig and Montney zones. The majority of the Corporation's lands in this area were purchased in 2003. In 2006, EnCana drilled approximately 116 net natural gas wells at Cutbank Ridge and production averaged approximately 170 million cubic feet per day of natural gas.

In 2006, a significant extension to the Cutbank Ridge resource play was added with the addition of the Montney zone. EnCana has had a small number of wells producing from the Montney formation as far back as 1999, and the application of new technologies has started to achieve positive results within the formation. At year end 2006, approximately 18 percent of the wells in Cutbank Ridge were producing out of the Montney formation, with 58 wells (25 drilled in 2006) producing approximately 43 million cubic feet of natural gas per day.

In order to facilitate increased production from Cutbank Ridge, EnCana completed phase one of the Steeprock natural gas processing plant in the fourth quarter of 2006. The plant, located approximately 60 kilometres south of Dawson Creek, British Columbia, is expected to have a licensed capacity of 198 million cubic feet of natural gas per day once both phases are complete. Phase one of the plant has a capacity of approximately 70 million cubic feet per day with a current throughput of approximately 60 million cubic feet per day. EnCana anticipates that phase two will be completed in the first half of 2008.

Bighorn

The Bighorn area in west central Alberta is another of EnCana's key natural gas resource plays, focusing on exploitation of multi-zone stacked Cretaceous sands in the Deep Basin. EnCana has an average working interest of approximately 60 percent in approximately 1,035,000 gross acres (625,000 net acres) of land in the Bighorn area. The primary producing properties in Bighorn are Wild River, Resthaven, Kakwa, and Berland. In 2006, EnCana drilled approximately 52 net wells in the area and production averaged approximately 91 million cubic feet per day of sweet natural gas.

EnCana has a working interest in a number of gas plants within Bighorn. The Wild River plant, in which EnCana holds a 70 percent working interest, was expanded to a capacity of approximately 30 million cubic feet per day in January 2006. In April 2006, the Resthaven plant, in which EnCana has a 65 percent working interest, was brought on stream, with a capacity of approximately 100 million cubic feet of natural gas per day. The Kakwa gas plant, with a capacity of approximately 30 million cubic feet per day, was commissioned in September 2006, and operated at close to capacity through the fourth quarter of 2006. EnCana owns 50 percent of this plant and has firm processing capacity for the remaining 50 percent. The Berland River plant was recently expanded, and EnCana now has a 24 percent working interest and approximately 40 million cubic feet per day net capacity.

The new commingling guidelines announced by the EUB in December 2006, have a positive impact on operations in the business unit. The majority of Bighorn's land base falls within the EUB's Deep Basin

Development Entity No. 2. The primary benefits for the business unit are significant cost reductions on new well completions and the potential to access additional zones with the same number of fractures.

Clearwater

The Clearwater business unit extends from the U.S. border to just north of Edmonton, and was created by merging the former Chinook and Parkland business units. The primary focus of Clearwater is the CBM Integrated key natural gas resource play; however, Clearwater is also charged with the development of the Mannville coalbed methane fairway, and deeper Cretaceous reservoirs. EnCana holds a combination of both fee lands, where it owns the mineral rights, and crown lands within Clearwater. In 2006, EnCana drilled 729 net CBM Integrated wells, and production averaged approximately 194 million cubic feet per day of natural gas from the CBM Integrated resource play.

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.

USA Division

EnCana's operations in the USA Division 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. The majority of the production in the USA Division is from the following four key resource plays: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth. The USA Division also has interests in natural gas gathering and processing assets, primarily in Colorado, Wyoming, Texas and Utah.

In 2006, the USA Division had core capital expenditures of approximately $2,061 million and drilled approximately 639 net wells. EnCana's 2007 core capital investment in the USA Division is projected to be approximately $1,890 million, which includes the drilling of approximately 660 net wells.

The following table summarizes landholdings for the USA Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Jonah	12	10	147	141	159	151	95%
Piceance	246	233	815	763	1,061	996	94%
East Texas	98	59	669	614	767	673	88%
Fort Worth	37	35	168	161	205	196	96%
Maverick Basin	4	4	479	339	483	343	71%
Columbia River Basin	—	—	823	811	823	811	99%
Other	276	177	2,588	2,164	2,864	2,341	82%
USA Total	673	518	5,689	4,993	6,362	5,511	87%

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

Production (annual average)	Natural Gas (MMcf/d) 2006	2005	Crude Oil and NGLs (bbls/d) 2006	2005	Total Production (MMcfe/d) 2006	2005
Jonah	464	435	4,257	3,939	489	459
Piceance	326	307	2,416	2,965	341	325
East Texas	99	90	277	304	100	92
Fort Worth	101	70	607	345	105	72
Other	192	193	5,401	6,337	225	230
USA Total	1,182	1,095	12,958	13,890	1,260	1,178

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Jonah	669	609	—	—	669	609
Piceance	2,229	2,003	—	—	2,229	2,003
East Texas	827	412	12	6	839	418
Fort Worth	639	560	13	12	652	572
Other	3,014	1,414	17	5	3,031	1,419
USA Total	7,378	4,998	42	23	7,420	5,021

The following describes EnCana's major producing areas or activities in the USA Division.

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 produces from the Lance formation, which contains vertically stacked sands that exist at depths between 8,500 and 11,500 feet. The wells are stimulated with multi-stage advanced hydraulic fracturing techniques.

In March 2006, EnCana obtained a favorable Environmental Impact Statement regulatory approval from the U.S. Bureau of Land Management. The approval provides EnCana access to 600 remaining 10-acre spacing locations and additional locations at tighter spacing, as required, to achieve optimal recovery. In 2006, EnCana drilled approximately 163 net wells in the Jonah area, up from 104 net wells in 2005. Daily production of natural gas averaged approximately 464 million cubic feet in 2006 compared to approximately 435 million cubic feet in 2005.

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. The May 2004 acquisition of Tom Brown included properties and natural gas production in the basin. In 2006, EnCana drilled approximately 220 net wells in the basin, compared to 266 in 2005. Despite drilling fewer wells in 2006, production of natural gas has grown to an average of approximately 326 million cubic feet per day from approximately 307 million cubic feet per day in 2005.

In 2006, EnCana finalized four agreements to jointly develop portions of the Piceance Basin. Over the next three years, it is expected that EnCana will drill approximately 267 wells with outside funds and EnCana's partners will fund the drilling of approximately 182 wells, allowing the third parties to earn approximately 20,000 net acres.

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 key resource plays. In July 2006, EnCana increased its working interest in the Deep Bossier play in East Texas from 30 percent to 50 percent through a property acquisition. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2006, EnCana drilled approximately 59 net wells in the basin and production averaged approximately 99 million cubic feet per day of natural gas.

Fort Worth

EnCana produces natural gas and associated NGLs in the Fort Worth Basin in north Texas. The Fort Worth Basin 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. 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 97 net wells in the basin in 2006 and production averaged approximately 101 million cubic feet per day of natural gas.

Maverick Basin

EnCana controls approximately 479,000 undeveloped gross acres (339,000 net acres) in the Maverick Basin of southwest Texas. This acreage, purchased in September 2005 for approximately $148 million, contains significant exploratory potential in the Pearsall Shale, plus multi-zone potential in the uphole section. In 2007, the Corporation expects to drill up to six wells, both vertical and horizontal, to assess this potential shale play.

Columbia River Basin

EnCana holds approximately 823,000 undeveloped gross acres (811,000 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. In 2006, EnCana drilled two wells to a depth of approximately 14,000 feet. Log and completions data obtained from these wells is currently under review. A third well is being drilled on the play, and is expected to reach total depth in the second quarter of 2007. EnCana's operations in the Columbia River Basin are largely funded by an outside partner who will eventually earn an interest in this play.

