ENCANA™

ANNUAL INFORMATION FORM

February 20, 2009

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation (“EnCana” or the “Corporation”) for the year ended December 31, 2008. 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 “US$” are to U.S. dollars and all references to “C$” 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.

TABLE OF CONTENTS

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: the proposed arrangement transaction and expected future attributes of EnCana and Cenovus Energy Inc. following such transaction, bitumen strategy and the benefits of this strategy, drilling and development 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, the anticipated capacities of and the timing of capacity expansions for the Wood River refinery and the capital expenditures for such expansions, anticipated capacity for expansion of the Steeprock natural gas plant, reserves estimates, the level of expenditures for compliance with environmental regulations, including estimates of potential costs of carbon, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and divestiture plans and net cash flows.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other things contemplated by the forward-looking statements will not occur. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the assumptions, 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: risks associated with the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the proposed arrangement transaction (including regulatory and shareholder approvals), the risk that any applicable condition of the proposed arrangement transaction may not be satisfied, volatility of and assumptions regarding oil and natural gas prices as well as refined product 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, and the application thereof to the business of EnCana and Cenovus Energy Inc. after the proposed arrangement transaction, 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 assumptions, risks and uncertainties described from time to time in EnCana's reports and filings with the Canadian securities authorities and the U.S. 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. Forward-looking statements respecting the proposed arrangement transaction are based upon the assumption that financial and other markets will stabilize. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Corporation in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

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 the 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 current 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 U.S. 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").

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, 2008. 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, 2008.

Subsidiaries & Partnerships	Percentage Owned[1]	Jurisdiction of Incorporation, Continuance or Formation
EnCana Oil & Gas Partnership	100	Alberta
EnCana USA Holdings	100	Delaware
3080763 Nova Scotia Company	100	Nova Scotia
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Marketing (USA) Inc.	100	Delaware
FCCL Oil Sands Partnership	50	Alberta
EnCana Downstream Holdings ULC	100	Alberta
EnCana US Refinery Holdings	100	Delaware
WRB Refining LLC	50	Delaware
EnCana US Refineries, LLC	100	Delaware
EnCana USA Investment Holdings	100	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, 2008.

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 NGLs, 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 U.S. All of EnCana's proved reserves and production come from North America.

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.

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 allows EnCana to participate in the North American refining industry.

EnCana is organized into Operating Divisions and Corporate Groups. The Operating Divisions are:

- Canadian Plains Division, which includes natural gas production assets in southern Alberta and southern Saskatchewan as well as crude oil development and production assets in Alberta and Saskatchewan. Three key resource plays are located in the Division: (i) Shallow Gas in southeast Alberta and Saskatchewan; (ii) Pelican Lake in northeast Alberta; and (iii) Weyburn in Saskatchewan;
- Canadian Foothills Division, which includes natural gas development and production assets located in Alberta and British Columbia and the management of the Deep Panuke natural gas project offshore Nova Scotia. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia; (ii) Cutbank Ridge on the Alberta and British Columbia border; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in Alberta;
- USA Division, which includes the natural gas development and production assets located in the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) East Texas; and (iv) Fort Worth; and
- Integrated Oil Division, which includes all of the Canadian upstream and U.S. downstream assets within the integrated oil business with ConocoPhillips, as well as other bitumen interests and the Athabasca natural gas assets. Two key crude oil resource plays are located in the Integrated Oil Division: (i) Foster Creek; and (ii) Christina Lake.

For 2008 financial reporting purposes, EnCana's reportable segments are: (i) Canada; (ii) USA; (iii) Downstream Refining; (iv) Market Optimization; and (v) Corporate and Other. The Canada reportable segment comprises the Canadian Plains Division, the Canadian Foothills Division and the Canadian upstream operations of the Integrated Oil Division. Market Optimization activities are managed by EnCana's Business Development, Canadian Gas Marketing and Power Corporate Group and by divisional marketing groups. Market Optimization is focused on enhancing the netback price of the Corporation's proprietary production. Market Optimization activities include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

On May 11, 2008, EnCana announced its plans to split into two independent energy companies — one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the "Arrangement") would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") (prior working name "IOCo") and EnCana Corporation (prior working name "GasCo"). Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held. On October 15, 2008, EnCana announced that the proposed Arrangement would be delayed until financial markets regain stability.

EnCana's operating divisions, post-Arrangement, would include Canadian Foothills and USA. Cenovus' operating divisions, post-Arrangement, would include Canadian Plains and Integrated Oil.

The following describes the significant events in the development of EnCana's business over the last three years. In this section, all divestiture proceeds are provided on a before-tax basis unless otherwise noted.

2008 Projects:

- In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. EnCana's 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation by 2011. The expansion is expected to increase crude oil refining capacity by 50,000 barrels per day to approximately 356,000 barrels per day (on a 100 percent basis) and is expected to more than double heavy crude oil refining capacity to approximately 240,000 barrels per day.

2008 Acquisitions:

- In 2008, EnCana acquired, in several transactions, certain land and mineral interests in the Haynesville Shale in Louisiana and Texas for approximately $1,010 million, net to EnCana. These acquisitions increased EnCana's land position to approximately 435,000 net acres, including approximately 63,000 net mineral acres. Of these transactions, the most significant was the purchase made on July 23, 2008, when EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million which reduced EnCana's total share of the purchase price to approximately $300 million.

2008 Divestitures:

- In 2008, EnCana completed the divestiture of mature, non-core conventional oil and natural gas assets for proceeds of approximately $39 million in the Canadian Plains Division, $400 million in the Canadian Foothills Division and $251 million in the USA Division.
- In September 2008, EnCana completed the sale of all its remaining interests in Brazil for net proceeds of approximately $164 million, before closing adjustments, resulting in an after-tax gain on sale of approximately $99 million. EnCana's Brazil interests included ten offshore exploration blocks.
- In 2008, EnCana completed the sale of all of its interests in France and withdrew from Qatar.

2007 Projects:

- In November 2005, EnCana announced plans to examine a number of proposals from other companies which were interested in participating in the development of EnCana's bitumen assets. In October 2006, EnCana announced it had entered into agreements with ConocoPhillips to create equally owned integrated oil business consisting of upstream and downstream assets. The integrated oil business provides greater certainty of execution for EnCana's in-situ bitumen projects and allows EnCana to participate in the North American refining industry.

  The creation of this business was completed on January 3, 2007. It comprises 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 to shore by subsea pipeline and EnCana expects to transport this natural gas via the Maritimes & Northeast Pipeline to a delivery point in eastern Canada.

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 brought EnCana's interest in the Amoruso field to 100 percent and added an additional 75 million cubic feet per day of natural gas production in 2007.

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.

2006 Acquisitions:

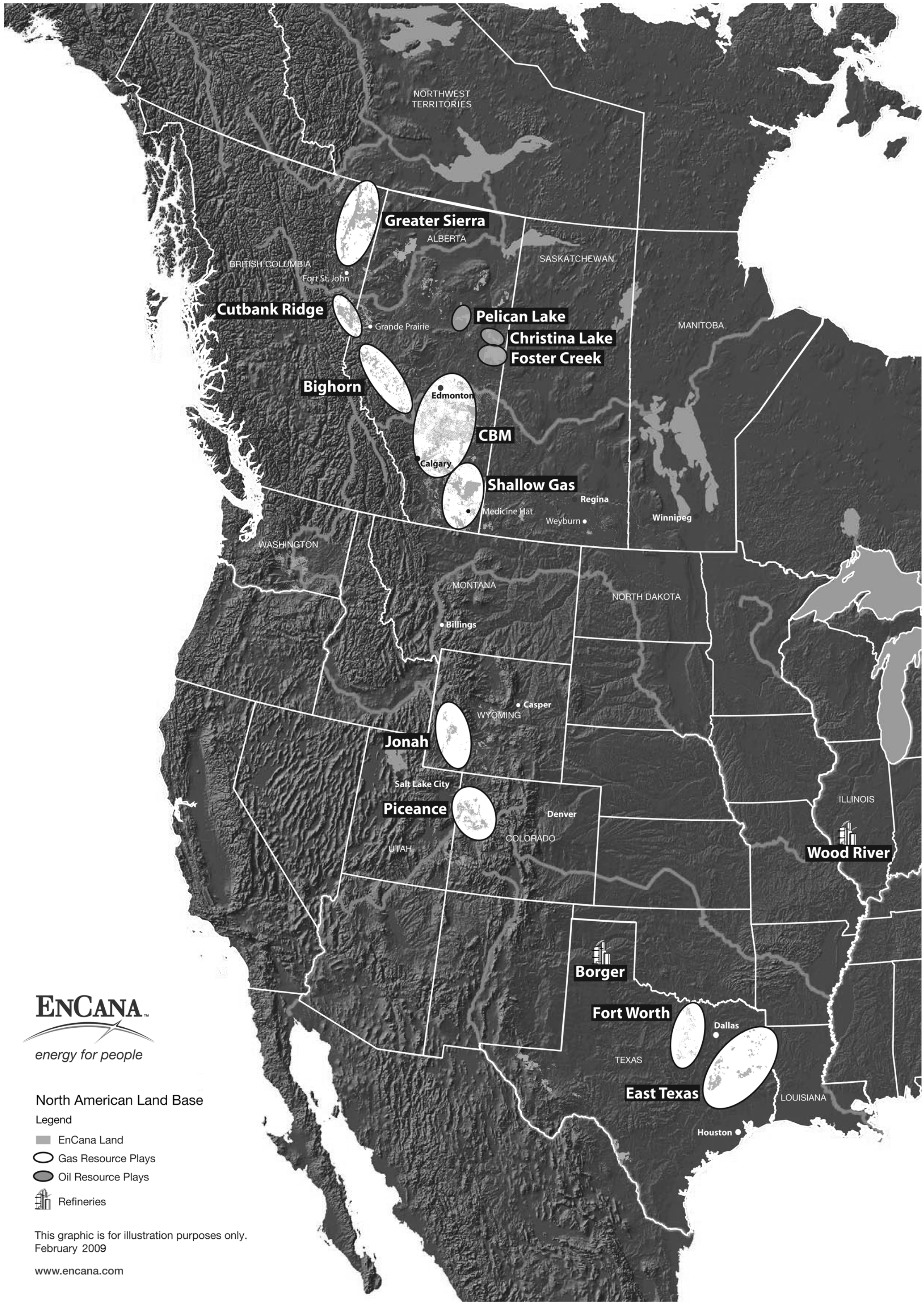
- In June 2006, EnCana increased its working interest in the Deep Bossier play in East Texas from 30 percent to 50 percent and purchased an additional 7,600 net acres in Robertson County for approximately $250 million. The transaction resulted in additional production of approximately 4.3 million cubic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

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 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.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2008. 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. All of EnCana's proved reserves and production come from North America.

