ENCANA™

ANNUAL INFORMATION FORM

February 22, 2008

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2007. 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. reporting protocol.

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: bitumen strategy and the benefits of this strategy, 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 anticipated date of production for the Deep Panuke natural gas project, the timing of completion of the Foster Creek and Christina Lake expansions, including the timing for receipt of regulatory approvals and well testing, the anticipated capacities of and the timing of capacity expansions for the Wood River and Borger refineries, anticipated capacity expansion of the Steeprock natural gas plant, 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, anticipated post-closing adjustments and indemnities and future 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 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 royalty, tax, environmental and other laws or regulations or the interpretations of such laws or 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. 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. This facilitates comparability of oil and gas disclosure with that provided by U.S. and other international issuers, given that EnCana is active in the U.S. capital markets. 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 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, 2007. 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, 2007.

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 (USA) Investment Holdings	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Marketing (USA) Inc.	100	Delaware
EnCana Oil & Gas Co. Ltd.	100	Alberta
1140102 Alberta Ltd.	100	Alberta
FCCL Oil Sands Partnership	50	Alberta
EnCana Downstream Holdings LLC	100	Delaware
EnCana US Refinery Holdings	100	Delaware
WRB Refining LLC	50	Delaware

Note:

(1) Includes indirect ownership.

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, 2007.

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 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. All of EnCana's proved reserves and production come from onshore North America. 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 2007, EnCana purchased approximately 38.9 million shares under the program for a total cost of approximately $2.0 billion.

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

EnCana is organized 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 Corporation's upstream U.S. assets including its key U.S. resource plays
- Integrated Oil Division (formerly known as Integrated Oilsands Division), which includes all of the assets within the integrated oil business (which includes EnCana's interests in Foster Creek, Christina Lake and the U.S. refinery assets) in addition to the Corporation's other bitumen interests and the natural gas assets on the Cold Lake Air Weapons Range
- Offshore & International Division, which includes the Corporation's assets in Atlantic Canada, Brazil, the Middle East and Europe
- 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 2007, for financial reporting purposes, EnCana has defined its operations into the following segments: (i) Canada, United States and Other; (ii) Integrated Oil; (iii) Market Optimization; and (iv) Corporate. All divisions are reported under Canada, United States and Other with the exception of a portion of the Integrated Oil Division and the Midstream & Marketing Division. For financial reporting purposes the integrated oil business with ConocoPhillips is reported under the Integrated Oil segment. The Integrated Oil Division's remaining assets, including the Corporation's other bitumen interests and the natural gas assets on the Cold Lake Air Weapons Range, are reported under Canada, United States and Other. The Midstream & Marketing Division is reported under Market Optimization.

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.

2007 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 bitumen assets. In October 2006, EnCana announced it had entered into an agreement with ConocoPhillips to create an integrated oil business consisting of upstream and downstream assets.

The creation of this business was completed on January 3, 2007. It 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.

- In October 2007, EnCana's Board of Directors authorized funding for the development of the Deep Panuke natural gas project. The Deep Panuke natural gas project involves the installation of the facilities required to produce natural gas from the Deep Panuke field, located approximately 175 kilometres offshore Nova Scotia. Produced gas is expected to be transported by subsea pipeline via the Maritimes & Northeast Pipeline to markets in eastern Canada and the northeastern U.S. Production is expected to be onstream in late 2010.

2007 Acquisitions:

- In November 2007, a subsidiary of EnCana acquired all of the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in Texas for approximately $2.55 billion before closing adjustments. EnCana first entered the Deep Bossier play in 2005 by acquiring a 30 percent interest in the Amoruso Field from Leor Energy, and then increased its interest to 50 percent in June 2006. The November 2007 transaction brings EnCana's interest to 100 percent of the Amoruso Field and added additional production of approximately 75 million cubic feet per day of natural gas.

2007 Divestitures:

- In January 2007, a subsidiary of EnCana completed the sale of all of its interests in its Chad exploration assets for approximately $208 million. The Chad assets included a 50 percent working interest in approximately 54 million gross acres in seven sedimentary basins.
- In February 2007, EnCana completed the sale of The Bow office project assets for approximately $57 million. As part of the transaction, EnCana, as tenant, has signed a 25-year tenant lease agreement for 100 percent of the office space.
- In May 2007, EnCana completed the sale of its Mackenzie Delta and Beaufort Sea licenses and discoveries for proceeds of approximately $159 million.

In addition to the transactions completed in 2007, EnCana also announced in September 2007 that it had reached an agreement to sell all of its remaining interests in Brazil for proceeds of approximately $165 million before closing adjustments. EnCana's Brazil interests include ten offshore exploration blocks. The sale is subject to closing conditions and regulatory approvals, which are expected to be completed in the first half of 2008.

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 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.
- In November 2006, a subsidiary of EnCana completed the second phase in the sale of its 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.

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 has the capacity to import up to 25,000 barrels per day of offshore diluent to help transport its growing bitumen 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:

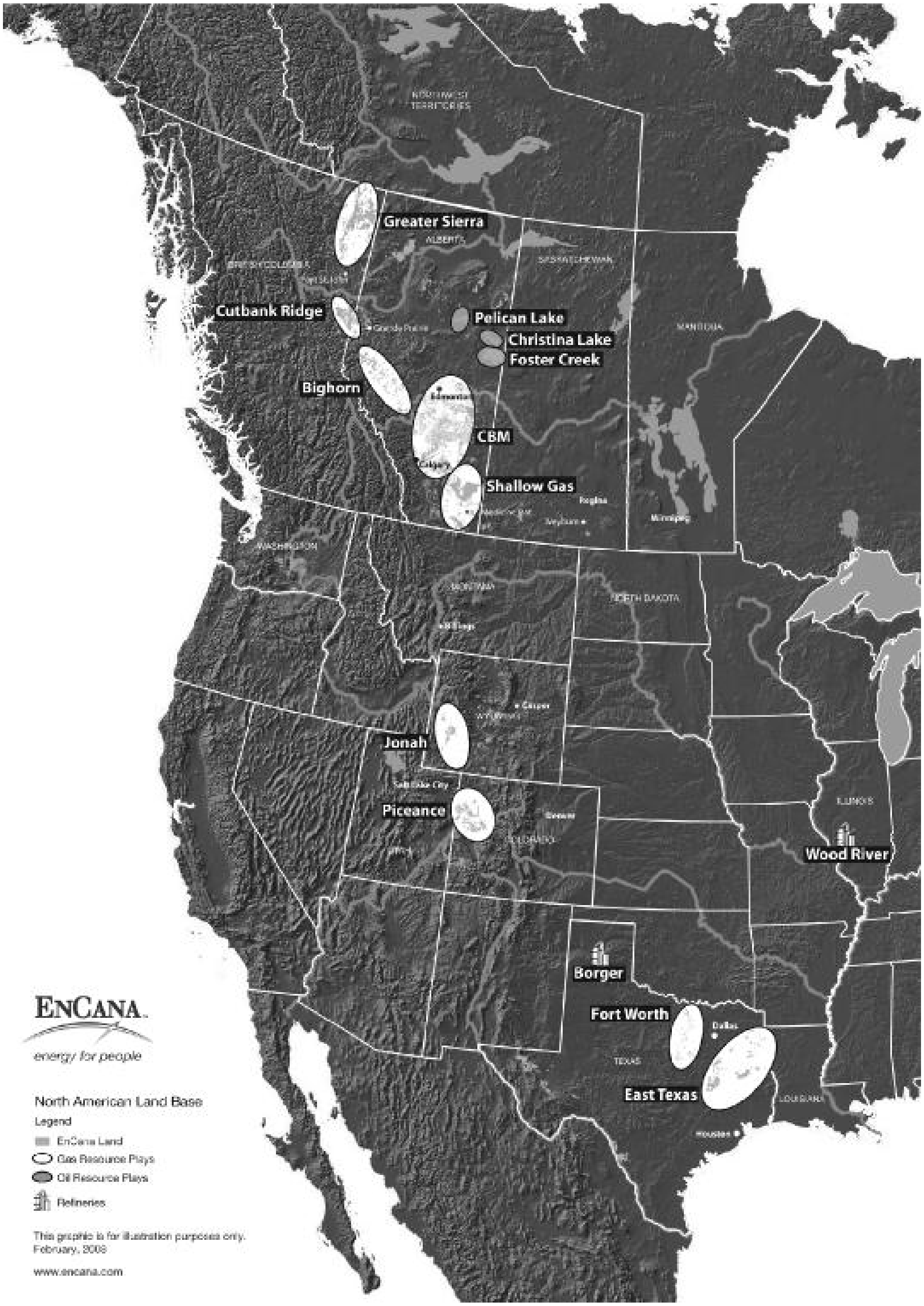
- In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million.
- In December 2005, a subsidiary of EnCana completed the purchase of approximately 24,000 total net acres (2,000 net developed acres) of development land in the Deep Bossier play in East Texas 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. As a result of an expired obligation associated with this divestiture, a gain of $75 million has been recognized in earnings for the year ended December 31, 2007.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2007. The map also identifies the Borger and Wood River refineries.