Gathering & Processing Facilities

EnCana owns and operates various gas gathering and processing facilities. Near Rifle, Colorado, EnCana owns a refrigeration plant with a capacity of approximately 440 million cubic feet per day and over 675 kilometres of pipelines. The Corporation's gathering and processing facilities near Rangely, Colorado, include over 1,620 kilometres of pipelines and a processing facility with a capacity of approximately 60 million cubic feet per day. In Texas, EnCana's gathering facilities include field compression and over 360 kilometres of pipelines. Near Ft. Lupton, Colorado, the gathering and processing facilities include field compression, over 1,000 kilometres of pipelines and a processing facility with a capacity of approximately 90 million cubic feet per day. Near Moab, Utah, EnCana owns a cryogenic natural gas processing plant with a capacity of approximately 60 million cubic feet per day. In west central Wyoming, EnCana has field compression, over 500 kilometres of pipelines and a refrigeration facility with a capacity of approximately 70 million cubic feet per day.

Integrated Oilsands Division

The Integrated Oilsands Division includes all of the assets within the newly created integrated heavy oil business with ConocoPhillips described below, as well as the Corporation's other oilsands interests and the natural gas assets on the Cold Lake Air Weapons Range. The Division has assets in both Canada and the United States, and contains two key crude oil resource plays: (i) Foster Creek; and (ii) Christina Lake. As at December 31, 2006, the Corporation held oilsands rights of approximately 860,000 gross acres (754,000 net acres) within the Athabasca and Cold Lake oilsands areas, as well as the exclusive rights to lease an additional 505,000 net acres on the Cold Lake Air Weapons Range.

In 2006, the Integrated Oilsands Division had core capital expenditures of approximately $745 million and drilled approximately 98 net wells (eight oil wells and 90 gas wells). EnCana's 2007 core capital investment in the Integrated Oilsands Division is projected to be approximately $850 million which includes approximately $770 million related to the drilling of approximately 32 net wells and refinery expansion projects associated with the newly created integrated heavy oil business.

The information relating to landholdings, production and producing wells in the following tables is as of December 31, 2006, prior to the contribution of Foster Creek and Christina Lake into the integrated heavy oil business with ConocoPhillips.

The following table summarizes landholdings for the Integrated Oilsands Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Cold Lake Air Weapons Range	373	351	449	445	822	796	97%
Foster Creek	8	8	51	51	59	59	100%
Christina Lake	1	1	43	43	44	44	100%
Borealis	—	—	338	338	338	338	100%
Other	163	105	671	508	834	613	74%
Integrated Oilsands Total	545	465	1,552	1,385	2,097	1,850	88%

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)	
	2006	2005	2006	2005	2006	2005
Cold Lake Air Weapons Range	106	129	—	—	106	129
Foster Creek	—	—	36,910	29,019	221	174
Christina Lake	—	—	5,858	5,360	35	32
Other	7	8	5,185	4,176	38	33
Integrated Oilsands Total	113	137	47,953	38,555	400	368

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Cold Lake Air Weapons Range	642	618	—	—	642	618
Foster Creek	—	—	62	62	62	62
Christina Lake	4	4	8	8	12	12
Other	77	58	79	66	156	124
Integrated Oilsands Total	723	680	149	136	872	816

The following describes EnCana's major producing areas or activities in the Integrated Oilsands Division.

Cold Lake Air Weapons Range

EnCana produces natural gas from the Cold Lake Air Weapons Range located in northeast Alberta. EnCana holds surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range which were granted by the Government of Canada. The majority of EnCana's natural gas production in the area is processed through wholly owned and operated compression facilities. In 2006, natural gas production was impacted by the September 2003 EUB 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 of approximately 22 million cubic feet per day in 2006, and 22 million cubic feet per day in 2005. No additional wells were shut-in during 2005 or 2006. The Alberta Government's Department of Energy ("ADOE") 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.

There is a potential that approximately 13 million cubic feet per day of natural gas production will be shut-in commencing in April 2007, due to additional risk of recovery of the bitumen resources in the area. A hearing on this matter is expected to commence in February 2007.

Foster Creek

As of December 31, 2006, EnCana had a 100 percent working interest in Foster Creek, one of the Corporation's key crude oil resource plays. EnCana holds surface access rights from the Governments of Canada and Alberta and oilsands rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range which were granted by the Government of Alberta. Additionally, EnCana has the exclusive rights to lease several hundred thousand acres of oilsands rights in other areas on the Cold Lake Air Weapons Range. EnCana is currently operating a thermal oil recovery project in the Foster Creek area using steam-assisted gravity drainage ("SAGD") technology.

In the fourth quarter of 2006, EnCana completed the second stage of an expansion that added an additional 20,000 barrels per day of capacity, increasing production capacity at Foster Creek to approximately 60,000 barrels per day. Current expansions already underway are expected to increase production capacity to approximately 120,000 barrels per day by the end of 2009.

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 new 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, 2006, EnCana had 45 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to continue to utilize this technology on new SAGD wells.

EnCana is also focused on reducing its 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. Results from the Vapex pilot are being utilized during investigations into new production strategies for bitumen recovery. 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

Christina Lake is one of EnCana's newest key resource plays. As of December 31, 2006, EnCana had a 100 percent owned thermal crude oil recovery pilot project at Christina Lake that also uses SAGD technology. In 2006, the Corporation approved an expansion that is expected to increase production capacity to approximately 18,000 barrels per day by the second half of 2008. In 2006, EnCana completed the installation of a remote water disposal system for the plant.

In 2004, EnCana commenced a pilot SAP program at Christina Lake. This process mixes a small amount of solvent with steam to enhance recovery. EnCana continues to produce and monitor current SAP pilot wells and recently began work with another SAP well test in the main reservoir.

Borealis

EnCana has a 100 percent working interest in approximately 338,000 acres in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. Borealis is not included in the venture with

ConocoPhillips. Since 2000, the Corporation has drilled approximately 190 delineation wells in the area as of December 31, 2006. In 2007, EnCana plans to continue its stratigraphic well program by drilling approximately 50 wells to further delineate these lands. Environmental work is ongoing to support future applications for development.

Integrated Heavy Oil Business

On January 3, 2007, EnCana completed the creation of an integrated heavy oil business with ConocoPhillips. The integrated heavy oil business includes Canadian upstream assets contributed by EnCana and U.S. downstream assets contributed by ConocoPhillips.

The upstream portion of the integrated heavy oil business is conducted through FCCL Oil Sands Partnership (the "Upstream Partnership") which owns the Foster Creek and Christina Lake oilsands projects contributed by EnCana. EnCana and ConocoPhillips each own 50 percent of the Upstream Partnership. EnCana is the operating and managing partner of the Upstream Partnership. The downstream portion of the integrated heavy oil business is conducted through WRB Refining LLC ("WRB") which owns the Wood River and Borger refineries contributed by ConocoPhillips. EnCana and ConocoPhillips each own 50 percent of WRB; however, ConocoPhillips will hold a disproportionate economic interest in the Borger refinery for two years: 85 percent in 2007 and 65 percent in 2008. ConocoPhillips is the operator and manager of WRB. The Upstream Partnership has a Management Committee, while WRB has a Board of Directors; both are comprised of three EnCana and three ConocoPhillips representatives, with each company holding equal voting rights.

The goal of the Upstream Partnership is to increase current production of approximately 50,000 barrels per day to approximately 400,000 barrels per day of bitumen by 2015, with the intention to transport and sell the bitumen at major Alberta trading hubs.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 barrels per day of crude oil and approximately 50,000 barrels per day of NGLs. It processes mainly light-sour and medium-sour crude oil and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel, and natural gas liquids and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the mid-continent.