At December 31, 2008, EnCana had net proved reserves of approximately 13.7 trillion cubic feet of natural gas and 1.0 billion barrels of crude oil, bitumen and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 63 percent of total natural gas reserves, approximately 72 percent of crude oil and NGLs reserves excluding bitumen and approximately 19 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 21.0 million gross acres (18.3 million net acres, of which approximately 9.3 million net acres are undeveloped). The mineral rights on approximately 41 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 2008, EnCana had capital investment in western Canada of approximately $3,737 million and drilled approximately 2,578 net wells.

In the U.S., EnCana's landholdings are approximately 5.4 million gross acres (4.4 million net acres, of which approximately 3.9 million net acres are undeveloped), with the majority in Texas, Colorado, Wyoming and Louisiana. In 2008, EnCana had capital investment of approximately $2,615 million, not including refineries, and drilled approximately 750 net wells within the USA Division.

The following narrative describes EnCana's operations in greater detail.

Canadian Plains Division

The Canadian Plains Division encompasses legacy natural gas production activities in southern Alberta and southern Saskatchewan as well as crude oil development and production activities in Alberta and Saskatchewan. Three key resource plays are located in the Canadian Plains Division: (i) Shallow Gas; (ii) Pelican Lake; and (iii) Weyburn. The Shallow Gas key resource play is contained within the Suffield, Brooks North and Langevin areas.

In 2008, the Canadian Plains Division had capital investment of approximately $847 million and drilled approximately 1,476 net wells. Plans for 2009 include continued infill drilling, well recompletions and well optimizations as well as enhanced oil recovery initiatives and investment in facility infrastructure necessary for continued progression of development plans.

As at December 31, 2008, the Canadian Plains Division had an established land position of approximately 6.9 million gross acres (6.5 million net acres). Approximately 2.6 million gross acres (2.5 million net acres) are undeveloped. The mineral rights on approximately 48 percent of the total net acreage are owned in fee title by EnCana.

The following table summarizes landholdings for the Canadian Plains Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	924	910	70	69	994	979	98%
Brooks North	560	558	9	9	569	567	100%
Langevin	1,215	1,096	853	773	2,068	1,869	90%
Drumheller	363	351	16	13	379	364	96%
Pelican Lake	133	133	280	266	413	399	97%
Weyburn	95	83	393	386	488	469	96%
Other	973	909	1,013	934	1,986	1,843	93%
Canadian Plains Total	4,263	4,040	2,634	2,450	6,897	6,490	94%

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

Production (annual average)	Natural Gas (MMcf/d) 2008	2007	Crude Oil and NGLs (bbls/d) 2008	2007	Total Production (MMcfe/d) 2008	2007
Suffield	231	245	12,971	15,563	309	338
Brooks North	273	271	838	742	278	275
Langevin	203	219	9,111	9,542	258	277
Drumheller	93	97	2,276	2,190	107	110
Pelican Lake	1	1	21,975	23,253	132	141
Weyburn	—	—	14,056	14,774	84	89
Other	41	42	6,111	6,136	78	78
Canadian Plains Total	842	875	67,338	72,200	1,246	1,308

Note:

(1) The Shallow Gas key resource play, contained within the Suffield, Brooks North and Langevin areas, had 2008 average production of approximately 700 million cubic feet per day (726 million cubic feet per day in 2007). 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.

The following table summarizes EnCana's interests in producing wells in the Canadian Plains Division as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	9,989	9,971	725	725	10,714	10,696
Brooks North	7,123	7,018	53	53	7,176	7,071
Langevin	6,791	6,216	244	238	7,035	6,454
Drumheller	1,547	1,487	97	94	1,644	1,581
Pelican Lake	7	7	453	453	460	460
Weyburn	—	—	773	485	773	485
Other	1,177	1,153	660	622	1,837	1,775
Canadian Plains Total	26,634	25,852	3,005	2,670	29,639	28,522

Note:

(1) At December 31, 2008, the Shallow Gas key resource play had approximately 23,903 gross producing gas wells (23,205 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 in cooperation with the Canadian military according to guidelines established under agreements presently entered into with the Government of Canada. On October 6, 2008, an ERCB joint panel hearing as part of the *Canadian Environmental Assessment Act* was commenced in connection with EnCana's ongoing application to continue shallow gas infill drilling in the National Wildlife Area. The hearing was completed in late October. On January 27, 2009, the joint panel released a report in respect of its findings. In its report, the joint panel concluded that this project could proceed provided two key pre-conditions were met. The first is that critical habitat assessments for certain specific species of plants and animals be finalized. The second is that the role of the Suffield Environmental Advisory Committee be clarified, and that this Committee be resourced adequately to provide proper regulatory oversight of the project. EnCana will now work with necessary interested parties to proceed to the next stage of this project.

In 2008, approximately 516 net wells were drilled in the Suffield area and production averaged approximately 231 million cubic feet per day of natural gas and approximately 12,971 barrels per day of crude oil.

Brooks North

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons and has begun development of the coals of the Cretaceous Belly River formation in the Brooks North area of southern Alberta. This area is another core area of the Shallow Gas key resource play and is largely composed of fee title lands. Development in the area focuses on infill drilling, recompletions and optimization of existing wells. In 2008, approximately 481 net wells were drilled in the area and production averaged approximately 273 million cubic feet per day of natural gas.

Langevin

EnCana produces shallow gas predominantly from the Upper Cretaceous formations in the Langevin area of southeast Alberta and southwest Saskatchewan and has begun development of the coals of the Cretaceous Belly River formation. Natural gas production in this area is from a mix of fee title and Crown lands and is included in the Shallow Gas key resource play. Crude oil production in the area is predominantly from fee title lands located in southern Alberta. Development of this area focuses on infill drilling, recompletions and optimization of existing wells. In 2008, approximately 271 net wells were drilled in the area and production averaged approximately 203 million cubic feet per day of natural gas and approximately 9,111 barrels per day of crude oil.

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 natural gas play, and is largely composed of fee title lands. In 2008, approximately 174 net wells were drilled in the area and production averaged approximately 93 million cubic feet per day of natural gas.

Pelican Lake

Pelican Lake is one of EnCana's key resource plays producing heavy crude oil from the Cretaceous Wabiskaw formation in northeast Alberta. Facility infrastructure expansion in this area was continued in 2008 to accommodate higher total fluid production volumes associated with its waterflood and polymer projects. The polymer flood program was expanded by 35 injection wells during 2008.

In addition to the heavy crude oil in the Wabiskaw formation, large deposits of bitumen have been identified in the Cretaceous Grand Rapids and the Devonian Grosmont formations in the Pelican Lake area which EnCana continues to evaluate.

EnCana 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.

In August 2008, EnCana entered into an agreement with Pembina Pipeline Corporation ("Pembina") to transport blended heavy oil from Utikuma, Alberta to Edmonton, Alberta via Pembina's pipeline with 100,000 barrels per day capacity. This pipeline will be used to transport heavy oil from EnCana's Pelican Lake property to crude oil markets. The parties also agreed to transport condensate, used as diluent for transporting heavy oil, from Whitecourt, Alberta to Utikuma, Alberta via a 22,000 barrel per day capacity pipeline. The initial term of the agreement is ten years from the in-service date, which is estimated to be in mid-2011.

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 is increasing ultimate recovery in the enhanced oil recovery area of the field with a carbon dioxide ("CO_2") miscible flood project. Weyburn is currently recognized as the world's largest CO_2 sequestration project. The CO_2 is pipelined directly to the Weyburn facility from a coal gasification project in North Dakota. The 2008 development program included an infill drilling program which resulted in 34 new gross wells in the unit, the addition of eight new CO_2 injection patterns and facilities related to pattern development. As at December 31, 2008, there were 46 patterns completed, with an additional eight awaiting CO_2 injection out of a current planned total of 75 patterns. In 2009, EnCana plans to focus on flood development with the roll out of additional CO_2 patterns along with CO_2 injector conversions, and waterflood pattern realignments.