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 in Atlantic Canada, Brazil, the Middle East and Europe. All of EnCana's proved reserves and production come from onshore North America.

At December 31, 2007, EnCana had net proved reserves of approximately 13.3 trillion cubic feet of natural gas and 0.9 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 77 percent of crude oil and NGLs reserves excluding bitumen and approximately 12 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 23.3 million gross acres (approximately 20.1 million net acres, of which approximately 11.1 million net acres are undeveloped). The mineral rights on approximately 39 percent of the total net acreage are 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 2007, EnCana had total capital investment in western Canada of approximately $3,690 million and drilled approximately 3,837 net wells.

In the U.S., EnCana's landholdings are approximately 6.0 million gross acres (approximately 4.7 million net acres, of which approximately 4.1 million net acres are undeveloped), with the majority in Texas, Colorado, Wyoming and Washington. In 2007, EnCana had total capital investment of approximately $1,919 million and drilled approximately 644 net wells within the U.S.

EnCana's international landholdings are approximately 7.4 million gross acres (approximately 4.2 million net acres), all of which are undeveloped. The majority of the lands are in Atlantic Canada, Brazil, the Middle East and Europe. In 2007, EnCana had total capital investment of approximately $106 million and drilled approximately three net wells internationally.

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 bitumen) 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, Brooks North and Langevin areas.

In 2007, the Canadian Plains Division had total capital investment of approximately $846 million and drilled approximately 2,264 net wells. EnCana's 2008 total capital investment in the Canadian Plains Division is projected to be approximately $820 million, which includes the drilling of approximately 1,360 net wells.

The following table summarizes landholdings for the Canadian Plains Division as at December 31, 2007.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	928	914	65	63	993	977	98%
Brooks North	560	558	9	9	569	567	100%
Langevin	1,250	1,112	1,051	931	2,301	2,043	89%
Drumheller	362	350	17	14	379	364	96%
Pelican Lake	133	133	280	266	413	399	97%
Weyburn	96	84	597	591	693	675	97%
Other	955	890	871	790	1,826	1,680	92%
Canadian Plains Total	4,284	4,041	2,890	2,664	7,174	6,705	93%

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

Production (annual average)	Natural Gas (MMcf/d) 2007	2006	Crude Oil and NGLs (bbls/d) 2007	2006	Total Production (MMcfe/d) 2007	2006
Suffield	245	241	15,563	17,350	338	345
Brooks North	271	272	742	726	275	276
Langevin	219	238	9,542	10,400	277	300
Drumheller	97	104	2,190	2,251	110	118
Pelican Lake	1	2	23,253	23,563	141	143
Weyburn	—	—	14,774	15,136	89	91
Other	42	49	6,136	7,566	78	94
Canadian Plains Total	875	906	72,200	76,992	1,308	1,367

Note:

(1) The Shallow Gas key resource play, contained within the Suffield, Brooks North and Langevin areas, had 2007 average production of approximately 726 million cubic feet per day (739 million cubic feet per day in 2006). Shallow Gas volumes and net wells drilled are reported with commingled volumes from multiple zones within the same geographic area as a result of regulatory approval which was received in late 2006. Figures for 2006 have been restated accordingly.

The following table summarizes EnCana's interests in producing wells as at December 31, 2007. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2007.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	9,512	9,494	719	719	10,231	10,213
Brooks North	6,543	6,438	44	44	6,587	6,482
Langevin	6,613	6,067	225	220	6,838	6,287
Drumheller	1,357	1,305	101	99	1,458	1,404
Pelican Lake	6	6	438	438	444	444
Weyburn	—	—	1,037	478	1,037	478
Other	1,158	1,140	703	661	1,861	1,801
Canadian Plains Total	25,189	24,450	3,267	2,659	28,456	27,109

Note:

(1) At December 31, 2007, the Shallow Gas key resource play had 22,668 gross producing gas wells (21,999 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 2008, as part of its ongoing application to continue shallow gas infill drilling in the National Wildlife Area, EnCana will be participating in an Energy Resources Conservation Board ("ERCB") (as of January 1, 2008, the Alberta Energy & Utilities Board or EUB has been realigned into two separate bodies; the ERCB regulates the oil and gas industry) joint panel hearing as part of the Canadian Environmental Assessment Act. In 2007, EnCana drilled approximately 928 net wells in the Suffield area and production averaged approximately 245 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 North 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 2007, EnCana drilled approximately 602 net wells in the area and production averaged approximately 271 million cubic feet per day of natural gas.

Langevin

The Langevin area produces shallow gas predominantly from the Upper Cretaceous formations in southeast Alberta and southwestern Saskatchewan. Gas production in this area is from a mix of fee title and Crown lands and is included in EnCana's Shallow Gas key resource play. Crude oil production in the area is predominantly from fee title lands located south of Brooks, Alberta. Development of this area focuses on infill drilling and optimization of existing wells. In 2007, EnCana drilled approximately 450 net wells in the area and production averaged approximately 219 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 gas play, and is largely comprised of EnCana fee title lands. In 2007, EnCana drilled approximately 204 net wells in the area and production averaged approximately 97 million cubic feet per day of natural gas.

Pelican Lake

Pelican Lake is one of EnCana's key resource plays producing heavy crude oil in northeast Alberta. In 2007, EnCana continued its expansion of its facility infrastructure to accommodate higher total fluid production volumes associated with its waterflood and polymer projects. EnCana also expanded its polymer program from 37 injection wells at the end of 2006 to 60 wells at the end of 2007.

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.

The Pelican Lake project reached royalty payout in 2006, changing the royalty from one percent of gross revenues to 25 percent of net revenues.

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 2007, EnCana continued its infill drilling program with 59 new wells in the unit. As of December 31, 2007, there were 45 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 ("CBM"). The CBM key resource play (Horseshoe Canyon coalbed methane and commingled shallow gas) is located within the Clearwater business unit.

In 2007, the Canadian Foothills Division had total capital investment of approximately $2,392 million and drilled approximately 1,539 net wells. EnCana's 2008 total capital investment in the Canadian Foothills Division is projected to be approximately $2,094 million, which includes the drilling of approximately 775 net wells.

The following table summarizes landholdings for the Canadian Foothills Division as at December 31, 2007.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	687	611	2,053	1,814	2,740	2,425	89%
Cutbank Ridge	245	210	839	752	1,084	962	89%
Bighorn	316	174	754	456	1,070	630	59%
Clearwater	3,561	3,159	3,350	3,140	6,911	6,299	91%
Sexsmith/Hythe/Saddle Hills	354	218	214	166	568	384	68%
Other	248	172	1,300	839	1,548	1,011	65%
Canadian Foothills Total	5,411	4,544	8,510	7,167	13,921	11,711	84%

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

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2007	2006	2007	2006	2007	2006
Greater Sierra	211	213	852	837	216	218
Cutbank Ridge	234	170	98	82	235	170
Bighorn	119	91	1,803	1,480	130	100
Clearwater(1)	497	483	10,595	11,555	561	552
Sexsmith/Hythe/Saddle Hills	82	93	2,015	2,046	94	105
Other	112	116	2,909	3,370	129	136
Canadian Foothills Total	1,255	1,166	18,272	19,370	1,365	1,281

Note:

(1) The CBM key resource play, located within the Clearwater business unit, had 2007 average production of approximately 259 million cubic feet per day (194 million cubic feet per day in 2006).

The following table summarizes EnCana's interests in producing wells as at December 31, 2007. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2007.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	960	896	3	3	963	899
Cutbank Ridge	470	417	—	—	470	417
Bighorn	295	193	1	—	296	193
Clearwater(1)	8,281	7,566	180	112	8,461	7,678
Sexsmith/Hythe/Saddle Hills	292	246	72	54	364	300
Other	613	456	175	96	788	552
Canadian Foothills Total	10,911	9,774	431	265	11,342	10,039

Note:

(1) At December 31, 2007, the CBM key resource play had 4,926 gross producing gas wells (4,627 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. Primary focus is on the continued development of the Devonian Jean Marie formation and the pilot development of the Devonian Shale formation.

In 2007, EnCana drilled approximately 109 net natural gas wells in the area and production averaged approximately 211 million cubic feet per day of natural gas. Production has remained relatively constant over the past two years as EnCana has reduced capital expenditures, and is currently targeting a load leveled drilling program that is expected to continue to maintain current production levels.

EnCana controls approximately 346,000 undeveloped gross acres (205,000 net acres) in the emerging Devonian Shale formation of the Horn River Basin in northeast British Columbia. The Horn River Formation shales (Muskwa, Otter Park and Evie) in EnCana's focus area are upwards of 360 feet thick and to date have been evaluated with six wells (five vertical and one horizontal), two of which have been placed on long-term production. In 2008, EnCana plans to drill, complete and tie-in four horizontal wells and participate in three others.

As at December 31, 2007, 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. The Cadomin and Montney formations are almost exclusively being developed with horizontal well technology. In 2007, significant improvements were achieved with respect to horizontal well completions with the application of multi-stage hydraulic fracturing. In 2007, EnCana drilled approximately 81 net natural gas wells in the area and production averaged approximately 234 million cubic feet per day of natural gas.