The Wood River refinery, located in Roxana, Illinois, has a current throughput of approximately 306,000 barrels per day, including approximately 30,000 barrels per day of bitumen capacity. It processes a mix of light-low-sulfur and heavy-high-sulfur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstock and asphalt. The gasoline and diesel are transported via pipelines to markets in the Midwest. The remaining products are transported via pipeline, truck, barge and railcar to markets in the Midwest.

The goal of WRB is to expand heavy oil processing capacity at the Wood River and Borger facilities from approximately 60,000 barrels per day to approximately 550,000 barrels per day (30,000 to 275,000 barrels per day of bitumen handling capacity) by 2015. WRB plans to purchase and transport all feedstocks for the refineries and sell the refined products.

Offshore & International Division

EnCana invests a small portion of its capital in exploration opportunities beyond its core geographic areas, primarily off the East Coast of Canada, in Brazil, the Middle East, Greenland and France. In 2006, EnCana's Offshore & International Division had core capital expenditures of approximately $106 million and drilled approximately four net wells. EnCana's 2007 core capital investment in the Offshore & International Division is projected to be approximately $88 million, which includes the drilling of approximately five net wells.

East Coast of Canada

At December 31, 2006, EnCana held an interest in approximately 2.7 million gross acres (1.7 million net acres) offshore the East Coast of Canada, which includes Nova Scotia and Newfoundland & Labrador. EnCana operates 10 of its 16 licenses in these areas and has an average working interest of approximately 61 percent.

EnCana is the operator of the Deep Panuke field, located offshore Nova Scotia, and has an approximate 85 percent working interest at December 31, 2006. EnCana continues to examine the potential economic viability of the Deep Panuke project. In June 2006, EnCana and the Province of Nova Scotia reached an Offshore Strategic Energy Agreement that established the framework for the potential development of Deep Panuke. Subsequently, in November 2006, EnCana filed the Development Plan Application with the Canada-Nova Scotia Offshore Petroleum Board. The filing included an Environmental Assessment Report and an application to the National Energy Board for approval of the construction and operation of an offshore pipeline.

Brazil

EnCana has non-operated interests in 10 deep and ultra-deep water exploration blocks offshore Brazil, nine of which are operated by Petrobras, the Brazilian national oil company. EnCana's landholdings on these offshore blocks total approximately 1.7 million gross acres (0.5 million net acres) with an average working interest of 31 percent. EnCana and its partners drilled one gross exploration well in 2006 in the Campos Basin.

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 50 percent working interest in Block 2, which encompasses most of the onshore lands in the State of Qatar and covers approximately 2.2 million gross acres (1.1 million net acres). In 2005, EnCana reached an agreement to farmout 50 percent of its working interest in the block. The farmout was approved by Qatar Petroleum in February 2006. Two gross wells are planned for the block in 2007.

EnCana also has a 50 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman. The blocks cover approximately 8.6 million gross acres (4.3 million net acres). Three gross wells are planned in 2007.

Greenland

EnCana has an 87 percent working interest in two exploration blocks offshore Greenland, comprising approximately 1.7 million gross acres (1.5 million net acres). In 2007, EnCana plans to farmout a portion of its interests on both blocks.

France

In February 2006, EnCana was granted a 100 percent interest in the Foix exploration permit, which encompasses approximately 859,000 gross acres in the onshore Aquitaine Basin in southwest France. The Corporation has plans for a multi-well exploration drilling program in 2007 to identify the potential for a natural gas resource play development.

Midstream & Marketing Division

EnCana's divisional marketing groups are focused on enhancing the netback price of the Corporation's proprietary production. Correspondingly, the Midstream & Marketing Division coordinates the 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.

Natural Gas Marketing

In 2006, approximately 89 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials, other producers and energy marketing companies. The remaining 11 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

EnCana mitigates the market risk associated with forecasted cash flows, by entering into various risk management contracts relating to produced natural gas. For 2007, after taking into account its risk management contracts, EnCana's gas sales price portfolio exposure consists of approximately 42 percent at an average fixed NYMEX price of approximately $8.49 per million cubic feet, approximately seven percent with an insured NYMEX strike price of approximately $6.00 per million cubic feet and approximately 51 percent unhedged. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2006.

Crude Oil Marketing

EnCana, through its operating divisions, sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (134,869 barrels per day in 2006 and 131,638 barrels per day in 2005). 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 2006, EnCana acted as exclusive agent for Canadian Oil Sands Limited ("COS") and marketed COS' Syncrude volumes of 47,583 barrels per day (81,019 barrels per day in 2005). The COS marketing agreement terminated in the second quarter of 2006. EnCana also provides marketing services to the ADOE (45,542 barrels per day in 2006 and 48,425 barrels per day in 2005). This agency agreement ends in the second quarter of 2007.

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, 2006.

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 operating divisions in Alberta's deregulated market. The physical assets include two, 106 megawatt gas-fired power plants in southern Alberta. 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 185 megawatts and its generation capacity is approximately 159 megawatts, excluding both the electricity requirements and generation capacity of the Integrated Oilsands Division.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana has retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's natural gas, crude oil and NGLs reserves annually since its inception. In 2006, EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd., and its U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton.

EnCana has a Reserves Committee of independent board members which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Reserves 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.

Reserves Quantities Information

EnCana's natural gas reserves increased approximately five percent in 2006 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,620 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 positive revisions of 213 billion cubic feet, or approximately two percent of proved natural gas reserves at the beginning of 2006. CBM Integrated accounted for the majority of the positive revisions in Canada. Downward revisions of 88 billion cubic feet in the U.S. were largely a consequence of proved undeveloped reserves being removed given planned moderation in activity levels over the next five years.

In 2005 and 2004, natural gas reserves increased from exploration and development drilling and acquisitions.

EnCana's crude oil and NGLs reserves were essentially unchanged at year-end 2006 in comparison to year-end 2005. Significant increases in proved reserves primarily at Christina Lake and Foster Creek were offset by the completion of the sale of EnCana's interests in Ecuador and negative revisions in Canada. The downward revision in Canada was a consequence of net reserves being reduced in light of higher calculated average royalty rates at Foster Creek stemming from an almost two fold increase in field prices relative to the prior year-end.

In 2005, crude oil and NGLs reserves increased significantly, largely as a result of 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.

In keeping with U.S. standards requiring 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 that the estimate is made), reference year-end 2006 prices were as follows: crude oil (WTI) \$60.85/bbl, (Edmonton Light) C\$67.58/bbl, both essentially unchanged from year-end 2005; Foster Creek field price C\$35.10/bbl, an increase of 91 percent from year-end 2005; natural gas (Henry Hub) \$5.64/MMbtu, a decrease of 45 percent from year-end 2005; and natural gas (AECO) C\$6.07/MMbtu, a decrease of 37 percent from year-end 2005.

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 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above.

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	Total	Canada	United States	Ecuador	United Kingdom	Total
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 due to bitumen price	—	—	—	—	362.7[4]	—	—	—	362.7
Beginning of year before bitumen revisions	5,824	4,636	—	10,460	629.6	91.0	143.3	—	863.9
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)
End of year	6,517	5,267	—	11,784	932.5	53.1	135.0[5]	—	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
2006									
Beginning of year	6,517	5,267	—	11,784	932.5	53.1	135.0	—	1,120.6
Revisions and improved recovery	301	(88)	—	213	(39.0)	(1.1)	—	—	(40.1)
Extensions and discoveries	1,014	606	—	1,620	238.7	6.4	—	—	245.1
Purchase of reserves in place	—	68	—	68	—	0.3	—	—	0.3
Sale of reserves in place	(6)	(32)	—	(38)	(0.1)	—	(130.6)	—	(130.7)
Production	(798)	(431)	—	(1,229)	(52.7)	(4.7)	(4.4)	—	(61.8)
End of year	7,028	5,390	—	12,418	1,079.4[6]	54.0	—	—	1,133.4
Developed	4,718	2,964	—	7,682	316.9	33.5	—	—	350.4
Undeveloped	2,310	2,426	—	4,736	762.5	20.5	—	—	783.0
Total	7,028	5,390	—	12,418	1,079.4[6]	54.0	—	—	1,133.4

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.