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) CBM. The CBM key resource play (Horseshoe Canyon CBM and commingled shallow gas) is located within the Clearwater business unit. In addition, EnCana has established a leading land position in the emerging Horn River Devonian shale, located adjacent to the Greater Sierra key resource play. In late 2008, the management of the offshore Deep Panuke natural gas project in Atlantic Canada was transferred to the Canadian Foothills Division.

In 2008, the Canadian Foothills Division had capital investment in western Canada of approximately $2,234 million and drilled approximately 1,064 net wells.

As at December 31, 2008, the Canadian Foothills Division had an established land position in western Canada of approximately 12.1 million gross acres (10.2 million net acres); of these, approximately 6.8 million gross acres (5.8 million net acres) are undeveloped. The mineral rights on approximately 43 percent of the total net acreage are owned in fee title by EnCana.

The following table summarizes landholdings for the Canadian Foothills Division as at December 31, 2008.

Landholdings (thousands of acres)	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working Interest**
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Greater Sierra	641	599	1,718	1,428	2,359	2,027	86%
Cutbank Ridge	341	264	957	860	1,298	1,124	87%
Bighorn	304	179	509	324	813	503	62%
Clearwater	3,540	3,127	2,783	2,613	6,323	5,740	91%
Other	461	292	847	554	1,308	846	65%
Canadian Foothills Total(1)	5,287	4,461	6,814	5,779	12,101	10,240	85%

Note:

(1) Excluding offshore landholdings.

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)**	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**
Greater Sierra	220	211	1,044	852	226	216
Cutbank Ridge(1)	296	258	617	457	300	261
Bighorn(1)	167	126	3,734	2,123	189	139
Clearwater(2)	495	497	10,777	10,595	560	561
Other	122	163	3,808	4,245	145	188
Canadian Foothills Total	1,300	1,255	19,980	18,272	1,420	1,365

Notes:

(1) Key resource play production information for Cutbank Ridge and Bighorn has been restated to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.

(2) The CBM key resource play, located within the Clearwater area, had 2008 average production of approximately 304 million cubic feet per day (259 million cubic feet per day in 2007).

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	1,006	970	3	3	1,009	973
Cutbank Ridge(1)	693	599	16	2	709	601
Bighorn(1)	435	303	8	4	443	307
Clearwater(2)	8,976	8,188	151	109	9,127	8,297
Other	595	461	243	153	838	614
Canadian Foothills Total	11,705	10,521	421	271	12,126	10,792

Notes:

(1) Key resource play production information for Cutbank Ridge and Bighorn has been restated to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.

(2) At December 31, 2008, the CBM key resource play had approximately 5,426 gross producing gas wells (5,072 net gas wells).

The following describes the Canadian Foothills Division major producing areas or activities.

Greater Sierra

The Greater Sierra area in northeast British Columbia is one of EnCana's key natural gas resource plays. The primary focus in this area is on the continued development of the Devonian Jean Marie formation and the pilot commercial demonstration development of the Horn River Devonian Shale formation.

In 2008, EnCana drilled approximately 106 net natural gas wells in the area and production averaged approximately 220 million cubic feet per day of natural gas. Production has remained relatively constant over the past four years.

As at December 31, 2008, EnCana held an average 99 percent interest in 13 production facilities in the area that were capable of processing approximately 500 million cubic feet per day of natural gas. EnCana also held 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.

As at December 31, 2008, EnCana controlled approximately 436,000 undeveloped gross acres (260,000 net acres) in the emerging Devonian Shale formation of the Horn River Basin in northeast British Columbia. The shales in the basin (Muskwa, Otter Park and Evie) within EnCana's focus area are upwards of 500 feet thick. As at December 31, 2008, these shales were evaluated with 15 wells (five vertical and ten horizontal), nine of which have been placed on long-term production (one vertical and eight horizontal). In 2009, EnCana and its partner plan to drill a larger program of horizontal wells in the Two Island Lake area, and construct a compressor station and 24-inch raw gas transmission pipeline.

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 Montney, Cadomin, and Doig zones. The majority of EnCana's lands in this area were purchased in 2003. The Montney and Cadomin 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 2008, EnCana drilled approximately 82 net natural gas wells in the area and production averaged approximately 296 million cubic feet per day of natural gas.

EnCana holds approximately 731,000 net acres covering the unconventional deep basin Montney formation, with approximately 244,000 net acres located within EnCana's core development area near Dawson Creek, British Columbia. EnCana has tested the deep basin Montney play extensively over the last several years and, by applying advanced technology, has reduced overall development costs significantly, achieving a greater than 70 percent reduction in costs on a completed interval basis over the past two years.

EnCana's Steeprock plant had a capacity of approximately 70 million cubic feet per day at year-end 2007. An expansion was completed in July 2008 to bring total processing capacity to approximately 175 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 Resthaven, Kakwa, Wild River, Berland and Aurora. In 2008, EnCana drilled approximately 64 net wells in the area and production averaged approximately 167 million cubic feet per day of sweet natural gas.

EnCana has a working interest in a number of natural gas plants within Bighorn. The Resthaven plant, in which EnCana has a 60.8 percent working interest, has a capacity of approximately 100 million cubic feet per day. The Kakwa gas plant has a capacity of approximately 60 million cubic feet per day. EnCana owns 75 percent of this plant and has firm processing capacity for the remaining 25 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.

Clearwater

The Clearwater area extends from the U.S. border to central Alberta. The primary focus of Clearwater is the CBM key natural gas resource play; however, Clearwater is also responsible for the development of the Mannville CBM fairway, and deeper Cretaceous reservoirs. Within Clearwater, EnCana holds approximately 5.7 million net acres with approximately 2.1 million net acres on the Horseshoe Canyon trend. Approximately 77 percent of the total net acreage landholdings are owned in fee title. In 2008, EnCana drilled approximately 698 net CBM wells and production averaged approximately 304 million cubic feet per day of natural gas from the CBM key resource play.

Atlantic Canada

As at December 31, 2008, EnCana held an interest in approximately 76,000 gross acres (31,000 net acres) in Atlantic Canada, which includes Nova Scotia, Newfoundland and Labrador. EnCana operates five of its eight licenses in these areas and has an average working interest of approximately 40 percent.

EnCana is the operator of the Deep Panuke natural gas field, located offshore Nova Scotia, and owned substantially the entire Deep Panuke field at December 31, 2008, after acquiring all of the interests in one of the licenses making up the Deep Panuke field in August 2008. EnCana is currently moving forward with the development of the Deep Panuke natural gas project. Work has been progressing on budget and on schedule in anticipation of first production in the fourth quarter of 2010.

USA Division

EnCana's operations in the U.S. are focused on exploiting long-life unconventional natural gas formations in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado, the East Texas and Fort Worth basins in Texas, and the Haynesville Shale in Texas and Louisiana. The majority of the production in the U.S. is from the following four key resource plays: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth. The USA Division also has interests in natural gas gathering and processing assets, primarily in Colorado, Wyoming, Texas and Utah.

In 2008, the USA Division had capital investment of approximately $2,615 million and drilled approximately 750 net wells.

As at December 31, 2008, EnCana's landholdings in the U.S. were approximately 5.4 million gross acres (4.4 million net acres), of which approximately 4.7 million gross acres (3.9 million net acres) were undeveloped, with the majority in Texas, Colorado and Wyoming.

The following table summarizes landholdings for the USA Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Jonah	12	11	145	131	157	142	90%
Piceance	261	235	784	686	1,045	921	88%
East Texas	105	73	290	263	395	336	85%
Fort Worth	55	52	81	51	136	103	76%
Haynesville	15	13	585	422	600	435	73%
Maverick Basin	106	20	264	235	370	255	69%
Delaware Basin	4	2	731	598	735	600	82%
Other	157	154	1,794	1,479	1,951	1,633	84%
USA Total	715	560	4,674	3,865	5,389	4,425	82%

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)	
	2008	2007	2008	2007	2008	2007
Jonah	603	557	5,273	5,345	635	589
Piceance	385	348	2,513	2,755	400	364
East Texas	334	143	134	207	335	145
Fort Worth	142	124	500	497	145	127
Other	169	173	4,930	5,376	198	205
USA Total	1,633	1,345	13,350	14,180	1,713	1,430

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Jonah	655	587	—	—	655	587
Piceance	2,907	2,547	3	1	2,910	2,548
East Texas	739	430	6	3	745	433
Fort Worth	711	613	21	20	732	633
Other	2,233	1,473	16	10	2,249	1,483
USA Total	7,245	5,650	46	34	7,291	5,684

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. Historically, EnCana's operations have been conducted in the over-pressured core portion of the field. In 2008, EnCana commenced developing the adjacent normally pressured lands.

Within the over-pressured area, EnCana plans to drill the field to ten acre spacing, with higher densities in some areas. As at December 31, 2008, approximately 300 net ten acre locations remain, with approximately 255 additional net locations available. Outside the over-pressured area, EnCana owns approximately 55,000 gross acres, where 40 acre and possibly 20 acre drilling potential exists.

During 2008, EnCana drilled 151 net wells within the core area with 30 day initial production rates averaging 3.5 million to 4.5 million cubic feet per day and 24 net wells in the adjacent lands at initial rates averaging 0.8 million to 1.3 million cubic feet per day. During 2008, the Jonah field averaged approximately 603 million cubic feet per day of natural gas production.

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 2008, EnCana drilled approximately 328 net wells in the basin and net production of natural gas averaged approximately 385 million cubic feet per day.