EnCana's Steeprock plant has a capacity of approximately 70 million cubic feet per day and is currently under expansion to process an anticipated total of 140 million cubic feet per day.

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. The primary producing properties in Bighorn are Wild River, Resthaven, Kakwa, Berland and Aurora. In 2007, EnCana drilled approximately 58 net wells in the area and production averaged approximately 119 million cubic feet per day of sweet natural gas.

In 2007, new technology and regulatory approval permitting the reporting of production of commingled volumes from multiple zones allowed for significant advancements in well cost and cycle times. Pad drilling and simultaneous operations commenced in most of the areas. Well costs were reduced by approximately 25 percent and cycle times decreased by approximately 49 percent.

EnCana has a working interest in a number of natural gas plants within Bighorn. The Resthaven plant, in which EnCana has a 65 percent working interest, has a capacity of approximately 100 million cubic feet per day. The Kakwa gas plant has a capacity of approximately 30 million cubic feet per day. EnCana owns 50 percent of this plant and has firm processing capacity for the remaining 50 percent. The Wild River plant, in which EnCana holds a 70 percent working interest, has a capacity of approximately 30 million cubic feet per day and the Berland River plant, in which EnCana holds a 24 percent working interest, has a capacity of approximately 40 million cubic feet per day. In June 2007, a 20 million cubic feet per day compressor station was commissioned at Aurora along with a 27 kilometre pipeline to move the first gas volumes from this emerging property.

Clearwater

The Clearwater business unit extends from the U.S. border to just north of Edmonton. The primary focus of Clearwater is the CBM key natural gas resource play; however, Clearwater is also responsible for 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 2007, EnCana drilled approximately 1,079 net CBM wells and production averaged approximately 259 million cubic feet per day of natural gas from the CBM key 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 operates and has a 62 percent interest in the 210 million cubic feet per day Sexsmith sour natural gas and liquids processing plant. EnCana also operates and owns 100 percent of 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. In addition, EnCana owns and operates a 275-kilometre natural gas gathering system in the area. The production in this area has steadily declined over the last several years and it is no longer a primary area of focus.

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 and Fort Worth basins in Texas. The USA Division also has landholdings in the Columbia River Basin in Washington State and the Maverick Basin in Texas. 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 2007, the USA Division had total capital investment of approximately $1,919 million and drilled approximately 644 net wells. EnCana's 2008 total capital investment in the USA Division is projected to be approximately $2,510 million, which includes the drilling of approximately 650 net wells.

The following table summarizes landholdings for the USA Division as at December 31, 2007.

Landholdings (thousands of acres)	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working Interest**
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Jonah	12	10	146	134	158	144	91%
Piceance	252	240	708	659	960	899	94%
East Texas	102	65	294	245	396	310	78%
Fort Worth	56	53	121	90	177	143	81%
Maverick Basin	17	15	345	220	362	235	65%
Columbia River Basin	—	—	878	397	878	397	45%
Other	278	186	2,777	2,375	3,055	2,561	84%
USA Total	717	569	5,269	4,120	5,986	4,689	78%

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)	
	2007	2006	2007	2006	2007	2006
Jonah	557	464	5,345	4,257	589	489
Piceance	348	326	2,755	2,416	364	341
East Texas	143	99	207	277	145	100
Fort Worth	124	101	497	607	127	105
Other	173	192	5,376	5,401	205	225
USA Total	1,345	1,182	14,180	12,958	1,430	1,260

The following table summarizes EnCana's interests in producing wells as at December 31, 2007. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2007.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Jonah	823	732	—	—	823	732
Piceance	2,614	2,306	—	—	2,614	2,306
East Texas	727	438	—	—	727	438
Fort Worth	711	616	—	—	711	616
Other	2,352	1,553	8	4	2,360	1,557
USA Total	7,227	5,645	8	4	7,235	5,649

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 13,000 feet. The wells are stimulated with multi-stage advanced hydraulic fracturing techniques.

EnCana currently plans to drill the field to ten acre spacing and has approximately 430 net remaining ten acre locations left to drill. Additional locations at tighter spacing are available if required to achieve optimal recovery. In 2007, EnCana drilled approximately 135 net wells in the Jonah area and production of natural gas averaged approximately 557 million cubic feet per day.

Piceance

The Piceance Basin in northwest Colorado is one of EnCana's key natural gas resource plays. The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. EnCana's May 2004 acquisition of Tom Brown, Inc. included properties and natural gas production in the basin. In 2007, EnCana drilled approximately 286 net wells in the basin and production of natural gas averaged approximately 348 million cubic feet per day.

In 2006, EnCana finalized four agreements to jointly develop portions of the Piceance Basin. For the period 2007 to 2009, it is expected that EnCana will drill approximately 267 wells with third party funds and EnCana's partners will fund the drilling of approximately 182 more wells, allowing the third parties to earn approximately 20,000 net acres. During 2007, EnCana drilled approximately 131 net wells with third party funds and our partners drilled approximately 30 more wells.

In 2007, EnCana executed another development agreement with a third party, encompassing approximately 13,000 acres. EnCana's partner is expected to drill 64 wells by June 1, 2009, of which approximately 20 wells were drilled in 2007.

East Texas

EnCana produces natural gas and associated NGLs in the East Texas Basin, one of EnCana's key resource plays. EnCana first entered East Texas with the acquisition of Tom Brown, Inc. in 2004. In 2005, EnCana entered the Deep Bossier play through an acquisition of a 30 percent interest in the Leor Energy group's Deep Bossier assets. Subsequently, in 2006, EnCana increased this interest to 50 percent. In November 2007, EnCana acquired the Leor Energy group's remaining interests in the Deep Bossier play as well as additional East Texas acreage. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2007, EnCana drilled approximately 35 net wells in the basin and production averaged approximately 143 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. EnCana drilled approximately 75 net wells in the basin in 2007 and production averaged approximately 124 million cubic feet per day of natural gas.

Maverick Basin

EnCana controls approximately 345,000 undeveloped gross acres (220,000 net acres) in the Maverick Basin of southwest Texas. This acreage, acquired in September 2005, contains significant exploratory potential in the Pearsall Shale, plus multi-zone potential in the uphole section. In 2007, EnCana entered into a joint venture agreement to drill between three and seven wells, with an option to drill more. The first of these wells is expected to be drilled and tested in the first quarter of 2008.

Columbia River Basin

EnCana currently holds approximately 400,000 net acres in the Columbia River Basin. In 2007, EnCana concluded a three well exploration program in the basin that was funded by third party capital. The exploration wells did not flow commercial quantities of gas. EnCana has no immediate plans for further drilling in the basin.

Gathering & Processing Facilities

EnCana owns and operates various gas gathering and processing facilities within the USA Division. The Corporation's gathering, compression and processing facilities in the Piceance Basin include over 2,500 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 715 kilometres of pipeline. 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 Oil Division

The Integrated Oil Division includes all of the assets within the integrated oil business with ConocoPhillips described below, as well as the Corporation's other bitumen interests and the natural gas assets located on the Cold Lake Air Weapons Range. The Division has assets in both Canada and the U.S. and contains two key crude oil resource plays: (i) Foster Creek; and (ii) Christina Lake. As at December 31, 2007, the Corporation held bitumen rights of approximately 953,000 gross acres (656,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 629,000 net acres on behalf of itself and/or its assignees on the Cold Lake Air Weapons Range.

In 2007, the Integrated Oil Division had total capital investment of approximately $671 million and drilled approximately 35 net wells. EnCana's 2008 total capital investment in the Integrated Oil Division is projected to be approximately $1,287 million which includes the drilling of approximately 42 net wells. Approximately $1,165 million of the total capital investment is related to the Foster Creek and Christina Lake oil projects and refinery expansion projects associated with the integrated oil business.

The following table summarizes landholdings for the Integrated Oil Division as at December 31, 2007.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Cold Lake Air Weapons Range	415	392	405	375	820	767	94%
Foster Creek[(1)]	24	12	48	31	72	43	60%
Christina Lake	1	—	27	14	28	14	50%
Borealis	—	—	37	37	37	37	100%
Other	173	103	1,090	767	1,263	870	69%
Integrated Oil Total	613	507	1,607	1,224	2,220	1,731	78%

Note:

(1) As of December 31, 2007, ConocoPhillips had not made an election to acquire an undivided 50 percent working interest share of a recent lease acquisition under an area of mutual interest arrangement with EnCana.

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)	
	2007	2006	2007	2006	2007	2006
Cold Lake Air Weapons Range	86	106	—	—	86	106
Foster Creek	—	—	24,262	36,910	146	221
Christina Lake	—	—	2,552	5,858	15	35
Other	5	7	2,688	5,185	21	38
Integrated Oil Total	91	113	29,502	47,953	268	400

Note:

(1) 2007 production shown reflects the contribution of Foster Creek and Christina Lake into the integrated oil business with ConocoPhillips. 2006 production is shown prior to the contribution of Foster Creek and Christina Lake into the integrated oil business with ConocoPhillips.

The following table summarizes EnCana's interests in producing wells as at December 31, 2007. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2007.