(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) The Corporation divested its Ecuadorian operations in 2006.

(6) Proved crude oil and NGLs reserves at December 31, 2006 include approximately 800 million barrels of bitumen, of which 796 million barrels was attributable to the Corporation's interests in Foster Creek and Christina Lake on that date. Effective January 2, 2007, these interests were contributed to the Upstream Partnership in which the Corporation has a 50 percent interest. Accordingly, effective as at that date, the Corporation's reserves associated with those properties were reduced by 398 million barrels.

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 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 Market Optimization interests.

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

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Future cash inflows	72,262	71,786	37,791	27,165	40,504	27,063	—	5,350	3,317
Less future:									
Production costs	20,471	16,765	7,760	4,123	3,262	2,462	—	2,093	1,136
Development costs	9,355	6,164	3,157	4,715	4,174	3,213	—	429	198
Asset retirement obligation payments	2,397	2,269	1,749	396	264	193	—	24	22
Income taxes	8,816	13,170	6,279	5,349	11,041	7,021	—	662	342
Future net cash flows	31,223	33,418	18,846	12,582	21,763	14,174	—	2,142	1,619
Less 10% annual discount for estimated timing of cash flows	14,627	13,281	6,668	6,128	10,291	6,686	—	574	417
Discounted future net cash flows	16,596	20,137	12,178	6,454	11,472	7,488	—	1,568	1,202

	United Kingdom			Total		
	2006	2005	2004	2006	2005	2004
				($ millions)		
Future cash inflows	—	—	—	99,427	117,640	68,171
Less future:						
Production costs	—	—	—	24,594	22,120	11,358
Development costs	—	—	—	14,070	10,767	6,568
Asset retirement obligation payments	—	—	—	2,793	2,557	1,964
Income taxes	—	—	—	14,165	24,873	13,642
Future net cash flows	—	—	—	43,805	57,323	34,639
Less 10% annual discount for estimated timing of cash flows	—	—	—	20,755	24,146	13,771
Discounted future net cash flows	—	—	—	23,050	33,177	20,868

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

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
	($ millions)								
Balance, beginning of year	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367
Changes resulting from:									
Sales of oil and gas produced during the period	(5,970)	(5,720)	(3,965)	(2,373)	(2,436)	(1,474)	(142)	(604)	(264)
Discoveries and extensions, net of related costs	2,584	4,278	3,562	877	3,582	2,436	—	159	236
Purchases of proved reserves in place	—	26	531	69	237	2,786	—	—	—
Sales of proved reserves in place	(19)	(279)	(1,579)	(85)	(486)	(271)	(1,359)	—	—
Net change in prices and production costs	(5,797)	11,624	2,264	(7,636)	4,716	143	—	967	(294)
Revisions to quantity estimates	155	1,071	546	265	(700)	(542)	—	88	(125)
Accretion of discount	2,809	1,629	1,349	1,714	1,103	725	—	147	176
Previously estimated development costs incurred net of change in future development costs	(805)	(888)	57	(350)	162	22	(46)	(148)	15
Other	(174)	63	32	(381)	(64)	(49)	—	8	(29)
Net change in income taxes	3,676	(3,845)	(634)	2,882	(2,130)	(1,176)	(21)	(251)	120
Balance, end of year	16,596	20,137	12,178	6,454	11,472	7,488	—	1,568	1,202

	United Kingdom			Total		
	2006	2005	2004	2006	2005	2004
	($ millions)					
Balance, beginning of year	—	—	565	33,177	20,868	16,835
Changes resulting from:						
Sales of oil and gas produced during the period	—	—	(78)	(8,485)	(8,760)	(5,781)
Discoveries and extensions, net of related costs	—	—	—	3,461	8,019	6,234
Purchases of proved reserves in place	—	—	77	69	263	3,394
Sales of proved reserves in place	—	—	(899)	(1,463)	(765)	(2,749)
Net change in prices and production costs	—	—	—	(13,433)	17,307	2,113
Revisions to quantity estimates	—	—	—	420	459	(121)
Accretion of discount	—	—	82	4,523	2,879	2,332
Previously estimated development costs incurred net of change in future development costs	—	—	—	(1,201)	(874)	94
Other	—	—	—	(555)	7	(46)
Net change in income taxes	—	—	253	6,537	(6,226)	(1,437)
Balance, end of year	—	—	—	23,050	33,177	20,868

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador[1]		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Oil and gas revenues, net of royalties, transportation and selling costs	7,190	6,701	4,787	3,096	3,052	1,861	190	873	451
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,220	981	822	723	616	387	48	269	187
Depreciation, depletion and amortization	2,146	1,961	1,752	869	712	487	84	234	263
Operating income (loss)	3,824	3,759	2,213	1,504	1,724	987	58	370	1
Income taxes	1,235	1,274	841	556	638	375	21	134	5
Results of operations	2,589	2,485	1,372	948	1,086	612	37	236	(4)

	United Kingdom			Other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Oil and gas revenues, net of royalties, transportation and selling costs	—	—	117	2	—	—	10,478	10,626	7,216
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	—	—	39	11	6	4	2,002	1,872	1,439
Depreciation, depletion and amortization	—	—	118	10	8	25	3,109	2,915	2,645
Operating income (loss)	—	—	(40)	(19)	(14)	(29)	5,367	5,839	3,132
Income taxes	—	—	(15)	—	—	—	1,812	2,046	1,206
Results of operations	—	—	(25)	(19)	(14)	(29)	3,555	3,793	1,926

Note:

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 and 2005 represents provisions which have been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments at February 28, 2006 and December 31, 2005.

Capitalized Costs

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Proved oil and gas properties	31,546	27,074	22,455	9,796	7,753	7,552	—	1,926	1,784
Unproved oil and gas properties	1,700	1,998	1,855	1,221	870	728	—	18	45
Total capital cost	33,246	29,072	24,310	11,017	8,623	8,280	—	1,944	1,829
Accumulated DD&A	14,261	12,131	9,770	2,595	1,750	1,046	—	778	534
Net capitalized costs	18,985	16,941	14,540	8,422	6,873	7,234	—	1,166	1,295

	United Kingdom			Other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Proved oil and gas properties	—	—	—	—	—	—	41,342	36,753	31,791
Unproved oil and gas properties	—	—	—	361	470	425	3,282	3,356	3,053
Total capital cost	—	—	—	361	470	425	44,624	40,109	34,844
Accumulated DD&A	—	—	—	98	222	247	16,954	14,881	11,597
Net capitalized costs	—	—	—	263	248	178	27,670	25,228	23,247

Costs Incurred

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
	($ millions)								
Acquisitions									
— Unproved reserves	—	—	42	278	271	954	—	—	—
— Proved reserves	47	30	204	6	141	2,051	—	—	—
Total acquisitions	47	30	246	284	412	3,005	—	—	—
Exploration costs	403	817	555	236	264	164	1	15	28
Development costs	3,611	3,333	2,669	1,826	1,724	1,103	46	164	213
Total costs incurred	4,061	4,180	3,470	2,346	2,400	4,272	47	179	241