In 2006 and 2007, EnCana finalized five agreements to jointly develop portions of the Piceance Basin. In 2008, EnCana finalized another two agreements to jointly develop additional portions of the Piceance Basin that encompassed approximately 28,867 net acres. For the period 2008 to 2011, it is expected that EnCana will drill approximately 336 net wells with third party funds. During 2008, EnCana drilled approximately 113 net wells with third party funds and its partners drilled approximately seven net wells.

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 in 2004 with the acquisition of Tom Brown, Inc. 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 2008, EnCana drilled approximately 78 net wells in the basin and production averaged approximately 334 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, EnCana has assembled a significant land position in the Barnett Shale play in this basin. EnCana is applying both horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. EnCana drilled approximately 83 net wells in the basin in 2008 and production averaged approximately 142 million cubic feet per day of natural gas.

Haynesville Shale

EnCana has established a land and resource position in the Haynesville Shale in Texas and Louisiana. EnCana acquired its first leases in 2005, drilled its first three vertical wells in 2006, and has continued to acquire land. In 2007, EnCana signed a 50/50 joint exploration agreement with an unrelated party. As at December 31, 2008, the companies had drilled eight vertical and six horizontal wells and are currently operating nine rigs in the area. EnCana and its joint venture partner are now drilling horizontal wells exclusively.

In 2008, EnCana increased its leased acreage in the Haynesville Shale play to approximately 435,000 net acres through a series of transactions totalling approximately $1,010 million. Included in this land position is approximately 63,000 net acres of mineral interests that were purchased by EnCana in July 2008 for approximately $300 million, net to EnCana.

Maverick Basin

EnCana holds approximately 264,000 undeveloped gross acres (235,000 net acres) in the Maverick Basin in southwest Texas. This acreage, acquired in September 2005, contains 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 from three to seven wells, with an option to drill more. EnCana's partner has elected to continue the joint venture agreement and has committed to drilling four additional horizontal wells in 2009.

Delaware Basin

EnCana holds approximately 731,000 undeveloped gross acres (598,000 net acres) in the Delaware Basin of West Texas. This acreage, acquired in September 2004, contains exploratory potential in the Barnett and Woodford Shale, plus multi-zone potential in the uphole section. In 2007, EnCana entered into a joint venture agreement to drill 12 wells, with an option to drill more. As at December 31, 2008, ten exploratory wells were drilled and completed, and two wells were still being drilled as of year end.

Gulf Coast Jurassic Trend

During 2007 and 2008, EnCana acquired a land position of approximately 470,000 net acres in several projects in the Gulf Coast Jurassic Trend located in Texas, Louisiana and Mississippi.

Gathering & Processing Facilities

EnCana owns and operates various natural gas gathering and processing facilities within the U.S. 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 approximately 794 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 550 kilometres of pipelines and a refrigeration facility with a capacity of approximately 70 million cubic feet per day. During 2008, two pipelines were sold for approximately $132 million.

Integrated Oil Division

The Integrated Oil Division includes all of the assets within the integrated oil business with ConocoPhillips, as well as other bitumen interests and the Athabasca natural gas assets. For 2008 financial reporting purposes, the Integrated Oil Division's Canadian upstream assets are included in the Canada reportable segment and the U.S. downstream refining assets are included in the Downstream Refining reportable segment.

The Integrated Oil Division contains two key crude oil resource plays: (i) Foster Creek; and (ii) Christina Lake. As at December 31, 2008, EnCana held bitumen rights of approximately 1,056,000 gross acres (761,000 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 2008, the Integrated Oil Division invested capital of approximately $1,134 million and drilled approximately 38 net wells.

The following table summarizes landholdings for the Integrated Oil Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Foster Creek	24	12	48	24	72	36	50%
Christina Lake	1	—	24	12	25	12	50%
Athabasca	538	461	383	312	921	773	84%
Borealis	—	—	37	37	37	37	100%
Other	35	16	942	687	977	703	72%
Integrated Oil Total	598	489	1,434	1,072	2,032	1,561	77%

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)	
	2008	2007	2008	2007	2008	2007
Foster Creek	—	—	25,947	24,262	156	146
Christina Lake	—	—	4,236	2,552	25	15
Athabasca	63	91	—	—	63	91
Other	—	—	2,729	2,688	16	16
Integrated Oil Total	63	91	32,912	29,502	260	268

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Foster Creek	—	—	114	57	114	57
Christina Lake	9	5	16	8	25	13
Athabasca	706	665	—	—	706	665
Other	2	1	20	17	22	18
Integrated Oil Total	717	671	150	82	867	753

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

Integrated Oil Business

On January 3, 2007, the creation of the integrated oil business with ConocoPhillips was completed. The integrated oil business includes Canadian upstream assets contributed by EnCana and U.S. downstream assets contributed by ConocoPhillips. The business comprises two 50/50 operating entities, one Canadian upstream entity managed by EnCana and one U.S. downstream enterprise managed by ConocoPhillips.

The upstream portion of the integrated oil business is currently conducted through the FCCL Oil Sands Partnership ("FCCL") which owns the Foster Creek and Christina Lake in-situ oil recovery projects. EnCana and ConocoPhillips each own 50 percent of FCCL. EnCana's wholly-owned subsidiary is the operating and managing partner of FCCL. The downstream portion of the integrated oil business is conducted through the 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 65 percent 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 composed of three EnCana and three ConocoPhillips representatives, with each company holding equal voting rights. The current plan of FCCL is to increase production capacity to approximately 218,000 barrels of bitumen per day with the completion of current expansion phases at Foster Creek and Christina Lake. The current plan of WRB is to refine approximately 135,000 barrels per day of bitumen equivalent to primarily motor fuels with the completion of the CORE project in 2011. As at December 31, 2008, WRB had processing capability to refine up to approximately 70,000 barrels per day of bitumen equivalent.

Foster Creek

Through its interest in FCCL, EnCana has a 50 percent interest in Foster Creek, a key crude oil resource play. 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 holds 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. An in-situ oil recovery project is currently being operated 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 production capacity of approximately 30,000 gross barrels of bitumen per day and increased production capacity at Foster Creek to approximately 60,000 gross barrels of bitumen per day. Further expansions are currently underway and are expected to increase production capacity to approximately 120,000 gross barrels of bitumen per day in 2009.

EnCana researches and develops technologies to increase recovery and decrease costs of extracting oil. One focus area is alternate methods of artificial lift where EnCana utilizes new pump designs that are expected to enable it to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital and operating costs. As at December 31, 2008, 83 wells were on electrical submersible pumps at Foster Creek, and EnCana expects to continue to utilize this technology on new SAGD wells. In addition, EnCana has successfully piloted another technology at Foster Creek whereby an additional production well is drilled between two producer well pairs to produce bitumen that is heated by proximity to a steam chamber, but is not recoverable by the adjacent production wells. A number of these "wedge wells" (patent pending) are on production and there are plans to complete and produce from additional wedge wells.

EnCana also focuses on reducing its reliance on natural gas for the generation of steam used in bitumen production operations. Two technologies using solvents have been piloted 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 process pilot project are being utilized during investigations into new production strategies for bitumen recovery. The Solvent Aided Process ("SAP") is discussed in the Christina Lake section below.

EnCana operates an 80 megawatt natural gas-fired cogeneration facility in conjunction with the SAGD operation at Foster Creek. The steam and power generated by the facility is presently being used within the SAGD operation and the excess power generated is being sold into the Alberta Power Pool grid.

Christina Lake

Through its interest in FCCL, EnCana has a 50 percent interest in a SAGD oil recovery project at Christina Lake, a key crude oil resource play. During 2008, EnCana completed an expansion that increased production capacity to approximately 18,000 gross barrels of bitumen per day. Further expansions are currently underway and are expected to increase production to approximately 98,000 gross barrels of bitumen per day.

At Christina Lake, EnCana is focusing on a number of innovations, including a pilot SAP program that was commenced in 2004. This process mixes a small amount of solvent with steam to enhance recovery. EnCana has completed testing the SAP technology on several wells associated with the initial demonstration project and has achieved promising results. An additional SAP pilot well is planned within the 2009 to 2010 timeframe. Business cases are being evaluated for the potential use of this technology in the Christina Lake development plan.

Another innovation was undertaken in 2007, whereby a remote water disposal system was utilized to successfully manage bottom water pressures and improve the steam-oil ratio.

Borger Refinery

Through its interest in WRB, EnCana has a 50 percent interest in the Borger refinery, located in Borger, Texas. As at December 31, 2008, the Borger refinery had a processing 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 heavy oil blends, 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.

Wood River Refinery

Through its interest in WRB, EnCana has a 50 percent interest in the Wood River refinery, located in Roxana, Illinois. As at December 31, 2008, the Wood River refinery had a processing 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 sulphur removal technology for the production of low-sulphur gasoline. In September 2008, regulatory approval was received to proceed with the CORE project at Wood River, which will increase crude oil refining capacity by approximately 50,000 barrels per day, coking capacity by approximately 65,000 barrels per day, more than double heavy crude oil refining capacity to approximately 240,000 barrels per day, increase the clean transportation fuels yield by approximately 10 percent to approximately 89 percent and will eliminate approximately 40,000 barrels per day of asphalt production. Capital expenditures for the CORE project are estimated at $3.6 billion ($1.8 billion net to EnCana) and the project is scheduled to be completed in 2011.

The following table summarizes the combined refineries' key operational results for the periods indicated.