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	707	664	—	—	707	664
Foster Creek	—	—	84	42	84	42
Christina Lake	6	3	9	5	15	8
Other	—	—	26	23	26	23
Integrated Oil Total	713	667	119	70	832	737

The following describes EnCana's major producing areas or activities in the Integrated Oil 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 2007, natural gas production was impacted by the September 2003, July 2004, September 2004 and July 2007 ERCB decisions to shut-in McMurray, Wabiska and Clearwater natural gas production that may put at risk the recovery of bitumen resources in the area. The decisions resulted in a decrease in annualized natural gas production of approximately 20 million cubic feet per day in 2007 (18 million cubic feet per day in 2006). On September 1, 2007, approximately 29 additional wells were shut-in in accordance with the July 2007 ERCB decision. There were no additional wells shut-in in 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.

Foster Creek

At December 31, 2007, EnCana had a 50 percent working interest in Foster Creek, one of EnCana's key crude oil resource plays. EnCana holds surface access rights from the Governments of Canada and Alberta and bitumen 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 bitumen rights in other areas on the Cold Lake Air Weapons Range on behalf of itself and/or its assignees. EnCana is currently operating an in-situ 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 of bitumen per day of capacity, increasing production capacity at Foster Creek to approximately 60,000 barrels per day. Current expansions are already underway and are expected to increase production capacity to approximately 120,000 barrels of bitumen 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. 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, 2007, EnCana had 68 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 natural gas for the production of 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.

EnCana continues to operate its 80 megawatt natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. The steam and power 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

At December 31, 2007, EnCana had a 50 percent working interest in a SAGD oil recovery project at Christina Lake, one of EnCana's key crude oil resource plays. Current expansions already underway are expected to increase production capacity to approximately 18,000 barrels per day by the second half of 2008. In 2007, EnCana continued to utilize the remote water disposal system to successfully manage bottom water pressures and improve the steam-oil ratio.

The next phase of expansion at Christina Lake which is expected to increase production capacity by approximately 40,000 barrels of bitumen per day has been approved by the FCCL Oil Sands Partnership ("FCCL"). Regulatory approval had previously been received for development at Christina Lake for up to 70,000 barrels of bitumen per day. In July 2007, EnCana filed an amended application with the ERCB to expand the Christina Lake development plan to 100,000 barrels of bitumen per day. Approval of the amended plan is expected by mid-year 2008, with construction expected to take approximately two years to complete. This next phase of expansion is expected to increase production capacity to approximately 58,000 barrels of bitumen per day.

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. This second SAP test well is scheduled to start steaming in 2008 and is expected to provide information on optimal well spacing. Business cases are being evaluated for the potential use of this technology in the Christina Lake development plan.

Borealis

EnCana has a 100 percent working interest in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. Borealis is not included in the venture with ConocoPhillips. As of December 31, 2007, EnCana has drilled approximately 191 delineation wells in the Greater Borealis area since 2000. A joint application for development has been submitted to the ERCB and Alberta Environment that would allow for the construction of a SAGD facility with production capacity of approximately 35,000 barrels of bitumen per day. Production from this facility is expected to commence in 2015. In 2008, EnCana plans to continue its evaluation of the Greater Borealis area by drilling nine more wells to test specific reservoir properties of the McMurray Formation and to test for potential water disposal zones.

Integrated Oil Business

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

The upstream portion of the integrated oil business is conducted through FCCL which owns the Foster Creek and Christina Lake in-situ oil recovery projects contributed by EnCana. EnCana and ConocoPhillips each own 50 percent of FCCL. EnCana is the operating and managing partner of FCCL. The downstream portion of the integrated 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 held a disproportionate economic interest in the Borger refinery of 85 percent in 2007 and will have a 65 percent interest in 2008 before reverting to 50 percent in 2009. ConocoPhillips is the operator and manager of WRB. FCCL 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 FCCL is to increase production 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 following table summarizes the combined refineries' key operational results for 2007.

Refinery Operations[(1)]	**2007**
Crude Oil Capacity (Mbbls/d)	452
Crude Oil Runs (Mbbls/d)	432
Crude Utilization (%)	96%
Refined Products (Mbbls/d)	
Gasoline	246
Distillates	128
Other	83
Total	457

Note:

(1) Represents 100 percent of the Wood River and Borger refinery operations.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 barrels per day of crude oil and approximately 45,000 barrels per day of NGLs. It processes mainly medium, high-sulphur and heavy, high-sulphur crude oil and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the mid-continent. In July 2007, a new coker with a capacity of approximately 25,000 barrels per day was brought into service along with a new vacuum unit and revamped gas oil and distillate hydrotreaters. This project has enabled the refinery to process heavy oil blends, particularly Canadian bitumen, and comply with clean fuel regulations for ultra-low sulphur diesel and low-sulphur gasoline. The project has also enabled compliance with required reductions of sulphur dioxide emissions.

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 barrels per day of crude oil. It processes mainly light, low-sulphur and heavy, high-sulphur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstocks and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the midwest. In early 2007, the refinery completed the construction of a facility utilizing proprietary sulphur removal technology for the production of low-sulphur gasoline.

The goal of WRB is to refine approximately 275,000 barrels per day of bitumen to primarily motor fuels by 2015. Currently, WRB has processing capability to refine up to approximately 70,000 barrels per day of bitumen.

Offshore & International Division

The Offshore & International Division invests a small portion of EnCana's capital in exploration opportunities, primarily in Atlantic Canada, Brazil, the Middle East and Europe. In 2007, EnCana's Offshore & International Division had total capital investment of approximately $106 million and drilled approximately three net wells. EnCana's 2008 total capital investment in the Offshore & International Division is projected to be approximately $56 million, which includes the drilling of approximately one net well and the commencement of the major contracting activities related to the development of the Deep Panuke natural gas project.

Atlantic Canada

At December 31, 2007, EnCana held an interest in approximately 533,000 gross acres (177,000 net acres) in Atlantic Canada, which includes Nova Scotia and Newfoundland and Labrador. EnCana operates five of its ten licenses in these areas and has an average working interest of approximately 33 percent.

EnCana is the operator of the Deep Panuke gas field, located offshore Nova Scotia, and has an approximate 78 percent interest at December 31, 2007, based upon proposed unitization. EnCana is currently moving forward with the development of the Deep Panuke natural gas 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 the Deep Panuke natural gas project. Subsequently, in November 2006, EnCana filed the

Development Plan Application ("DPA") 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. Regulatory approval of the DPA was received from the Governments of Nova Scotia and Canada on October 2, 2007. EnCana's Board of Directors authorized funding for the development of the Deep Panuke natural gas project on October 23, 2007. In November 2007, EnCana announced it had entered into an agreement with Single Buoy Moorings Inc. for the provision and operation of the Deep Panuke production field centre. The Deep Panuke natural gas project is expected to start production in late 2010.

Brazil

EnCana has non-operated interests in ten 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 (522,000 net acres) with an average working interest of approximately 31 percent.

In September 2007, EnCana reached an agreement to sell all of its remaining interests in Brazil. The sale is subject to closing conditions and regulatory approvals, which are expected to be completed in the first half of 2008.

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). One well commenced drilling in the third quarter of 2007 and completed drilling in January 2008. The results are currently being evaluated. A second well is scheduled for the first quarter of 2008.

Greenland

At December 31, 2007, EnCana had an approximate 87 percent working interest in two exploration blocks offshore Greenland, comprising approximately 1.7 million gross acres (1.5 million net acres). In late 2007, EnCana received regulatory approval for the farmout of 40 percent of its interest in both blocks effective January 1, 2008. EnCana plans to conduct a seabed logging program in 2008 as part of its current work commitment.

France

EnCana has 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 drilled two exploration wells in 2007. Both wells have been abandoned. EnCana continues to evaluate plans for 2008.

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 2007, approximately 92 percent of EnCana's sales of produced natural gas were directly marketed by EnCana to local distribution companies, industrials, other producers and energy marketing companies. The remaining eight percent of sales of produced natural gas 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 2008, after taking into account its risk management contracts, EnCana's gas sales price portfolio exposure consists of approximately 1.6 billion cubic feet per day for 2008 at an average fixed NYMEX price of approximately $8.21 per million cubic feet with the remainder unhedged. Details of these transactions are found in Note 18 to EnCana's audited consolidated financial statements for the year ended December 31, 2007.

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. (95,082 barrels per day in 2007 and 132,760 barrels per day in 2006). Crude oil sales are normally executed under spot, term 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 2007, EnCana provided marketing services to the ADOE (17,314 barrels per day in 2007 and 45,542 barrels per day in 2006). This agency agreement ended in May of 2007. Additionally, in 2007, EnCana marketed 71,415 barrels per day of blend oil on behalf of FCCL. This agency agreement became effective on January 2, 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 18 to EnCana's audited consolidated financial statements for the year ended December 31, 2007.