	United Kingdom			Other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
	($ millions)								
Acquisitions									
— Unproved reserves	—	—	—	—	—	—	278	271	996
— Proved reserves	—	—	130	—	—	—	53	171	2,385
Total acquisitions	—	—	130	—	—	—	331	442	3,381
Exploration costs	—	—	22	75	70	79	715	1,166	848
Development costs	—	—	364	—	—	—	5,483	5,221	4,349
Total costs incurred	—	—	516	75	70	79	6,529	6,829	8,578

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 — 2006				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,185	2,205	2,162	2,192	2,182
Inventory withdrawal/(injection)	—	—	—	—	—
Canada Sales	2,185	2,205	2,162	2,192	2,182
United States	1,182	1,201	1,197	1,169	1,161
Total Produced Gas	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	44,360	41,872	45,980	43,727	45,889
Heavy Oil — Foster Creek/Christina Lake	42,768	46,678	43,073	39,215	42,050
Heavy Oil — Other	43,369	39,498	37,605	46,128	50,431
Natural Gas Liquids[1]					
Canada	11,713	11,856	11,387	11,607	12,006
United States	12,494	12,250	12,520	12,793	12,415
Total Oil and Natural Gas Liquids	154,704	152,154	150,565	153,470	162,791
Total Continuing Operations ***(MMcfe/d)***	4,295	4,319	4,262	4,282	4,320
Discontinued Operations:					
Ecuador					
Production	11,996	—	—	—	48,650
(Under)/over lifting	370	—	—	—	1,500
Ecuador Sales *(bbls/d)*	12,366	—	—	—	50,150
Total Discontinued Operations ***(MMcfe/d)***	74	—	—	—	301
Total ***(MMcfe/d)***	4,369	4,319	4,262	4,282	4,621

Note:

(1) Natural gas liquids include condensate volumes.

	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 — Foster Creek/Christina Lake	34,379	39,839	32,580	31,025	34,027
Heavy Oil — Other	48,711	48,547	48,509	51,249	46,519
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	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

Note:

(1) Natural gas liquids include condensate volumes.

	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 withdrawal/(injection)	(6)	(26)	—	—	—
Canada Sales[1]	2,099	2,080	2,138	2,177	2,000
United States	869	1,007	958	824	684
Total Produced Gas	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	56,215	52,725	52,824	64,448	54,940
Heavy Oil — Foster Creek/Christina Lake	33,105	33,035	34,384	33,624	31,353
Heavy Oil — Other	51,059	46,301	55,298	46,275	56,376
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	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 divestitures total approximately 42 MMcf/day for the full year 2004.

(2) Natural gas liquids include condensate volumes.

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

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.

	2006					2005					2004				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	10.5	9.9	10.5	10.4	11.2	11.7	11.9	11.8	11.0	11.9	12.5	12.0	12.2	12.7	13.3
United States	18.5	18.3	18.4	18.7	18.7	18.6	18.6	19.9	17.9	18.1	19.6	19.8	18.3	21.1	19.3
Crude Oil															
Canada and United States	9.9	10.3	11.4	10.5	7.5	8.8	8.8	8.7	9.2	8.7	9.0	8.7	8.8	11.6	9.4
Natural Gas Liquids															
Canada	15.5	15.3	16.3	14.4	16.1	14.9	14.4	15.8	15.6	13.8	15.7	16.5	18.5	13.1	14.8
United States	18.7	18.8	17.7	20.1	18.3	18.2	19.4	20.1	12.7	20.0	18.7	21.4	13.6	20.7	19.2
Total North America	13.0	12.7	13.2	13.1	12.9	13.3	13.5	13.8	12.6	13.3	13.7	13.8	13.2	14.1	13.7
Discontinued Operations:															
Crude Oil — Ecuador	25.2	—	—	—	25.2	27.2	29.4	26.3	26.3	26.9	27.1	27.8	26.5	26.5	27.4

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 — 2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	0.10	0.05	0.09	0.08	0.18
Transportation and selling	0.35	0.33	0.37	0.35	0.34
Operating	0.79	0.82	0.78	0.77	0.79
Netback	4.96	4.67	4.35	4.51	6.35
Produced Gas — United States ($/Mcf)					
Price	6.35	5.65	6.04	6.08	7.70
Production and mineral taxes	0.49	0.50	0.43	0.22	0.85
Transportation and selling	0.54	0.60	0.57	0.50	0.49
Operating	0.65	0.68	0.59	0.70	0.64
Netback	4.67	3.87	4.45	4.66	5.72
Produced Gas — Total North America ($/Mcf)					
Price	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	0.24	0.21	0.21	0.13	0.41
Transportation and selling	0.42	0.42	0.44	0.40	0.40
Operating	0.74	0.77	0.71	0.74	0.74
Netback	4.85	4.39	4.39	4.57	6.13

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — Canada ($/bbl)					
Price	51.12	44.79	55.95	55.19	48.84
Production and mineral taxes	—	—	—	—	—
Transportation and selling	0.67	0.58	0.74	0.73	0.61
Netback	50.45	44.21	55.21	54.46	48.23
Natural Gas Liquids — United States ($/bbl)					
Price	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	4.19	4.62	4.42	2.60	5.18
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids — Total North America ($/bbl)					
Price	53.81	47.97	58.99	56.80	51.50
Production and mineral taxes	2.16	2.35	2.31	1.36	2.63
Transportation and selling	0.33	0.29	0.36	0.35	0.31
Netback	51.32	45.33	56.32	55.09	48.56
Crude Oil — Light and Medium — North America ($/bbl)					
Price	51.76	43.28	56.50	61.62	45.31
Production and mineral taxes	2.16	2.15	2.13	2.47	1.92
Transportation and selling	0.98	0.61	1.32	0.65	1.29
Operating	8.62	9.01	10.00	7.36	8.06
Netback	40.00	31.51	43.05	51.14	34.04
Crude Oil — Heavy — Foster Creek/Christina Lake ($/bbl)					
Price	36.49	39.32	37.19	46.53	23.08
Production and mineral taxes	—	—	—	—	—
Transportation and selling	2.64	2.74	2.64	3.38	1.80
Operating(1)	12.38	13.07	14.06	11.78	10.39
Netback	21.47	23.51	20.49	31.37	10.89
Crude Oil — Total Heavy — North America ($/bbl)					
Price	36.72	33.87	44.32	46.49	23.53
Production and mineral taxes	0.05	0.05	0.05	0.07	0.04
Transportation and selling	1.62	1.35	1.98	2.00	1.21
Operating	9.33	10.58	10.32	8.82	7.69
Netback	25.72	21.89	31.97	35.60	14.59
Crude Oil — Total North America ($/bbl)					
Price	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	0.77	0.74	0.81	0.88	0.66
Transportation and selling	1.40	1.11	1.74	1.54	1.24
Operating	9.09	10.05	10.20	8.34	7.82
Netback	30.57	25.04	35.99	40.86	21.04
Total Liquids — Canada ($/bbl)					
Price	42.53	37.55	49.21	51.91	32.17
Production and mineral taxes	0.70	0.67	0.73	0.80	0.61
Transportation and selling	1.35	1.06	1.67	1.48	1.19
Operating	8.33	9.21	9.39	7.63	7.17
Netback	32.15	26.61	37.42	42.00	23.20

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Total Liquids — Total North America ($/bbl)					
Price	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	0.99	0.99	1.05	0.96	0.96
Transportation and selling	1.24	0.98	1.52	1.35	1.10
Operating	7.66	8.47	8.58	7.01	6.64
Netback	33.82	28.25	39.22	43.12	25.17
Total North America ($/Mcfe)					
Price	6.48	5.93	6.31	6.46	7.22
Production and mineral taxes	0.22	0.20	0.20	0.13	0.36
Transportation and selling	0.37	0.37	0.40	0.36	0.35
Operating(2)	0.86	0.90	0.87	0.84	0.82
Netback	5.03	4.46	4.84	5.13	5.69
Discontinued Operations:					
Crude Oil — Ecuador ($/bbl)					
Price	44.35	—	—	—	44.35
Production and mineral taxes	5.03	—	—	—	5.03
Transportation and selling	2.25	—	—	—	2.25
Operating	5.55	—	—	—	5.55
Netback	31.52	—	—	—	31.52

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

(2) Year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe.