Refinery Operations[(1)]	**2008**	**2007**
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	423	432
Crude Utilization	93%	96%
Refined Products (Mbbls/d)		
Gasoline	230	246
Distillates	139	128
Other	79	83
Total	448	457

Note:

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

Athabasca

EnCana produces natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeast Alberta and holds surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range that 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 2008, natural gas production was impacted by the September 2003, July 2004, September 2004 and July 2007 Energy Resource Conservation Board ("ERCB") decisions to shut-in McMurray, Wabiskaw 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 26 million cubic feet per day in 2008 (20 million cubic feet per day in 2007). The Alberta Government's Department of Energy is providing financial assistance in the form of a royalty credit, which is equal to approximately 50 percent of the cash flow lost as a result of the shut-in wells.

Borealis

EnCana holds 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 integrated oil business with ConocoPhillips. Approximately 198 delineation wells have been drilled in the greater Borealis area as at December 31, 2008. 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. EnCana continues to evaluate the greater Borealis area. In 2008, seven wells were drilled to test specific reservoir properties of the McMurray formation and to test for potential water disposal zones in support of the joint application. The use of nitrogen injection to displace top water was successfully tested as part of the program.

Market Optimization

Market Optimization activities are managed by EnCana's Business Development, Canadian Gas Marketing & Power Corporate Group and by divisional marketing groups. Market Optimization is focused on enhancing the netback price of the Corporation's proprietary production. Market Optimization activities 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.

EnCana seeks to mitigate the market risk associated with forecasted cash flows by entering into various risk management contracts relating to produced products. Details of those transactions related to EnCana's various risk management positions for natural gas, crude oil and power are found in Note 20 to EnCana's audited consolidated financial statements for the year ended December 31, 2008.

Natural Gas Marketing

In 2008, approximately 94 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 6 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 seeks to mitigate the market risk associated with forecasted cash flows by entering into various risk management contracts relating to produced natural gas. For 2009, after taking into account its risk management contracts, EnCana's natural gas sales price portfolio exposure consists of approximately 2.6 billion cubic feet per day for January to October 2009 at an average fixed NYMEX equivalent price of approximately $9.13 per thousand cubic feet with the remainder unhedged.

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (86,560 barrels per day in 2008 and 95,082 barrels per day in 2007). Crude oil sales are normally executed under spot, monthly evergreen and term 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. As part of a portfolio approach to its transportation and market needs, EnCana expects to increase its sales to the U.S. Gulf Coast in the future.

EnCana also has a founding position in the Western Canadian Select ("WCS") crude oil stream. Participation in WCS is important from the perspective of creating a transparent heavy oil benchmark, enhancing the liquidity of the heavy oil market and as a reference for Crown royalty determination.

In order to meet pipeline viscosity specifications, EnCana must blend certain of its heavy oil production with diluent. Security of supply is critical and EnCana has diversified sourcing of diluent since 2006 by obtaining supply both domestically and from offshore via the west coast of British Columbia.

EnCana markets blend oil on behalf of FCCL through an agency agreement (80,866 barrels per day in 2008 and 71,415 barrels per day in 2007). This agency agreement became effective on January 2, 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 operations 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 147 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

Since inception, 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. In 2008, 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 3 percent in 2008 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,966 billion cubic feet. Changes in the revisions and improved recovery category for natural gas reserves were negative at 18 billion cubic feet, or less than 1 percent of proved natural gas reserves at the beginning of 2008, primarily as a consequence of relatively low natural gas prices in the U.S. Rockies on December 31, 2008. Approximately two-thirds of extensions and discoveries were in Canada with the balance being in the U.S. Purchase and sale of reserves in place were not material.

In 2007 and 2006, natural gas reserves increased primarily from development and exploration drilling.

EnCana's crude oil and NGLs reserves increased approximately 8 percent at year-end 2008 in comparison to year-end 2007, largely as a result of positive revisions associated with the Corporation's interests in Foster Creek and Christina Lake.

As at December 31, 2007, EnCana's crude oil and NGLs reserves were approximately 18 percent lower than at 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 bookings 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 resulting from an almost two-fold increase in field prices relative to the prior year end.

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 2008 prices were as follows: crude oil (WTI) $44.60/bbl, (Edmonton Light) C$44.27/bbl, decreases of 54 percent and 53 percent from year-end 2007, respectively; Foster Creek field price C$30.39/bbl, a decrease of 39 percent from year-end 2007; natural gas (Henry Hub) $5.71/MMbtu, a decrease of 16 percent from year-end 2007; and natural gas (AECO) C$6.22/MMbtu, a decrease of 6 percent from year-end 2007.

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 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 same methodology was used at year-end 2008.

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[3]	Total
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[4]	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[4]	54.0	—	1,133.4
2007							
Beginning of year	7,028	5,390	12,418	1,079.4	54.0	—	1,133.4
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	0.0	—	0.2
Sale of reserves in place	(24)	(7)	(31)	(398.2)[5]	(0.0)	—	(398.2)
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
2008							
Beginning of year	7,292	6,008	13,300	868.9	58.3	—	927.2
Revisions and improved recovery	148	(166)	(18)	112.8	(3.6)	—	109.2
Extensions and discoveries	1,311	655	1,966	17.0	3.8	—	20.8
Purchase of reserves in place	32	7	39	0.2	0.0	—	0.2
Sale of reserves in place	(129)	(75)	(204)	(0.9)	(2.0)	—	(2.9)
Production	(807)	(598)	(1,405)	(44.0)	(4.9)	—	(48.9)
End of year	7,847	5,831	13,678	954.0	51.6	—	1,005.6
Developed	4,945	3,720	8,665	334.4	33.9	—	368.3
Undeveloped	2,902	2,111	5,013	619.6	17.7	—	637.3
Total	7,847	5,831	13,678	954.0	51.6	—	1,005.6

Notes:

(1) Definitions:

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

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

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

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

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

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

(4) 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.

(5) Includes approximately 398 million barrels attributable to the contribution of interests to FCCL.

(6) Reserves estimates at December 31, 2008 for properties located in Alberta have been prepared using the Alberta royalty framework which came into effect on January 1, 2009.

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 to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for 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		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Future cash inflows	64,308	95,778	72,262	26,620	38,398	27,165
Less future:						
Production costs	23,017	25,089	20,471	6,079	5,869	4,123
Development costs	9,800	10,171	9,355	5,227	6,943	4,715
Asset retirement obligation payments	2,995	3,320	2,397	488	532	396
Income taxes	5,746	12,871	8,816	2,961	7,375	5,349
Future net cash flows	22,750	44,327	31,223	11,865	17,679	12,582
Less 10% annual discount for estimated timing of cash flows	10,036	21,663	14,627	5,218	8,196	6,128
Discounted future net cash flows	12,714	22,664	16,596	6,647	9,483	6,454

	Total		
	2008	2007	2006
	($ millions)		
Future cash inflows	90,928	134,176	99,427
Less future:			
Production costs	29,096	30,958	24,594
Development costs	15,027	17,114	14,070
Asset retirement obligation payments	3,483	3,852	2,793
Income taxes	8,707	20,246	14,165
Future net cash flows	34,615	62,006	43,805
Less 10% annual discount for estimated timing of cash flows	15,254	29,859	20,755
Discounted future net cash flows	19,361	32,147	23,050

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

	Canada			United States		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Balance, beginning of year	22,664	16,596	20,137	9,483	6,454	11,472
Changes resulting from:						
Sales of oil and gas produced during the period	(7,346)	(6,055)	(5,970)	(4,125)	(3,281)	(2,373)
Discoveries and extensions, net of related costs	2,031	3,632	2,429	904	1,591	877
Purchases of proved reserves in place	58	120	—	14	372	69
Sales of proved reserves in place	(321)	(1,283)	(19)	(197)	(15)	(85)
Net change in prices and production costs	(14,632)	9,671	(6,260)	(4,204)	4,818	(7,636)
Revisions to quantity estimates	1,736	603	1,486	667	830	265
Accretion of discount	2,905	2,087	2,809	1,346	924	1,714
Previously estimated development costs incurred net of change in future development costs	1,923	(259)	(910)	315	(907)	(350)
Other	321	(341)	(782)	88	(113)	(381)
Net change in income taxes	3,375	(2,107)	3,676	2,356	(1,190)	2,882
Balance, end of year	12,714	22,664	16,596	6,647	9,483	6,454

	Ecuador			Total		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Balance, beginning of year	—	—	1,568	32,147	23,050	33,177
Changes resulting from:						
Sales of oil and gas produced during the period	—	—	(142)	(11,471)	(9,336)	(8,485)
Discoveries and extensions, net of related costs	—	—	—	2,935	5,223	3,306
Purchases of proved reserves in place	—	—	—	72	492	69
Sales of proved reserves in place	—	—	(1,359)	(518)	(1,298)	(1,463)
Net change in prices and production costs	—	—	—	(18,836)	14,489	(13,896)
Revisions to quantity estimates	—	—	—	2,403	1,433	1,751
Accretion of discount	—	—	—	4,251	3,011	4,523
Previously estimated development costs incurred net of change in future development costs	—	—	(46)	2,238	(1,166)	(1,306)
Other	—	—	—	409	(454)	(1,163)
Net change in income taxes	—	—	(21)	5,731	(3,297)	6,537
Balance, end of year	—	—	—	19,361	32,147	23,050

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador[1]		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	8,848	7,361	7,190	5,127	4,065	3,096	—	—	190
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,502	1,306	1,220	1,002	784	723	—	—	48
Depreciation, depletion and amortization	2,198	2,298	2,146	1,691	1,181	869	—	—	84
Operating income (loss)	5,148	3,757	3,824	2,434	2,100	1,504	—	—	58
Income taxes	1,502	1,114	1,235	937	809	556	—	—	21
Results of operations	3,646	2,643	2,589	1,497	1,291	948	—	—	37

	Other			Total		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Oil and gas revenues, net of royalties, transportation and selling costs	2	—	2	13,977	11,426	10,478
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	(2)	19	11	2,502	2,109	2,002
Depreciation, depletion and amortization	39	69	10	3,928	3,548	3,109
Operating income (loss)	(35)	(88)	(19)	7,547	5,769	5,367
Income taxes	—	—	—	2,439	1,923	1,812
Results of operations	(35)	(88)	(19)	5,108	3,846	3,555

Note:

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of approximately $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 represent 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.