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 Oil 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 2007, 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 by approximately seven percent in 2007 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,776 billion cubic feet. Changes in the revisions and improved recovery category for natural gas reserves were positive at 165 billion cubic feet, or approximately one percent of proved natural gas reserves at the beginning of 2007. Reserve additions from revisions and improved recovery and extensions and discoveries were generally equally distributed between Canada and the U.S. Approximately 12 percent of natural gas additions in 2007 were due to acquisitions, with approximately 75 percent of these additions attributable to the Leor Energy group acquisition.

In 2006 and 2005, natural gas reserves increased primarily from development and exploration drilling.

EnCana's crude oil and NGLs reserves were down approximately eighteen percent at year end 2007 in comparison to year end 2006 as a consequence of the contribution of the Corporation's interests in Foster Creek and Christina Lake into the integrated oil business effective January 2, 2007. Subsequent to this transaction, EnCana's crude oil and NGLs reserves increased approximately 26 percent over the balance of the year, mainly due to additions at Foster Creek and Christina Lake.

In 2006, significant increases in proved reserves primarily at Foster Creek and Christina Lake 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.

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 2007 prices were as follows: crude oil (WTI) $95.95/bbl, (Edmonton Light) C$93.39/bbl, increases of 58 percent and 38 percent from year end 2006, respectively; Foster Creek field price C$49.60/bbl, an increase of 41 percent from year end 2006; natural gas (Henry Hub) $6.80/MMbtu, an increase of 20 percent from year end 2006; and natural gas (AECO) C$6.63/MMbtu, an increase of 9 percent from year end 2006.

Each year, EnCana reviews the methodologies employed to arrive at year end prices to ensure that they are determined in a manner which is most consistent with SEC standards. At year end 2007, this review has resulted in EnCana changing its methodology with respect to bitumen price determination, placing greater emphasis on spot prices for the Western Canadian Select marker.

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	Total	Canada	United States	Ecuador	Total
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(3)	—	—	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(4)	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(5)	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(5)	54.0	—	1,133.4
2007							
Beginning of year	7,028	5,390	12,418	1,079.4	54.0	—	1,133.4
FCCL Partnership contribution	—	—	—	(398.0)(5)	—	—	(398.0)
Effective Jan 2, 2007	7,028	5,390	12,418	681.4	54.0	—	735.4
Revisions and improved recovery	87	78	165	75.5	3.6	—	79.1
Extensions and discoveries	949	827	1,776	155.8	5.9	—	161.7
Purchase of reserves in place	63	211	274	0.2	—	—	0.2
Sale of reserves in place	(24)	(7)	(31)	(0.2)	—	—	(0.2)
Production	(811)	(491)	(1,302)	(43.8)	(5.2)	—	(49.0)
End of year	7,292	6,008	13,300	868.9	58.3	—	927.2
Developed	4,868	3,368	8,236	289.5	37.0	—	326.5
Undeveloped	2,424	2,640	5,064	579.4	21.3	—	600.7
Total	7,292	6,008	13,300	868.9	58.3	—	927.2

Notes:

(1) Definitions:

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

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

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

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

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

(3) 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.

(4) The Corporation divested its Ecuadorian operations in 2006.

(5) 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 FCCL 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.

(6) In October, 2007, the Government of Alberta announced proposed changes to its provincial royalty regime effective January 1, 2009. In accordance with U.S. disclosure requirements, the reserves estimates at December 31, 2007 have been prepared using royalty regimes then in effect.

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		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
	($ millions)					
Future cash inflows	95,778	72,262	71,786	38,398	27,165	40,504
Less future:						
Production costs	25,089	20,471	16,765	5,869	4,123	3,262
Development costs	10,171	9,355	6,164	6,943	4,715	4,174
Asset retirement obligation payments	3,320	2,397	2,269	532	396	264
Income taxes	12,871	8,816	13,170	7,375	5,349	11,041
Future net cash flows	44,327	31,223	33,418	17,679	12,582	21,763
Less 10% annual discount for estimated timing of cash flows	21,663	14,627	13,281	8,196	6,128	10,291
Discounted future net cash flows	22,664	16,596	20,137	9,483	6,454	11,472

	Ecuador			Total		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
	($ millions)					
Future cash inflows	—	—	5,350	134,176	99,427	117,640
Less future:						
Production costs	—	—	2,093	30,958	24,594	22,120
Development costs	—	—	429	17,114	14,070	10,767
Asset retirement obligation payments	—	—	24	3,852	2,793	2,557
Income taxes	—	—	662	20,246	14,165	24,873
Future net cash flows	—	—	2,142	62,006	43,805	57,323
Less 10% annual discount for estimated timing of cash flows	—	—	574	29,859	20,755	24,146
Discounted future net cash flows	—	—	1,568	32,147	23,050	33,177

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

	Canada			United States		
	2007	2006	2005	2007	2006	2005
	($ millions)					
Balance, beginning of year	16,596	20,137	12,178	6,454	11,472	7,488
Changes resulting from:						
Sales of oil and gas produced during the period	(6,055)	(5,970)	(5,720)	(3,281)	(2,373)	(2,436)
Discoveries and extensions, net of related costs	3,796	2,584	4,278	1,591	877	3,582
Purchases of proved reserves in place	129	—	26	372	69	237
Sales of proved reserves in place	(2,933)	(19)	(279)	(15)	(85)	(486)
Net change in prices and production costs	11,077	(5,797)	11,624	4,818	(7,636)	4,716
Revisions to quantity estimates	823	155	1,071	830	265	(700)
Accretion of discount	2,087	2,809	1,629	924	1,714	1,103
Previously estimated development costs incurred net of change in future development costs	(667)	(805)	(888)	(907)	(350)	162
Other	(82)	(174)	63	(113)	(381)	(64)
Net change in income taxes	(2,107)	3,676	(3,845)	(1,190)	2,882	(2,130)
Balance, end of year	22,664	16,596	20,137	9,483	6,454	11,472

	Ecuador			Total		
	2007	2006	2005	2007	2006	2005
	($ millions)					
Balance, beginning of year	—	1,568	1,202	23,050	33,177	20,868
Changes resulting from:						
Sales of oil and gas produced during the period	—	(142)	(604)	(9,336)	(8,485)	(8,760)
Discoveries and extensions, net of related costs	—	—	159	5,387	3,461	8,019
Purchases of proved reserves in place	—	—	—	501	69	263
Sales of proved reserves in place	—	(1,359)	—	(2,948)	(1,463)	(765)
Net change in prices and production costs	—	—	967	15,895	(13,433)	17,307
Revisions to quantity estimates	—	—	88	1,653	420	459
Accretion of discount	—	—	147	3,011	4,523	2,879
Previously estimated development costs incurred net of change in future development costs	—	(46)	(148)	(1,574)	(1,201)	(874)
Other	—	—	8	(195)	(555)	7
Net change in income taxes	—	(21)	(251)	(3,297)	6,537	(6,226)
Balance, end of year	—	—	1,568	32,147	23,050	33,177

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador[1]		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	7,362	7,190	6,701	4,065	3,096	3,052	—	190	873
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,307	1,220	981	784	723	616	—	48	269
Depreciation, depletion and amortization	2,298	2,146	1,961	1,181	869	712	—	84	234
Operating income (loss)	3,757	3,824	3,759	2,100	1,504	1,724	—	58	370
Income taxes	1,114	1,235	1,274	809	556	638	—	21	134
Results of operations	2,643	2,589	2,485	1,291	948	1,086	—	37	236

	Other			Total		
	2007	2006	2005	2007	2006	2005
	($ millions)					
Oil and gas revenues, net of royalties, transportation and selling costs	(1)	2	—	11,426	10,478	10,626
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	18	11	6	2,109	2,002	1,872
Depreciation, depletion and amortization	69	10	8	3,548	3,109	2,915
Operating income (loss)	(88)	(19)	(14)	5,769	5,367	5,839
Income taxes	—	—	—	1,923	1,812	2,046
Results of operations	(88)	(19)	(14)	3,846	3,555	3,793

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		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
	($ millions)								
Proved oil and gas properties	36,874	31,546	27,074	13,738	9,796	7,753	—	—	1,926
Unproved oil and gas properties	1,380	1,700	1,998	1,852	1,221	870	—	—	18
Total capital cost	38,254	33,246	29,072	15,590	11,017	8,623	—	—	1,944
Accumulated DD&A	19,286	14,261	12,131	3,783	2,595	1,750	—	—	778
Net capitalized costs	18,968	18,985	16,941	11,807	8,422	6,873	—	—	1,166

	Other			Total		
	2007	2006	2005	2007	2006	2005
	($ millions)					
Proved oil and gas properties	—	—	—	50,612	41,342	36,753
Unproved oil and gas properties	297	361	470	3,529	3,282	3,356
Total capital cost	297	361	470	54,141	44,624	40,109
Accumulated DD&A	160	98	222	23,229	16,954	14,881
Net capitalized costs	137	263	248	30,912	27,670	25,228

Costs Incurred

	Canada			United States			Ecuador		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
				($ millions)					
Acquisitions									
— Unproved	28	—	—	1,048	278	271	—	—	—
— Proved	61	47	30	1,565	6	141	—	—	—
Total acquisitions	89	47	30	2,613	284	412	—	—	—
Exploration costs	427	403	817	48	236	264	—	1	15
Development costs	3,309	3,611	3,333	1,871	1,826	1,724	—	46	164
Total costs incurred	3,825	4,061	4,180	4,532	2,346	2,400	—	47	179