	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
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 — Foster Creek/Christina Lake ($/bbl)					
Price	22.02	20.17	33.11	19.28	15.92
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.54	1.53	1.24	2.02	1.42
Operating(1)	10.94	11.93	10.74	11.71	9.25
Netback	9.54	6.71	21.13	5.55	5.25
Crude Oil — Heavy — North America ($/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	7.74	8.50	7.95	7.43	6.97
Netback	18.94	18.61	30.62	14.19	12.24
Crude Oil — Total North America ($/bbl)					
Price	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	0.58	0.66	0.48	0.66	0.53
Transportation and selling	1.20	1.12	1.15	1.15	1.39
Operating	7.23	7.79	7.35	7.02	6.74
Netback	25.14	24.84	36.18	21.00	18.94
Total Liquids — Canada ($/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	6.61	7.13	6.66	6.45	6.19
Netback	26.69	26.85	37.17	22.43	20.62

	Per-Unit Results — 2005				
	Year	Q4	Q3	Q2	Q1
Total Liquids — Total North America ($/bbl)					
Price	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	0.91	0.99	0.91	0.92	0.83
Transportation and selling	1.04	0.98	0.99	1.00	1.18
Operating	6.04	6.56	6.08	5.91	5.61
Netback	28.18	28.63	38.18	23.97	22.15
Total North America ($/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(2)	0.71	0.77	0.72	0.67	0.66
Netback	5.77	7.85	6.02	4.78	4.36
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

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

(2) 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
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 — Foster Creek/Christina Lake ($/bbl)					
Price	20.75	17.46	26.32	19.92	18.97
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.15	1.03	1.26	1.15	1.15
Operating(1)	9.34	10.41	9.03	8.97	8.96
Netback	10.26	6.02	16.03	9.80	8.86
Crude Oil — Total Heavy — North America ($/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	6.10	7.24	5.39	5.77	6.11
Netback	16.18	14.66	20.94	15.09	13.62
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	6.00	6.91	5.80	5.36	6.02
Netback	20.45	21.08	23.93	19.97	16.84

	Per-Unit Results — 2004				
	Year	Q4	Q3	Q2	Q1
Total Liquids — Canada ($/bbl)					
Price	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	0.37	0.52	0.31	0.32	0.34
Transportation and selling	1.00	0.11	1.35	1.10	1.40
Operating	5.48	6.28	5.33	4.90	5.48
Netback	21.36	22.45	24.64	20.67	17.73
Total Liquids — Total North America ($/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	5.06	5.72	4.87	4.53	5.17
Netback	22.15	23.56	25.30	21.29	18.41
Total North America ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating(2)	0.57	0.61	0.54	0.54	0.60
Netback	4.21	4.70	4.17	4.09	3.85
Discontinued Operations:					
Crude Oil — Ecuador ($/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

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

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

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

	2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	0.47	0.91	0.82	0.66	(0.53)
Liquids ($/bbl)	(3.32)	(3.30)	(3.45)	(3.43)	(3.12)
Total ($/Mcfe)	0.25	0.60	0.53	0.40	(0.53)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(0.12)	—	—	—	(0.12)

	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)

Note:

(1) Excludes hedges unwound as a result of the United Kingdom divestiture.

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:											
2006:											
Canada	281	230	7	7	7	6	295	243	128	423	243
United States	12	7	—	—	2	1	14	8	—	14	8
Other	—	—	2	1	4	1	6	2	—	6	2
Total	293	237	9	8	13	8	315	253	128	443	253
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
Discontinued Operations:											
Ecuador — 2006	—	—	—	—	—	—	—	—	—	—	—
Ecuador — 2005	—	—	2	1	3	2	5	3	—	5	3
Ecuador — 2004	—	—	6	3	—	—	6	3	—	6	3
United Kingdom — 2004	—	—	1	—	4	2	5	2	—	5	2

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:											
2006:											
Canada	2,799	2,639	139	103	25	24	2,963	2,766	855	3,818	2,766
United States	779	625	—	—	7	6	786	631	22	808	631
Total	3,578	3,264	139	103	32	30	3,749	3,397	877	4,626	3,397
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
Discontinued Operations:											
Ecuador — 2006	—	—	7	6	1	1	8	7	—	8	7
Ecuador — 2005	—	—	28	15	3	1	31	16	—	31	16
Ecuador — 2004	—	—	43	25	1	1	44	26	—	44	26
United Kingdom — 2004	—	—	3	1	—	—	3	1	—	3	1

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, 2006, EnCana was in the process of drilling 34 gross wells (32 net wells) in Canada, 46 gross wells (34 net wells) in the United States and one well outside of North America.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2006:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	35,826	33,764	3,956	3,593	39,782	37,357
British Columbia	1,950	1,758	16	10	1,966	1,768
Saskatchewan	477	451	1,244	544	1,721	995
Manitoba	—	—	1	1	1	1
Total Canada	38,253	35,973	5,217	4,148	43,470	40,121
Colorado	4,119	3,583	—	—	4,119	3,583
Texas	3,101	1,427	39	21	3,140	1,448
Wyoming	1,756	1,210	1	—	1,757	1,210
Utah	20	15	2	2	22	17
Oklahoma	1	—	—	—	1	—
Total United States	8,997	6,235	42	23	9,039	6,258
Total	47,250	42,208	5,259	4,171	52,509	46,379

Notes:

(1) EnCana has varying royalty interests in 14,554 natural gas wells and 9,155 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 28,296 gross natural gas wells (26,945 net wells) and 1,314 gross crude oil wells (1,130 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2006:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	— Fee	4,415	4,415	2,708	2,707	7,123	7,122
	— Crown	4,051	3,200	5,259	4,368	9,310	7,568
	— Freehold	230	132	212	175	442	307
		8,696	7,747	8,179	7,250	16,875	14,997
British Columbia	— Crown	1,053	900	4,353	3,653	5,406	4,553
	— Freehold	—	—	7	—	7	—
		1,053	900	4,360	3,653	5,413	4,553
Saskatchewan	— Fee	62	62	457	457	519	519
	— Crown	133	114	508	461	641	575
	— Freehold	15	11	51	48	66	59
		210	187	1,016	966	1,226	1,153
Manitoba	— Fee	3	3	263	263	266	266
		3	3	263	263	266	266
Newfoundland & Labrador	— Crown	—	—	1,550	1,018	1,550	1,018
Nova Scotia	— Crown	—	—	1,184	638	1,184	638
Northwest Territories	— Crown	—	—	314	174	314	174
Yukon	— Crown	—	—	5	2	5	2
Beaufort	— Crown	—	—	125	4	125	4
Total Canada		9,962	8,837	16,996	13,968	26,958	22,805