Capitalized Costs

	Canada			United States		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Proved oil and gas properties	33,159	36,780	31,546	15,653	13,738	9,796
Unproved oil and gas properties	870	1,380	1,700	3,399	1,852	1,221
Total Capital cost	34,029	38,160	33,246	19,052	15,590	11,017
Accumulated DD&A	17,434	19,286	14,261	5,511	3,783	2,595
Net capitalized costs	16,595	18,874	18,985	13,541	11,807	8,422

	Other			Total		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Proved oil and gas properties	—	—	—	48,812	50,518	41,342
Unproved oil and gas properties	122	297	361	4,391	3,529	3,282
Total Capital cost	122	297	361	53,203	54,047	44,624
Accumulated DD&A	112	160	98	23,057	23,229	16,954
Net capitalized costs	10	137	263	30,146	30,818	27,670

Costs Incurred

	Canada			United States			Ecuador		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
	($ millions)								
Acquisitions									
— Unproved	32	28	—	1,006	1,048	278	—	—	—
— Proved	119	61	47	17	1,565	6	—	—	—
Total acquisitions	151	89	47	1,023	2,613	284	—	—	—
Exploration costs	474	427	403	197	48	236	—	—	1
Development costs	3,328	3,309	3,611	2,418	1,871	1,826	—	—	46
Total costs incurred	3,953	3,825	4,061	3,638	4,532	2,346	—	—	47

	Other			Total		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Acquisitions						
— Unproved	—	—	—	1,038	1,076	278
— Proved	—	—	—	136	1,626	53
Total acquisitions	—	—	—	1,174	2,702	331
Exploration costs	17	60	75	688	535	715
Development costs	—	—	—	5,746	5,180	5,483
Total costs incurred	17	60	75	7,608	8,417	6,529

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 — 2008				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada	2,205	2,181	2,243	2,212	2,181
USA	1,633	1,677	1,674	1,629	1,552
Total Produced Gas	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids[1] *(bbls/d)*					
Canada	120,230	123,019	119,703	114,121	124,056
USA	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*					
Canada	2,926	2,919	2,961	2,897	2,926
USA	1,713	1,754	1,757	1,710	1,631
Total Continuing Operations *(MMcfe/d)*	4,639	4,673	4,718	4,607	4,557

	Production Volumes — 2008				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	842	820	831	856	860
Canadian Foothills	1,300	1,302	1,351	1,289	1,256
USA	1,633	1,677	1,674	1,629	1,552
Integrated Oil — Other	63	59	61	67	65
Total Produced Gas	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					
Canadian Plains	31,128	32,147	30,134	30,479	31,752
Canadian Foothills	8,473	8,437	8,217	8,376	8,867
Heavy Oil					
Canadian Plains	35,029	32,843	34,655	34,618	38,029
Foster Creek/Christina Lake	30,183	35,068	31,547	24,671	29,376
Integrated Oil — Other	2,729	2,133	2,273	3,009	3,514
Natural Gas Liquids[1]					
Canadian Plains	1,181	1,126	1,147	1,189	1,262
Canadian Foothills	11,507	11,265	11,730	11,779	11,256
USA	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	133,580	135,850	133,556	127,603	137,288
Total Continuing Operations *(MMcfe/d)*	4,639	4,673	4,718	4,607	4,557

Note:

(1) Natural gas liquids include condensate 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
USA	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[1] *(bbls/d)*					
Canada	119,974	121,346	120,805	119,607	118,087
USA	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	134,154	136,137	136,383	133,416	130,590
Total *(MMcfe/d)*					
Canada	2,941	2,986	2,968	2,920	2,887
USA	1,430	1,553	1,480	1,386	1,297
Total Continuing Operations *(MMcfe/d)*	4,371	4,539	4,448	4,306	4,184

	Production Volumes — 2007				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	875	876	858	874	891
Canadian Foothills	1,255	1,313	1,280	1,231	1,196
USA	1,345	1,464	1,387	1,303	1,222
Integrated Oil — Other	91	69	105	98	91
Total Produced Gas	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					
Canadian Plains	32,156	31,706	32,064	31,740	33,129
Canadian Foothills	8,216	8,441	7,978	7,959	8,489
Heavy Oil					
Canadian Plains	38,784	38,581	38,647	38,408	39,510
Foster Creek/Christina Lake	26,814	27,190	28,740	27,994	23,269
Integrated Oil — Other	2,688	3,040	2,235	2,489	2,990
Natural Gas Liquids[1]					
Canadian Plains	1,260	1,422	1,209	1,206	1,203
Canadian Foothills	10,056	10,966	9,932	9,811	9,497
USA	14,180	14,791	15,578	13,809	12,503
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.

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

	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
USA	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(1) *(bbls/d)*					
Canada	144,315	142,085	143,410	138,506	153,391
USA	12,958	12,584	13,311	13,353	12,582
Total Oil and Natural Gas Liquids	157,273	154,669	156,721	151,859	165,973
Total *(MMcfe/d)*					
Canada	3,051	3,057	3,022	3,023	3,103
USA	1,260	1,277	1,277	1,249	1,236
Total Continuing Operations *(MMcfe/d)*	4,311	4,334	4,299	4,272	4,339

	Production Volumes — 2006				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	906	901	899	894	932
Canadian Foothills	1,166	1,207	1,155	1,177	1,128
USA	1,182	1,201	1,197	1,169	1,161
Integrated Oil — Other	113	97	108	121	122
Total Produced Gas	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					
Canadian Plains	34,939	32,995	36,948	33,949	35,543
Canadian Foothills	9,037	8,643	8,717	9,163	9,970
Heavy Oil					
Canadian Plains	40,673	36,572	39,332	39,101	48,356
Foster Creek/Christina Lake	42,768	46,678	43,073	39,215	42,050
Integrated Oil — Other	5,185	5,341	3,953	5,471	5,466
Natural Gas Liquids(1)					
Canadian Plains	1,380	1,397	1,326	1,318	1,479
Canadian Foothills	10,333	10,459	10,061	10,289	10,527
USA	12,958	12,584	13,311	13,353	12,582
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.

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 — 2008				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canadian Plains ($/Mcf)					
Price	7.77	5.65	8.67	9.50	7.19
Production and mineral taxes	0.12	0.06	0.17	0.17	0.06
Transportation and selling	0.23	0.21	0.24	0.22	0.25
Operating	0.78	0.65	0.59	0.96	0.93
Netback	6.64	4.73	7.67	8.15	5.95
Produced Gas — Canadian Foothills ($/Mcf)					
Price	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	0.06	0.03	0.09	0.09	0.03
Transportation and selling	0.42	0.37	0.43	0.43	0.47
Operating	1.15	0.98	0.87	1.39	1.41
Netback	6.49	4.49	7.64	8.03	5.70
Produced Gas — Canada ($/Mcf)					
Price	7.97	5.78	8.88	9.76	7.44
Production and mineral taxes	0.08	0.04	0.12	0.12	0.04
Transportation and selling	0.35	0.31	0.36	0.35	0.38
Operating	1.03	0.87	0.77	1.23	1.25
Netback	6.51	4.56	7.63	8.06	5.77
Produced Gas — USA ($/Mcf)					
Price	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	0.56	0.35	0.56	0.72	0.62
Transportation and selling	0.84	0.87	0.86	0.81	0.81
Operating	0.59	0.56	0.38	0.71	0.71
Netback	5.90	3.23	6.74	7.69	6.05
Produced Gas — Total ($/Mcf)					
Price	7.94	5.44	8.74	9.83	7.75
Production and mineral taxes	0.28	0.17	0.31	0.37	0.28
Transportation and selling	0.56	0.55	0.57	0.55	0.56
Operating	0.84	0.74	0.61	1.01	1.02
Netback	6.26	3.98	7.25	7.90	5.89
Natural Gas Liquids — Canadian Plains ($/bbl)					
Price	78.91	45.13	98.35	96.34	75.09
Production and mineral taxes	—	—	—	—	—
Transportation and selling	—	—	0.01	—	—
Netback	78.91	45.13	98.34	96.34	75.09
Natural Gas Liquids — Canadian Foothills ($/bbl)					
Price	80.22	42.03	95.49	101.23	80.80
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.33	1.33	1.20	1.73	1.04
Netback	78.89	40.70	94.29	99.50	79.76