	Other			Total		
	2007	2006	2005	2007	2006	2005
			($ millions)			
Acquisitions						
— Unproved	—	—	—	1,076	278	271
— Proved	—	—	—	1,626	53	171
Total acquisitions	—	—	—	2,702	331	442
Exploration costs	60	75	70	535	715	1,166
Development costs	—	—	—	5,180	5,483	5,221
Total costs incurred	60	75	70	8,417	6,529	6,829

Production Volumes and Per-Unit Results

Production Volumes

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

	Production Volumes — 2007				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada	2,221	2,258	2,243	2,203	2,178
United States	1,345	1,464	1,387	1,303	1,222
Total Produced Gas	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	40,690	40,462	40,345	40,025	41,946
Heavy Oil — Foster Creek/Christina Lake	26,814	27,190	28,740	27,994	23,269
Heavy Oil — Other	41,472	41,621	40,882	40,897	42,500
Natural Gas Liquids(1)					
Canada	11,316	12,388	11,141	11,017	10,700
United States	13,862	14,476	15,275	13,483	12,175
Total Oil and Natural Gas Liquids	134,154	136,137	136,383	133,416	130,590
Total Continuing Operations ***(MMcfe/d)***	4,371	4,539	4,448	4,306	4,184

Note:

(1) Natural gas liquids include condensate volumes.

	Production Volumes — 2006				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada	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	44,440	41,972	46,454	43,672	45,680
Heavy Oil — Foster Creek/Christina Lake	42,768	46,678	43,073	39,215	42,050
Heavy Oil — Other	45,858	41,913	43,287	44,572	53,822
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	157,273	154,669	156,721	151,859	165,973
Total Continuing Operations ***(MMcfe/d)***	4,311	4,334	4,299	4,272	4,339
Discontinued Operations:					
Ecuador *(bbls/d)*	11,996	—	—	—	48,650
Total Discontinued Operations ***(MMcfe/d)***	72	—	—	—	292
Total ***(MMcfe/d)***	4,383	4,334	4,299	4,272	4,631

Note:

(1) Natural gas liquids include condensate volumes.

	Production Volumes — 2005				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada	2,125	2,172	2,123	2,151	2,052
United States	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	3,220	3,326	3,222	3,212	3,119
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	47,032	45,777	42,989	48,381	51,084
Heavy Oil — Foster Creek/Christina Lake	34,379	39,839	32,580	31,025	34,027
Heavy Oil — Other	49,814	52,625	50,856	49,421	46,273
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	156,807	163,352	152,480	153,641	157,742
Total Continuing Operations ***(MMcfe/d)***	4,161	4,306	4,137	4,134	4,065
Discontinued Operations:					
Ecuador *(bbls/d)*	72,916	70,480	71,896	73,662	75,695
Total Discontinued Operations ***(MMcfe/d)***	437	423	431	442	454
Total ***(MMcfe/d)***	4,598	4,729	4,568	4,576	4,519

Note:

(1) Natural gas liquids include condensate volumes.

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 — 2007				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price	6.20	6.35	5.36	6.76	6.36
Production and mineral taxes	0.09	0.03	0.10	0.11	0.10
Transportation and selling	0.35	0.35	0.34	0.36	0.36
Operating	0.92	1.03	0.83	0.90	0.91
Netback	4.84	4.94	4.09	5.39	4.99
Produced Gas — United States ($/Mcf)					
Price	5.38	5.03	4.68	5.73	6.24
Production and mineral taxes	0.34	0.29	0.38	0.17	0.53
Transportation and selling	0.62	0.64	0.60	0.65	0.61
Operating	0.65	0.70	0.52	0.71	0.67
Netback	3.77	3.40	3.18	4.20	4.43
Produced Gas — Total ($/Mcf)					
Price	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	0.18	0.14	0.21	0.14	0.26
Transportation and selling	0.45	0.46	0.44	0.47	0.45
Operating	0.82	0.90	0.72	0.83	0.82
Netback	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids — Canada ($/bbl)					
Price	59.34	73.39	62.87	55.21	43.26
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.01	0.96	1.80	0.74	0.54
Netback	58.33	72.43	61.07	54.47	42.72
Natural Gas Liquids — United States ($/bbl)					
Price	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	4.28	6.12	1.95	4.71	4.56
Transportation and selling	0.01	—	0.01	0.01	0.01
Netback	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids — Total ($/bbl)					
Price	59.61	73.42	61.31	55.33	45.66
Production and mineral taxes	2.36	3.30	1.13	2.59	2.43
Transportation and selling	0.46	0.44	0.76	0.34	0.26
Netback	56.79	69.68	59.42	52.40	42.97
Crude Oil — Light and Medium ($/bbl)					
Price	58.12	71.48	61.18	53.36	46.40
Production and mineral taxes	2.11	2.20	1.89	2.19	2.14
Transportation and selling	1.41	1.30	1.53	1.36	1.43
Operating	9.72	11.09	9.51	9.28	9.00
Netback	44.88	56.89	48.25	40.53	33.83

	Per-Unit Results — 2007				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/bbl)					
Price	50.76	59.93	54.68	47.02	41.42
Production and mineral taxes	1.09	1.12	1.01	1.16	1.06
Transportation and selling	1.32	1.23	1.47	1.31	1.27
Operating	9.03	10.52	8.68	8.85	8.06
Netback	39.32	47.06	43.52	35.70	31.03
Crude Oil — Heavy — Foster Creek/Christina Lake ($/bbl)					
Price	40.14	45.58	42.86	39.40	33.28
Production and mineral taxes	—	—	—	—	—
Transportation and selling	2.88	2.75	2.10	3.62	3.07
Operating(1,2)	14.46	14.05	12.55	14.02	17.12
Netback	22.80	28.78	28.21	21.76	13.09
Crude Oil — Total ($/bbl)					
Price	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	0.79	0.83	0.74	0.84	0.77
Transportation and selling	1.74	1.62	1.64	1.94	1.75
Operating	10.49	11.43	9.72	10.27	10.54
Netback	34.88	42.35	39.40	31.87	26.13
Total Liquids — Canada ($/bbl)					
Price	48.92	57.92	52.50	45.83	39.50
Production and mineral taxes	0.72	0.74	0.66	0.76	0.70
Transportation and selling	1.68	1.56	1.66	1.84	1.67
Operating	9.47	10.20	8.78	9.29	9.60
Netback	37.05	45.42	41.40	33.94	27.53
Total Liquids ($/bbl)					
Price	50.05	59.60	53.37	46.81	40.25
Production and mineral taxes	1.08	1.32	0.81	1.16	1.04
Transportation and selling	1.51	1.39	1.47	1.65	1.51
Operating	8.57	9.19	7.87	8.41	8.81
Netback	38.89	47.70	43.22	35.59	28.89
Total ($/Mcfe)					
Price	6.35	6.57	5.80	6.65	6.40
Production and mineral taxes	0.18	0.15	0.19	0.15	0.24
Transportation and selling	0.42	0.42	0.41	0.43	0.42
Operating(3)	0.93	1.02	0.83	0.93	0.95
Netback	4.82	4.98	4.37	5.14	4.79

Notes:

(1) First quarter operating costs include a prior year under accrual of approximately $1.82/bbl.

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

(3) Year-to-date operating costs include costs related to long-term incentives of $0.05/Mcfe.

	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 ($/Mcf)					
Price	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	0.24	0.21	0.21	0.13	0.41
Transportation and selling	0.42	0.42	0.44	0.40	0.40
Operating	0.74	0.77	0.71	0.74	0.74
Netback	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids — Canada ($/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 ($/bbl)					
Price	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	4.19	4.62	4.42	2.60	5.18
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids — Total ($/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 ($/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

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/bbl)					
Price	44.83	37.65	51.37	55.58	35.39
Production and mineral taxes	1.11	1.11	1.14	1.28	0.92
Transportation and selling	0.91	0.60	1.27	0.76	1.00
Operating	7.69	8.59	8.73	6.84	6.67
Netback	35.12	27.35	40.23	46.70	26.80
Crude Oil — Heavy — Foster Creek/Christina Lake ($/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 ($/bbl)					
Price	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	0.77	0.74	0.81	0.88	0.66
Transportation and selling	1.40	1.11	1.74	1.54	1.24
Operating	9.09	10.05	10.20	8.34	7.82
Netback	30.57	25.04	35.99	40.86	21.04
Total Liquids — Canada ($/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
Total Liquids ($/bbl)					
Price	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	0.99	0.99	1.05	0.96	0.96
Transportation and selling	1.24	0.98	1.52	1.35	1.10
Operating	7.66	8.47	8.58	7.01	6.64
Netback	33.82	28.25	39.22	43.12	25.17
Total ($/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 ($/Mcf)					
Price	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	0.34	0.48	0.32	0.28	0.27
Transportation and selling	0.40	0.39	0.41	0.38	0.40
Operating	0.62	0.68	0.64	0.58	0.58
Netback	6.10	8.74	5.92	5.01	4.56
Natural Gas Liquids — Canada ($/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 ($/bbl)					
Price	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	4.86	5.42	5.46	4.37	4.20
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids — Total ($/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 ($/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

	Per-Unit Results — 2005				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/bbl)					
Price	38.49	40.43	49.44	33.06	31.71
Production and mineral taxes	0.79	0.93	0.65	0.86	0.71
Transportation and selling	1.08	0.95	1.12	0.89	1.38
Operating	5.90	6.04	6.15	5.58	5.86
Netback	30.72	32.51	41.52	25.73	23.76
Crude Oil — Heavy — Foster Creek/Christina Lake ($/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 — Total ($/bbl)					
Price	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	0.58	0.66	0.48	0.66	0.53
Transportation and selling	1.20	1.12	1.15	1.15	1.39
Operating	7.23	7.79	7.35	7.02	6.74
Netback	25.14	24.84	36.18	21.00	18.94
Total Liquids — Canada ($/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
Total Liquids ($/bbl)					
Price	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	0.91	0.99	0.91	0.92	0.83
Transportation and selling	1.04	0.98	0.99	1.00	1.18
Operating	6.04	6.56	6.08	5.91	5.61
Netback	28.18	28.63	38.18	23.97	22.15
Total ($/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.