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	— Federal/State Lands	191	178	798	732	989	910
	— Freehold	110	104	161	147	271	251
	— Fee	3	3	37	37	40	40
		304	285	996	916	1,300	1,201
Washington	— Federal/State Lands	—	—	638	626	638	626
	— Freehold	—	—	185	185	185	185
		—	—	823	811	823	811
Texas	— Federal/State Lands	8	3	441	423	449	426
	— Freehold	172	113	1,216	988	1,388	1,101
	— Fee	—	—	4	2	4	2
		180	116	1,661	1,413	1,841	1,529
Wyoming	— Federal/State Lands	143	87	785	593	928	680
	— Freehold	25	18	57	35	82	53
		168	105	842	628	1,010	733
Other	— Federal/State Lands	9	7	336	199	345	206
	— Freehold	12	5	1,031	1,026	1,043	1,031
		21	12	1,367	1,225	1,388	1,237
Total United States		673	518	5,689	4,993	6,362	5,511
Chad(7)		—	—	54,103	27,052	54,103	27,052
Oman		—	—	8,568	4,284	8,568	4,284
Qatar		—	—	2,160	1,081	2,160	1,081
Greenland		—	—	1,701	1,488	1,701	1,488
Brazil		—	—	1,662	522	1,662	522
Australia		—	—	1,053	357	1,053	357
France		—	—	859	859	859	859
Azerbaijan		—	—	346	17	346	17
Total International		—	—	70,452	35,660	70,452	35,660
Total		10,635	9,355	93,137	54,621	103,772	63,976

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. 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.

(7) In January 2007, a subsidiary of EnCana completed the sale of all its interests in its Chad exploration assets.

Acquisitions, Divestitures 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 select acquisition opportunities to develop and expand its key resource plays. The acquisition opportunities may include corporate or asset acquisitions, and EnCana may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset divestitures or a combination of these sources.

The following table summarizes EnCana's net capital investment for 2006 and 2005.

	2006	2005
	($ millions)	
Upstream		
Canada — excluding Foster Creek / Christina Lake	3,383	3,757
Foster Creek / Christina Lake	632	393
Total Canada	4,015	4,150
United States	2,061	1,982
Other Countries	75	70
	6,151	6,202
Market Optimization	44	197
Corporate	74	78
Core Capital from Continuing Operations	6,269	6,477
Upstream		
Acquisitions		
Property		
Canada	47	30
United States(1)	284	418
Divestitures		
Property		
Canada	(59)	(447)
United States	(19)	(2,074)
Corporate(2)	(367)	—
Market Optimization		
Corporate(3)	(244)	—
Corporate	—	(2)
Net Acquisition and Divestiture Activity from Continuing Operations	(358)	(2,075)
Discontinued Operations		
Ecuador(4)	(1,116)	179
Midstream(5)	(1,531)	(484)
Net Capital Investment	3,264	4,097

Notes:

(1) The Corporation acquired additional operated interest in East Texas on June 29, 2006.

(2) The sale of shares of EnCanBrasil Limitada was completed on August 16, 2006.

(3) The sale of shares of Entrega Gas Pipeline LLC was completed on February 23, 2006.

(4) The sale of all of the Corporation's Ecuador interests was completed on February 28, 2006.

(5) The sale of Phase 1 of EnCana's Gas Storage interests was completed on May 12, 2006, followed by Phase 2 which was completed on November 17, 2006.

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, 2006.

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) reserves and property acquisitions; (iii) transportation and marketing of oil, natural gas, NGLs, diluents and electricity; (iv) supply of refinery feedstock and the market for refined products (v) access to services and equipment to carry out exploration, development or operating activities; and (vi) 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 2006, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2007. 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 approximately $5.3 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. 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, and 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, 2006, EnCana employed 4,678 full time equivalent ("FTE") employees as set forth in the following table:

	FTE Employees
Upstream	3,337
Midstream & Marketing	615
Corporate	726
Total	4,678

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

Foreign Operations

As at December 31, 2006, 100 percent of EnCana's reserves and 100 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 divestitures. Between December 2005 and February 2006, the Corporation completed a restructuring of various Canadian subsidiaries in order to eliminate corporate entities that had become unnecessary.

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 Partners 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 producer)*

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)*
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[1,5] . . . . 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)* Chairman OPTI Canada Inc. *(Oilsands company)*

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 14 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 13 nominees listed in the above table (with the exception of Mr. Michael N. Chernoff who will be retiring) and two new nominees, Mr. Allan P. Sawin and Mr. Wayne G. Thomson, 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, whereby a director may not stand for re-election at the first annual meeting after reaching the age of 71, all of the directors shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	Corporate Office (Divisional Title)
DAVID P. O'BRIEN Calgary, Alberta, Canada	Chairman
RANDALL K. ERESMAN Calgary, Alberta, Canada	President & Chief Executive Officer
JOHN K. BRANNAN(1) Calgary, Alberta, Canada	Executive Vice-President *(President, Integrated Oilsands Division)*
SHERRI A. BRILLON(2) Calgary, Alberta, Canada	Executive Vice-President, Strategic Planning & Portfolio Management
BRIAN C. FERGUSON Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
MICHAEL M. GRAHAM Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Foothills Division)*
SHEILA M. MCINTOSH(3) Calgary, Alberta, Canada	Executive Vice-President, Corporate Communications
R. WILLIAM OLIVER(4) Calgary, Alberta, Canada	Executive Vice-President, Business Development *(President, Midstream & Marketing Division)*
GERARD J. PROTTI(5) Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations *(President, Offshore & International Division)*
DONALD T. SWYSTUN(6) Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Plains Division)*
HAYWARD J. WALLS Calgary, Alberta, Canada	Executive Vice-President, Corporate Services
JEFF E. WOJAHN Denver, Colorado, USA	Executive Vice-President *(President, USA Division)*

Notes:

(1) John K. Brannan (formerly Managing Director, FINV) was appointed Executive Vice-President of EnCana and President, Integrated Oilsands Division effective January 1, 2007.

(2) Sherri A. Brillon (formerly Vice-President, Strategic Planning & Portfolio Management) was appointed Executive Vice-President, Strategic Planning & Portfolio Management of EnCana effective January 1, 2007.

(3) Sheila M. McIntosh (formerly Vice-President, Investor Relations) was appointed Executive Vice-President, Corporate Communications of EnCana effective January 1, 2007.

(4) R. William Oliver (formerly Executive Vice-President of EnCana and President Midstream & Marketing) was appointed Executive Vice-President, Business Development of EnCana effective January 1, 2007 and remains President, Midstream & Marketing Division.

(5) Gerard J. Protti (Executive Vice-President, Corporate Development) was, in addition to his current position, appointed President, Offshore & International Division effective January 1, 2007.

(6) Donald T. Swystun (formerly Executive Vice-President, Corporate Development) was appointed Executive Vice-President of EnCana and President, Canadian Plains Division, effective January 1, 2007.

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 Partners 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. Prior to March 2005, he was a Corporate Director.

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. Sawin is being nominated for election as a director of the Corporation at the next Annual Meeting of Shareholders. Mr. Sawin is President of Bear Investments Inc., a private investment company. From 1990 until their sale to CCS Income Trust in May 2006, he was President, director and part owner of Grizzly Well Servicing Inc. and related companies. He is also a director of a number of private companies.

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

Mr. Thomson is being nominated for election as a director of the Corporation at the next Annual Meeting of Shareholders. Since February 2005, Mr. Thomson has been President and a director of Virgin Resources Limited, a private junior international oil and gas exploration company, with activities focused in Yemen. He is a director of TG World Energy Corp. (TSX Venture listed international oil and gas exploration company) and a director of EcoMax Energy Services Ltd. (TSX Venture listed oil and gas service company). He is also a director of several private companies. Mr. Thomson was President and a director of Airborne Pollution Control from 2001 to 2003. Prior to 2001, he served as President and a director of private companies in the oil and gas sector, namely, Hadrian Energy Corp., Gardiner Exploration Limited and Petrocorp Exploration Limited (New Zealand oil and gas company), a division of Fletcher Challenge (public company), and was also President of Gardiner Oil and Gas Limited while it was a public company listed on the Toronto Stock Exchange.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 14, 2007, directly or indirectly, or exercised control or direction over an aggregate of 2,275,823 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 3,590,778 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. He is also a director and past member of the Audit Committee of Enerflex Systems Ltd. (compression systems manufacturer) and a director and Chair of the Finance Committee of Synenco Energy Inc. (oilsands mining).