	Per-Unit Results — 2008				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — Canada ($/bbl)					
Price	80.10	42.31	95.74	100.78	80.23
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.21	1.21	1.10	1.57	0.94
Netback	78.89	41.10	94.64	99.21	79.29
Natural Gas Liquids — USA[1] ($/bbl)					
Price	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	7.25	3.79	8.19	9.75	7.13
Transportation and selling	—	—	—	—	—
Netback	75.93	41.60	89.44	95.98	75.09
Natural Gas Liquids — Total ($/bbl)					
Price	81.67	43.88	96.72	103.29	81.24
Production and mineral taxes	3.70	1.93	4.25	4.94	3.63
Transportation and selling	0.59	0.59	0.53	0.78	0.46
Netback	77.38	41.36	91.94	97.57	77.15
Crude Oil — Light and Medium — Canadian Plains ($/bbl)					
Price	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	3.33	2.05	4.70	3.97	2.72
Transportation and selling	1.20	0.96	1.41	1.27	1.16
Operating	10.56	8.28	9.40	13.05	11.60
Netback	69.75	30.31	92.08	88.79	70.42
Crude Oil — Light and Medium — Canadian Foothills ($/bbl)					
Price	91.78	47.51	112.73	114.28	93.42
Production and mineral taxes	1.48	1.11	1.65	2.05	1.16
Transportation and selling	2.07	1.55	2.12	2.70	1.92
Operating	12.75	11.68	10.02	15.39	13.84
Netback	75.48	33.17	98.94	94.14	76.50
Crude Oil — Heavy — Canadian Plains ($/bbl)					
Price	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	1.60	1.13	2.42	1.60	1.29
Operating	9.04	7.17	7.62	11.30	9.93
Netback	63.41	22.94	85.75	85.85	59.15
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/bbl)					
Price	80.31	37.20	102.66	103.40	78.82
Production and mineral taxes	1.56	1.02	2.16	1.81	1.28
Transportation and selling	1.52	1.13	2.00	1.61	1.36
Operating	10.43	8.28	8.99	13.00	11.39
Netback	66.80	26.77	89.51	86.98	64.79
Crude Oil — Heavy — Foster Creek/Christina Lake ($/bbl)					
Price[2]	62.44	19.86	91.21	93.64	59.67
Production and mineral taxes	—	—	—	—	—
Transportation and selling	2.36	2.04	2.10	2.77	2.72
Operating	15.53	10.73	15.53	21.41	16.62
Netback	44.55	7.09	73.58	69.46	40.33

	Per-Unit Results — 2008				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total[3] ($/bbl)					
Price	75.36	31.58	99.39	100.99	74.10
Production and mineral taxes	1.13	0.69	1.54	1.36	0.96
Transportation and selling	1.75	1.43	2.03	1.90	1.69
Operating	11.84	9.08	10.86	15.08	12.68
Netback	60.64	20.38	84.96	82.65	58.77
Total Liquids — Canada ($/bbl)					
Price	75.85	32.63	98.99	100.97	74.69
Production and mineral taxes	1.01	0.62	1.37	1.20	0.86
Transportation and selling	1.70	1.41	1.93	1.86	1.62
Operating	10.57	8.19	9.68	13.34	11.30
Netback	62.57	22.41	86.01	84.57	60.91
Total Liquids ($/bbl)					
Price	76.58	33.81	98.85	101.46	75.44
Production and mineral taxes	1.63	0.92	2.09	2.09	1.46
Transportation and selling	1.53	1.28	1.72	1.67	1.46
Operating	9.55	7.43	8.66	12.00	10.30
Netback	63.87	24.18	86.38	85.70	62.22
Total ($/Mcfe)					
Price	8.77	5.48	10.04	11.02	8.61
Production and mineral taxes	0.28	0.17	0.32	0.37	0.28
Transportation and selling	0.50	0.49	0.53	0.50	0.50
Operating[4]	0.97	0.83	0.75	1.17	1.15
Netback	7.02	3.99	8.44	8.98	6.68

Notes:

(1) The Natural Gas Liquids — USA netback is equivalent to the Total Liquids — USA netback.

(2) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 — $4.26/bbl; Q4 2008 — $11.21/bbl; Q3 2008 — $3.07/bbl).

(3) The Crude Oil — Total netback is equivalent to the Crude Oil — Canada netback.

(4) Operating costs for the year include a recovery of costs related to long-term incentives of $0.01/Mcfe.

	Per-Unit Results — 2007				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canadian Plains ($/Mcf)					
Price	6.10	6.21	5.26	6.66	6.25
Production and mineral taxes	0.11	0.04	0.13	0.14	0.12
Transportation and selling	0.26	0.25	0.25	0.26	0.27
Operating	0.69	0.81	0.62	0.69	0.65
Netback	5.04	5.11	4.26	5.57	5.21
Produced Gas — Canadian Foothills ($/Mcf)					
Price	6.30	6.44	5.46	6.86	6.46
Production and mineral taxes	0.08	0.04	0.08	0.11	0.10
Transportation and selling	0.42	0.41	0.41	0.43	0.43
Operating	1.05	1.14	0.96	1.02	1.09
Netback	4.75	4.85	4.01	5.30	4.84
Produced Gas — Canada ($/Mcf)					
Price	6.20	6.35	5.36	6.76	6.36
Production and mineral taxes	0.09	0.03	0.10	0.11	0.10
Transportation and selling	0.35	0.35	0.34	0.36	0.36
Operating	0.92	1.03	0.83	0.90	0.91
Netback	4.84	4.94	4.09	5.39	4.99
Produced Gas — USA ($/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 ($/Mcf)					
Price	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	0.18	0.14	0.21	0.14	0.26
Transportation and selling	0.45	0.46	0.44	0.47	0.45
Operating	0.82	0.90	0.72	0.83	0.82
Netback	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids — Canadian Plains ($/bbl)					
Price	59.98	73.12	61.29	56.08	46.69
Production and mineral taxes	—	—	—	—	—
Transportation and selling	—	—	—	—	—
Netback	59.98	73.12	61.29	56.08	46.69
Natural Gas Liquids — Canadian Foothills ($/bbl)					
Price	59.26	73.42	63.06	55.10	42.82
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.14	1.08	2.02	0.83	0.61
Netback	58.12	72.34	61.04	54.27	42.21
Natural Gas Liquids — Canada ($/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

	Per-Unit Results — 2007				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — USA[1] ($/bbl)					
Price	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	4.28	6.12	1.95	4.71	4.56
Transportation and selling	0.01	—	0.01	0.01	0.01
Netback	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids — Total ($/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 — Canadian Plains ($/bbl)					
Price	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	2.37	2.36	2.16	2.37	2.59
Transportation and selling	1.33	1.22	1.39	1.27	1.43
Operating	9.20	10.34	8.84	9.10	8.55
Netback	43.51	54.86	47.29	39.69	32.24
Crude Oil — Light and Medium — Canadian Foothills ($/bbl)					
Price	64.63	81.51	67.07	57.00	52.31
Production and mineral taxes	1.05	1.59	0.76	1.47	0.37
Transportation and selling	1.77	1.66	2.16	1.79	1.49
Operating	10.84	12.72	11.21	9.31	10.03
Netback	50.97	65.54	52.94	44.43	40.42
Crude Oil — Heavy — Canadian Plains ($/bbl)					
Price	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	1.18	1.13	1.36	1.19	1.03
Operating	7.59	9.06	7.27	7.56	6.48
Netback	35.09	39.26	39.53	31.89	29.72
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/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[2]	14.46	14.05	12.55	14.02	17.12
Netback	22.80	28.78	28.21	21.76	13.09

	Per-Unit Results — 2007				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total[3] ($/bbl)					
Price	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	0.79	0.83	0.74	0.84	0.77
Transportation and selling	1.74	1.62	1.64	1.94	1.75
Operating	10.49	11.43	9.72	10.27	10.54
Netback	34.88	42.35	39.40	31.87	26.13
Total Liquids — Canada ($/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[4]	0.93	1.02	0.83	0.93	0.95
Netback	4.82	4.98	4.37	5.14	4.79

Notes:

(1) The Natural Gas Liquids — USA netback is equivalent to the Total Liquids — USA netback.

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

(3) The Crude Oil — Total netback is equivalent to the Crude Oil — Canada netback.

(4) Operating costs for the year include costs of $0.05/Mcfe related to long-term incentives.