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

	2007				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	1.33	1.49	1.65	1.24	0.92
Liquids ($/bbl)	(3.05)	(8.76)	(4.36)	(1.34)	2.34
Total ($/Mcfe)	0.99	0.96	1.21	0.96	0.82

	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)

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:											
2007:											
Canada	120	96	7	6	—	—	127	102	180	307	102
United States	2	2	—	—	—	—	2	2	—	2	2
Other	—	—	—	—	4	3	4	3	—	4	3
Total	122	98	7	6	4	3	133	107	180	313	107
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
Discontinued Operations:											
Ecuador — 2005	—	—	2	1	3	2	5	3	—	5	3

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:											
2007:											
Canada	3,749	3,542	236	185	11	8	3,996	3,735	834	4,830	3,735
United States	809	641	—	—	1	1	810	642	102	912	642
Total	4,558	4,183	236	185	12	9	4,806	4,377	936	5,742	4,377
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
Discontinued Operations:											
Ecuador — 2006	—	—	7	6	1	1	8	7	—	8	7
Ecuador — 2005	—	—	28	15	3	1	31	16	—	31	16

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, 2007, EnCana was in the process of drilling 25 gross wells (17 net wells) in Canada, 64 gross wells (49 net wells) in the United States and two gross wells (one net 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, 2007.

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	38,950	36,824	3,928	3,486	42,878	40,310
British Columbia	2,166	1,962	19	13	2,185	1,975
Saskatchewan	490	455	1,283	568	1,773	1,023
Manitoba	—	—	1	1	1	1
Total Canada	41,606	39,241	5,231	4,068	46,837	43,309
Colorado	4,007	3,507	—	—	4,007	3,507
Texas	1,777	1,119	8	4	1,785	1,123
Wyoming	1,903	1,307	—	—	1,903	1,307
Utah	43	39	—	—	43	39
Louisiana	5	3	—	—	5	3
Kansas	1	1	—	—	1	1
Montana	1	1	—	—	1	1
Total United States	7,737	5,977	8	4	7,745	5,981
Total	49,343	45,218	5,239	4,072	54,582	49,290

Notes:

(1) EnCana has varying royalty interests in 15,003 natural gas wells and 9,708 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 32,070 gross natural gas wells (30,501 net wells) and 1,437 gross crude oil wells (1,247 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2007.

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	— Fee	4,522	4,522	2,595	2,595	7,117	7,117
	— Crown	4,202	3,269	4,809	3,745	9,011	7,014
	— Freehold	253	155	187	154	440	309
		8,977	7,946	7,591	6,494	16,568	14,440
British Columbia	— Crown	1,118	958	4,144	3,398	5,262	4,356
	— Freehold	—	—	7	—	7	—
		1,118	958	4,151	3,398	5,269	4,356
Saskatchewan	— Fee	61	61	449	449	510	510
	— Crown	134	113	477	412	611	525
	— Freehold	15	11	32	30	47	41
		210	185	958	891	1,168	1,076
Manitoba	— Fee	3	3	261	261	264	264
Newfoundland and Labrador	— Crown	—	—	35	2	35	2
Nova Scotia	— Crown	—	—	498	175	498	175
Northwest Territories	— Crown	—	—	45	11	45	11
Total Canada		10,308	9,092	13,539	11,232	23,847	20,324

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	— Federal/State Lands	199	185	720	664	919	849
	— Freehold	111	105	173	159	284	264
	— Fee	3	3	30	30	33	33
		313	293	923	853	1,236	1,146
Washington	— Federal/State Lands	—	—	655	298	655	298
	— Freehold	—	—	223	98	223	98
		—	—	878	396	878	396
Texas	— Federal/State Lands	7	4	472	452	479	456
	— Freehold	217	156	997	772	1,214	928
	— Fee	—	—	4	2	4	2
		224	160	1,473	1,226	1,697	1,386
Wyoming	— Federal/State Lands	143	87	636	452	779	539
	— Freehold	26	19	47	23	73	42
		169	106	683	475	852	581
Other	— Federal/State Lands	8	7	331	192	339	199
	— Freehold	3	3	981	978	984	981
		11	10	1,312	1,170	1,323	1,180
Total United States		717	569	5,269	4,120	5,986	4,689
Qatar		—	—	2,161	1,080	2,161	1,080
Greenland		—	—	1,701	1,488	1,701	1,488
Brazil(7)		—	—	1,662	522	1,662	522
France		—	—	859	859	859	859
Azerbaijan		—	—	346	17	346	17
Australia		—	—	104	40	104	40
Total International		—	—	6,833	4,006	6,833	4,006
Total		11,025	9,661	25,641	19,358	36,666	29,019

Notes:

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

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. 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 September 2007, EnCana agreed to sell its remaining interests in Brazil. The sale is subject to closing conditions and regulatory approvals, which are expected to be completed in the first half of 2008.

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. 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 2007 and 2006.

	2007	2006
	($ millions)	
Capital		
Canada	3,330	3,352
United States	1,919	2,061
Other	106	106
Integrated Oil	580	632
Market Optimization	6	44
Corporate(1)	94	74
Capital from Continuing Operations	6,035	6,269
Acquisitions		
Property		
Canada	75	11
United States(2)	2,613	284
Other	—	15
Integrated Oil	14	21
Divestitures		
Property		
Canada	(54)	(59)
United States	(10)	(19)
Other(3)	(149)	—
Corporate(4)	(57)	—
Corporate		
Market Optimization	—	(244)
Other(5)	(211)	(367)
Net Acquisition and Divestiture Activity from Continuing Operations	2,221	(358)
Discontinued Operations		
Ecuador	—	(1,116)
Midstream	—	(1,531)
Net Capital Investment	8,256	3,264

Notes:

(1) Includes capital expenditures on The Bow office project of $52 million in 2007.

(2) All the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in East Texas were acquired on November 20, 2007.

(3) Consists primarily of the sale of its Mackenzie Delta assets which was completed on May 30, 2007 and the sale of Australia assets which was completed on August 15, 2007.

(4) Sale of EnCana's office building project assets, The Bow, was completed on February 9, 2007.

(5) Sale of interests in Chad was completed on January 12, 2007, the sale of interests in Oman was completed on November 28, 2007 and the sale of shares of EnCanBrasil Limitada was completed on August 16, 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 20 to EnCana's audited consolidated financial statements for the year ended December 31, 2007.

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 2007, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2008. 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 $7.4 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. Coordination and oversight of the Policy resides with the Environment, Health, Safety and Security Group within Corporate Relations.

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.

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.

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 as well as the corporate responsibility website which allows people to write to the Corporation about non-financial issues of concern; (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 and guidelines for correct behaviors with respect to the acceptance of gifts and conflicts of interest. 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, 2007, EnCana employed 5,285 full time equivalent ("FTE") employees as set forth in the following table.

	FTE Employees
Canada, United States and Other	4,048
Integrated Oil	665
Market Optimization	77
Corporate	495
Total	5,285

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

Foreign Operations

As at December 31, 2007, all of EnCana's reserves and 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.

DIRECTORS AND OFFICERS

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

Directors

Name and Municipality of Residence	Director Since[13]	Principal Occupation
RALPH S. CUNNINGHAM[2,3] .... Houston, Texas, United States	2003	President & Chief Executive Officer EPE Holdings 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)*
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. *(Private sustainable energy development consulting company)*

Name and Municipality of Residence	Director Since(13)	Principal Occupation
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)*
ALLAN P. SAWIN(1,3) .... Edmonton, Alberta, Canada	2007	President Bear Investments Inc. *(Private investment company)*
DENNIS A. SHARP(2,4) .... Calgary, Alberta, Canada & Montreal, Quebec, Canada	1998	Chairman UTS Energy Corporation *(Oilsands company)*
JAMES M. STANFORD, O.C.(1,3,6) .... Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Private investment management)*
WAYNE G. THOMSON(2,6) .... Calgary, Alberta, Canada	2007	President Virgin Resources Limited *(Private international oil & gas exploration company)*
CLAYTON H. WOITAS(12) .... Calgary, Alberta, Canada	2008	Chairman & Chief Executive Officer Range Royalty Management Ltd. *(Private oil & gas 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) Mr. Woitas was appointed to the Board effective January 1, 2008. Committee appointments will be reviewed in April 2008.