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). He is also a director and Chairman (as well as past 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, headquartered in California. 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). He is a director and Chairman of OPTI Canada Inc. (oilsands development and upgrading company). He is also a director of Kinder Morgan, Inc. (North American midstream energy 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 a director, President and Chief Executive Officer of Petro-Canada (oil and gas company) from 1993 until his retirement in 2000. He also served as the President, Chief Operating Officer and a director of Petro-Canada from 1990 to 1993.

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 2006 and 2005:

($ thousands)	2006	2005
Audit Fees(1)	3,762	3,726
Audit-Related Fees(2)	401	894
Tax Fees(3)	1,215	1,021
All Other Fees(4)	34	26
Total	5,412	5,667

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 2006 and 2005, the services provided in this category included due diligence reviews in connection with acquisitions and divestitures, research of accounting and audit-related issues and review of reserves disclosure.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2006 and 2005, 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 2006 and 2005, 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 2005 or 2006.

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, 2006 there were approximately 784 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. It is anticipated that the Plan will be presented to shareholders for reconfirmation at the 2007 annual and special meeting of shareholders.

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, 2006.

	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	Positive	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 within the third highest of ten categories and indicates that the obligor has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher rated categories. 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 within 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. The addition a ratings outlook of "Positive (POS)", "Negative (NEG)" or "Stable (STA)"is an opinion regarding the likely direction of a rating over the medium term. 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 within 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 2006.

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	(C$ per share)			(millions)	($ per share)			(millions)
2006								
January	57.10	51.70	56.75	90.0	49.93	44.68	49.86	83.2
February	57.08	44.96	47.00	88.0	50.05	39.54	41.31	90.8
March	57.00	46.55	54.50	95.2	49.04	40.92	46.73	84.4
April	59.25	53.45	55.88	57.6	52.33	46.54	50.05	59.0
May	59.20	49.51	55.56	61.2	53.70	44.02	50.54	72.3
June	59.38	49.91	58.78	65.5	53.31	45.15	52.64	76.4
July	62.52	53.61	61.04	48.6	55.43	46.88	54.06	53.8
August	62.49	58.00	58.00	46.0	55.93	52.24	52.74	50.1
September	59.51	48.35	52.01	65.5	53.68	43.32	46.69	63.4
October	55.47	48.28	53.33	72.0	49.20	42.75	47.49	74.5
November	61.00	51.83	59.36	58.2	53.44	45.77	52.21	61.4
December	61.90	53.55	53.66	58.7	53.90	45.95	45.95	61.5

In November 2006, EnCana received approval from the TSX to renew its normal course issuer bid. Under the renewed program, EnCana is entitled to purchase up to 10 percent of its outstanding common shares. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange.

During January 2007, EnCana purchased 10.8 million shares under the program for approximately $494 million.

In 2006, EnCana purchased 85.6 million shares under the program for an average price of $49.26 for approximately $4.2 billion.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2004, cash dividends were paid to common shareholders 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). In the second quarter of 2006, EnCana increased its dividend by 33 percent to $0.40 per share ($0.10 per share quarterly). EnCana's Board of Directors has declared a dividend of $0.20 per share payable on March 30, 2007 to common shareholders of record on March 15, 2007, a 100 percent increase over the previous dividend. 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 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 reserves base and acquiring, discovering or developing additional reserves. Without reserves 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 reserves 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 reserves 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. Under Canadian GAAP, derivative instruments that do not qualify as hedges, or are not designated as hedges, are marked-to-market with changes in fair value recognized in current period net earnings. The utilization of derivative financial instruments may therefore introduce significant volatility into the Corporation's reported net earnings.

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 undertakes a variety of projects including exploration and development projects and the construction or expansion of facilities, refineries 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 availability of diluents to transport crude oil;
- the ability to access lands;
- weather;
- unexpected cost increases;
- accidents;
- general business and market conditions;
- the availability of skilled labour; and
- environmental and regulatory matters.

All of EnCana's operations are 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, natural gas and refining businesses 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 Canadian Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. The Government is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce GHG emissions by 45 percent to 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short-term. Currently there are few technical details regarding the implementation of the Government's plan to regulate industrial GHG emissions, but the Government has made a commitment to work with industry to develop the specifics.

As this federal program is under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Corporation could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana in cooperation with the Canadian Association of Petroleum Producers will continue to work with the Government to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana will continue its current activities to reduce emissions intensity and improve energy efficiency. The Corporation's efforts with respect to emissions management are founded on the following key elements:

- significant weighting in natural gas;
- recognition as an industry leader in CO_2 sequestration;
- focus on the development of technology to reduce GHG emissions;
- involvement in the creation of industry best practices; and
- industry leading oilsands steam to oil ratio, which translates directly into a lower emissions intensity.

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 and refining 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, refining 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, natural gas and refined products 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 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 assets, 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.

All of the Corporation's downstream operations are operated by ConocoPhillips. The success of the Corporation's downstream operations is dependant on the ability of ConocoPhillips to successfully operate this business.

The volatility of downstream margins will have an impact on EnCana's results.

EnCana's downstream operations are sensitive to margins for refined products. Margin volatility is impacted by numerous conditions including: market competitiveness, the cost of crude oil, fluctuations in the supply and demand for refined products and weather. It is expected that all of these and other factors will continue to impact downstream margins for the foreseeable future. As a result, it can be reasonably expected that downstream results will fluctuate over time and from period to period.

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 SAGD 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.

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payments of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

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, or whether there will be other proceedings arising out of these allegations.

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, 2006. 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 23, 2007 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, 2006.

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, 2006. The reserves data consist of the following:

   (i) estimated proved oil and gas reserves quantities as at December 31, 2006 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 reserves 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 reserves 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, 2006:

		Estimated Proved Reserves Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax, 10% discount rate
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	
		(Bcf)	(MMbbl)	(US$MM)
McDaniel & Associates Consultants Ltd. January 25, 2007	Canada	4,280	983	13,674
GLJ Petroleum Consultants Ltd. January 18, 2007	Canada	2,748	96	6,627
Netherland, Sewell & Associates, Inc. January 18, 2007	United States	4,230	50	6,833
DeGolyer and MacNaughton January 18, 2007	United States	1,160	4	1,692
Totals		12,418	1,133	28,826

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, 2007

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 reserves quantities estimated as at December 31, 2006 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 reserves quantities.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators dated February 13, 2007 (the "IQRE Report"), highlighting the standards they followed and their results, accompanies this Report.

The Reserves Committee of 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 of the Corporation (the "Board of Directors") has reviewed the standardized measure calculation with respect to the Corporation's proved oil and gas reserves 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 reserves 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) Donald T. Swystun
Executive Vice-President

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

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

February 14, 2007

APPENDIX C

Audit Committee Mandate

Last Updated December 13, 2006

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 unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting 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.

The items pertaining to the Chairman in this section should be read in conjunction with the Committee Chair section of the *Chair of the Board of Directors and Committee Chair General Guidelines*.

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, or in writing, or by facsimile, or by electronic means 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 proved reserves have been reviewed with the Reserves Committee of the Board.
15. Review 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.