(13) 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 16 directors of the Corporation. With the exception of Mr. Woitas, who was appointed to the Board effective January 1, 2008, all of the current directors were appointed at the last annual meeting of shareholders held on April 25, 2007. At the next annual meeting, shareholders will be asked to elect as directors the 14 individuals listed in the above table, with the exception of Mr. McCready who is not standing for re-election and Mr. Sharp who is retiring from the Board. 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 nominees 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 Calgary, Alberta, Canada	Executive Vice-President *(President, Integrated Oil Division)*
SHERRI A. BRILLON 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 Calgary, Alberta, Canada	Executive Vice-President, Corporate Communications
R. WILLIAM OLIVER Calgary, Alberta, Canada	Executive Vice-President, Business Development *(President, Midstream & Marketing Division)*
GERARD J. PROTTI Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations *(President, Offshore & International Division)*
IVOR M. RUSTE(1) Calgary, Alberta, Canada	Executive Vice-President & Chief Risk Officer
DONALD T. SWYSTUN 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)*

Note:

(1) Ivor M. Ruste (formerly Vice-President, Finance, Integrated Oil Division) was appointed Executive Vice-President & Chief Risk Officer of EnCana effective January 1, 2008.

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 has been, since August 1, 2007, a director and President and Chief Executive Officer of EPE Holdings LLC, the sole general partner of Enterprise GP Holdings L.P. (a publicly traded midstream energy holding company). From February 13, 2006 until July 31, 2007, he served as Group Executive Vice President and Chief Operating Officer and, from June 30, 2007 to July 31, 2007, also served as Interim President and Chief Executive Officer of Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners L.P. (a publicly traded midstream energy company). He was a director and Chairman of the Board of Texas Eastern Products Pipeline Company, LLC from March 2005 until November 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.

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. Ruste joined EnCana on May 1, 2006 as Vice-President, Finance of the Corporate Finance Group. He was appointed Vice-President, Finance for the Integrated Oil Division effective January 1, 2007 and was appointed Executive Vice-President & Chief Risk Officer effective January 1, 2008. From February 2003 to April 2006, he was a partner and the Office Managing Partner for the Edmonton, Alberta office of KPMG LLP, as well as the Alberta Region Managing Partner for KPMG LLP. During this period, he was also a member of the Board of Directors of KPMG Canada and, from December 2003 to March 2006, he was Vice Chair of the Board of Directors for KPMG Canada.

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.

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

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 was President and a director of Airborne Pollution Control Inc. from 2001 to 2003.

Mr. Woitas was appointed to the EnCana Board effective January 1, 2008. Currently, Mr. Woitas is Chairman and Chief Executive Officer of Range Royalty Management Ltd., a private company which is focused on acquiring royalty interests in Western Canadian oil and natural gas production. He was founder, Chairman, and President and Chief Executive Officer of privately held Profico Energy Management Ltd. (January 2000 to June 2006), a company focused on natural gas exploration and production in western Canada.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 13, 2008, directly or indirectly, or exercised control or direction over an aggregate of 954,259 Common Shares representing 0.13 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 4,672,518 additional Common Shares.

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee consists of six members, all of 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 Master 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), as well as 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 (Canadian property and casualty insurer) and its related companies, The Wawanesa Life Insurance Company and its U.S. subsidiary, 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 Chairman and a director of Petaquilla Copper Ltd. (a public mining company) 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 Master 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.

Allan P. Sawin

Mr. Sawin holds a Bachelor of Commerce (University of Alberta) and a designation as a Chartered Accountant (Alberta). He is President of Bear Investments Inc. (private investment company). From 1990 until their sale to CCS Income Trust in May 2006, Mr. Sawin was President, director and part owner of Grizzly Well Servicing Inc. and related companies (private oilfield service companies operating drilling and service rigs in western Canada). From 1995 to 2003, he also served as a director and member of the Audit Committee of NQL Drilling Tools Inc. while it was a public company listed on the Toronto Stock Exchange.

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 both OPTI Canada Inc. (oilsands development and upgrading company) and NOVA Chemicals Corporation (commodity chemical company). He was Chairman of the Audit Committee of Inco Limited from April 2002 until August 2005 when he retired from the Board. Mr. Stanford was 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 2007 and 2006.

($ thousands)	2007	2006
Audit Fees(1)	4,038	3,762
Audit-Related Fees(2)	153	401
Tax Fees(3)	847	1,215
All Other Fees(4)	35	34
Total	5,073	5,412

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 2007 and 2006, 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 2007 and 2006, 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 2007 and 2006, 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 2006 or 2007.

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, 2007, there were approximately 753 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 2007 annual and special meeting of shareholders and must be reconfirmed at every third annual meeting thereafter until it expires on July 30, 2011.

Preferred Shares

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

CREDIT RATINGS

The following table outlines the ratings of the Corporation's debt as of December 31, 2007.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")
Senior Unsecured/Long-Term Rating	A −	Baa2	A (low)
Commercial Paper/Short-Term Rating	A-1 (low)	P-2	R-1 (low)
Outlook	Stable	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. 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 2007.

	Toronto Stock Exchange Share Price Trading Range				New York Stock Exchange Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	(C$ per share)			(millions)	($ per share)			(millions)
2007								
January	57.89	51.55	56.45	68.2	49.01	42.38	48.03	64.8
February	58.25	54.77	56.85	44.6	49.86	47.19	48.57	44.2
March	59.65	53.67	58.40	55.3	51.49	45.87	50.63	54.2
April	61.84	58.08	58.10	42.4	54.99	50.58	52.45	45.0
May	68.65	57.61	65.51	52.7	63.21	51.79	61.40	65.6
June	71.21	64.17	65.52	65.7	66.87	59.88	61.45	56.1
July	67.99	62.20	65.30	51.7	65.18	59.22	60.98	57.5
August	66.43	59.33	61.89	47.8	63.13	55.13	58.50	64.7
September	65.10	60.66	61.50	40.7	64.16	58.33	61.85	39.0
October	66.10	60.89	66.10	47.8	69.89	60.86	69.70	56.2
November	69.47	63.67	64.90	51.0	75.85	63.82	65.25	65.4
December	69.59	64.77	67.50	33.7	69.59	64.03	67.96	36.8

In November 2007, 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 as at October 31, 2007. 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 2008, EnCana purchased approximately 3.0 million shares under the program for approximately $191 million.

In 2007, EnCana purchased approximately 38.9 million shares under the program for an average price of $52.05 for approximately $2.0 billion.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. At the beginning of 2005, 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). In the first quarter of 2007, EnCana increased its dividend by 100 percent to $0.80 per share annually ($0.20 per share quarterly). EnCana's Board of Directors has declared a quarterly dividend of $0.40 per share payable on March 31, 2008 to common shareholders of record on March 14, 2008, 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 (including liquefied natural gas). 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 represent 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, including with respect to royalty payments, 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.

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases there are few technical details regarding the implementation and coordination of these plans to regulate emissions. Additionally, it is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

As these federal and regional programs are 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 emissions legislation.

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. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") for $20 million 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.

The Corporation and WD intend to vigorously defend against the outstanding claims; however, the Corporation cannot predict the outcome of these proceedings or any future proceedings against EnCana, whether these proceedings 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:	In the United States:
CIBC Mellon Trust Company	BNY Mellon Shareowner Services
P.O Box 7010	480 Washington Blvd
Adelaide Street Postal Station	Jersey City, NJ
Toronto, ON M5C 2W9	07310
Tel: 1-800-387-0825	Tel: 1-800-387-0825
Website: www.cibcmellon.com/investorinquiry	Website: www.cibcmellon.com/investorinquiry

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, 2007. 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 22, 2008 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, 2007.

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, 2007. The reserves data consist of the following:

   (i) estimated proved oil and gas reserves quantities as at December 31, 2007 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, 2007:

Evaluator and Preparation Date of Report	Reserves Location	Estimated Proved Reserves Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax, 10% discount rate
		Gas	Liquids	
		(Bcf)	(MMbbl)	(US$MM)
McDaniel & Associates Consultants Ltd. January 31, 2008	Canada	4,156	772	19,687
GLJ Petroleum Consultants Ltd. January 30, 2008	Canada	3,136	97	9,501
Netherland, Sewell & Associates, Inc. January 29, 2008	United States	4,450	54	10,425
DeGolyer and MacNaughton January 18, 2008	United States	1,558	4	2,875
Totals		13,300	927	42,488

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. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

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 12, 2008

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, 2007 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 12, 2008 (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.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) Randall K. Eresman
President & Chief Executive Officer

(signed) Sherri A. Brillon
Executive Vice-President,
Strategic Planning & Portfolio Management

(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 13, 2008

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.