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canadian Plains ($/Mcf)					
Price	6.11	5.73	5.49	5.61	7.60
Production and mineral taxes	0.12	0.05	0.11	0.09	0.23
Transportation and selling	0.23	0.23	0.26	0.23	0.21
Operating	0.59	0.61	0.54	0.58	0.62
Netback	5.17	4.84	4.58	4.71	6.54
Produced Gas — Canadian Foothills ($/Mcf)					
Price	6.30	5.99	5.68	5.81	7.81
Production and mineral taxes	0.09	0.05	0.08	0.07	0.16
Transportation and selling	0.44	0.40	0.46	0.45	0.45
Operating	0.92	0.96	0.94	0.89	0.88
Netback	4.85	4.58	4.20	4.40	6.32
Produced Gas — Canada ($/Mcf)					
Price	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	0.10	0.05	0.09	0.08	0.18
Transportation and selling	0.35	0.33	0.37	0.35	0.34
Operating	0.79	0.82	0.78	0.77	0.79
Netback	4.96	4.67	4.35	4.51	6.35
Produced Gas — USA ($/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 ($/Mcf)					
Price	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	0.24	0.21	0.21	0.13	0.41
Transportation and selling	0.42	0.42	0.44	0.40	0.40
Operating	0.74	0.77	0.71	0.74	0.74
Netback	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids — Canadian Plains ($/bbl)					
Price	51.10	46.03	57.46	54.24	47.35
Production and mineral taxes	—	—	—	—	—
Transportation and selling	—	—	—	—	—
Netback	51.10	46.03	57.46	54.24	47.35
Natural Gas Liquids — Canadian Foothills ($/bbl)					
Price	51.12	44.63	55.75	55.31	49.05
Production and mineral taxes	—	—	—	—	—
Transportation and selling	0.75	0.66	0.84	0.82	0.70
Netback	50.37	43.97	54.91	54.49	48.35
Natural Gas Liquids — Canada ($/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

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — USA[1] ($/bbl)					
Price	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	4.19	4.62	4.42	2.60	5.18
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids — Total ($/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 — Canadian Plains ($/bbl)					
Price	50.04	42.27	54.56	60.08	42.96
Production and mineral taxes	2.39	2.45	2.42	2.73	1.98
Transportation and selling	0.88	0.58	1.18	0.59	1.12
Operating	8.18	8.37	9.70	6.74	7.81
Netback	38.59	30.87	41.26	50.02	32.05
Crude Oil — Light and Medium — Canadian Foothills ($/bbl)					
Price	57.74	46.27	63.26	68.08	53.43
Production and mineral taxes	1.27	0.96	0.83	1.54	1.69
Transportation and selling	1.41	0.72	2.05	0.89	1.95
Operating	10.21	11.13	11.85	9.37	8.72
Netback	44.85	33.46	48.53	56.28	41.07
Crude Oil — Heavy — Canadian Plains ($/bbl)					
Price	37.20	26.28	54.68	45.98	24.28
Production and mineral taxes	0.06	0.08	0.06	0.04	0.05
Transportation and selling	0.71	(0.30)	1.36	0.65	1.05
Operating	5.99	7.48	5.50	5.70	5.46
Netback	30.44	19.02	47.76	39.59	17.72
Crude Oil — Total — excluding Foster Creek/Christina Lake ($/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	12.38	13.07	14.06	11.78	10.39
Netback	21.47	23.51	20.49	31.37	10.89

	Per-Unit Results — 2006				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Total[(2)] ($/bbl)					
Price	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	0.77	0.74	0.81	0.88	0.66
Transportation and selling	1.40	1.11	1.74	1.54	1.24
Operating	9.09	10.05	10.20	8.34	7.82
Netback	30.57	25.04	35.99	40.86	21.04
Total Liquids — Canada ($/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[(3)]	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

Note:

(1) The Natural Gas Liquids — USA netback is equivalent to the Total Liquids — USA netback.

(2) The Crude Oil — Total netback is equivalent to the Crude Oil — Canada netback.

(3) Operating costs for the year include costs related to long-term incentives of $0.02/Mcfe.

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

	2008				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.02)	1.74	(0.80)	(1.29)	0.27
Liquids ($/bbl)	(5.46)	2.35	(7.97)	(10.99)	(5.85)
Total ($/Mcfe)	(0.17)	1.50	(0.89)	(1.38)	0.05

	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)

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:											
2008:											
Canada											
Canadian Plains	5	3	1	1	2	1	8	5	34	42	5
Canadian Foothills	70	54	8	5	—	—	78	59	69	147	59
USA	26	14	—	—	—	—	26	14	—	26	14
Other	—	—	—	—	3	1	3	1	—	3	1
Total	101	71	9	6	5	2	115	79	103	218	79
2007:											
Canada											
Canadian Plains	4	4	3	3	—	—	7	7	89	96	7
Canadian Foothills	116	92	4	3	—	—	120	95	91	211	95
USA	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											
Canadian Plains	19	18	2	2	—	—	21	20	108	129	20
Canadian Foothills	262	212	5	5	7	6	274	223	20	294	223
USA	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

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:											
2008:											
Canada											
Canadian Plains	1,489	1,372	105	92	7	7	1,601	1,471	503	2,104	1,471
Canadian Foothills	1,088	989	17	16	—	—	1,105	1,005	329	1,434	1,005
Integrated Oil — Canada	13	13	41	21	4	4	58	38	41	99	38
USA	904	736	—	—	—	—	904	736	378	1,282	736
Total	3,494	3,110	163	129	11	11	3,668	3,250	1,251	4,919	3,250
2007:											
Canada											
Canadian Plains	2,215	2,115	161	138	4	3	2,380	2,256	466	2,846	2,256
Canadian Foothills	1,528	1,425	20	18	1	1	1,549	1,444	325	1,874	1,444
Integrated Oil — Canada	6	2	55	29	6	4	67	35	43	110	35
USA	809	641	—	—	1	1	810	642	36	846	642
Total	4,558	4,183	236	185	12	9	4,806	4,377	870	5,676	4,377
2006:											
Canada											
Canadian Plains	1,546	1,525	118	88	1	1	1,665	1,614	822	2,487	1,614
Canadian Foothills	1,187	1,048	13	7	—	—	1,200	1,055	32	1,232	1,055
Integrated Oil — Canada	66	66	8	8	24	23	98	97	1	99	97
USA	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
Discontinued Operations:											
Ecuador — 2006	—	—	7	6	1	1	8	7	—	8	7

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, 2008, EnCana was in the process of drilling 26 gross wells (19 net wells) in Canada and 47 gross wells (38 net wells) in the U.S.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2008.

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	40,458	38,224	4,032	3,567	44,490	41,791
British Columbia	2,023	1,894	17	12	2,040	1,906
Saskatchewan	452	419	917	600	1,369	1,019
Manitoba	—	—	1	1	1	1
Total Canada	42,933	40,537	4,967	4,180	47,900	44,717
Colorado	4,741	4,159	6	2	4,747	4,161
Texas	1,741	1,213	40	29	1,781	1,242
Wyoming	2,151	1,488	4	3	2,155	1,491
Utah	35	31	12	12	47	43
Louisiana	27	18	—	—	27	18
Kansas	1	1	—	—	1	1
Montana	1	1	—	—	1	1
Total United States	8,697	6,911	62	46	8,759	6,957
Total	51,630	47,448	5,029	4,226	56,659	51,674

Notes:

(1) EnCana has varying royalty interests in 16,437 natural gas wells and 10,364 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 34,582 gross natural gas wells (32,807 net wells) and 1,498 gross crude oil wells (1,345 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2008.

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	— Fee	4,524	4,524	2,258	2,258	6,782	6,782
	— Crown	4,130	3,213	4,148	3,251	8,278	6,464
	— Freehold	275	164	163	141	438	305
		8,929	7,901	6,569	5,650	15,498	13,551
British Columbia	— Crown	1,005	901	3,095	2,533	4,100	3,434
	— Freehold	—	—	7	—	7	—
		1,005	901	3,102	2,533	4,107	3,434
Saskatchewan	— Fee	64	64	447	447	511	511
	— Crown	133	111	410	352	543	463
	— Freehold	14	10	48	46	62	56
		211	185	905	845	1,116	1,030
Manitoba	— Fee	3	3	261	261	264	264
Newfoundland and Labrador	— Crown	—	—	35	2	35	2
Nova Scotia	— Crown	—	—	41	29	41	29
Northwest Territories	— Crown	—	—	45	12	45	12
Total Canada		10,148	8,990	10,958	9,332	21,106	18,322

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	— Federal/State Lands	199	184	668	614	867	798
	— Freehold	102	93	166	153	268	246
	— Fee	1	1	4	4	5	5
		302	278	838	771	1,140	1,049
Texas	— Federal/State Lands	12	7	460	441	472	448
	— Freehold	227	166	1,091	873	1,318	1,039
	— Fee	—	—	4	2	4	2
		239	173	1,555	1,316	1,794	1,489
Wyoming	— Federal/State Lands	137	82	546	393	683	475
	— Freehold	17	10	31	16	48	26
		154	92	577	409	731	501
Other	— Federal/State Lands	8	7	360	220	368	227
	— Freehold	12	10	1,257	1,062	1,269	1,072
	— Fee	—	—	87	87	87	87
		20	17	1,704	1,369	1,724	1,386
Total United States		715	560	4,674	3,865	5,389	4,425
Greenland		—	—	1,700	808	1,700	808
Azerbaijan		—	—	346	17	346	17
Australia		—	—	104	40	104	40
Qatar(7)		—	—	—	—	—	—
Brazil(8)		—	—	—	—	—	—
France(9)		—	—	—	—	—	—
Total International		—	—	2,150	865	2,150	865
Total		10,863	9,550	17,782	14,062	28,645	23,612

Notes:

(1) This table excludes approximately 4.9 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 October 2008, EnCana relinquished its interests in Qatar.

(8) In September 2008, EnCana sold its remaining interests in Brazil.

(9) In December 2008, EnCana completed the sale of all of its interests in France.

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 2008 and 2007.

	2008	2007
	($ millions)	
Capital Investment		
Canada		
Canadian Plains	847	846
Canadian Foothills	2,299	2,439
Integrated Oil - Canada	656	451
USA	2,615	1,919
Downstream Refining	478	220
Market Optimization	17	6
Corporate & Other	168	154
Capital Investment	7,080	6,035
Acquisitions		
Property		
Canada		
Canadian Foothills	151	75
Integrated Oil - Canada	—	14
USA(1)	1,023	2,613
Divestitures		
Property		
Canada		
Canadian Plains	(39)	—
Canadian Foothills(2)	(400)	(213)
Integrated Oil - Canada	(8)	—
USA	(251)	(10)
Corporate & Other(3)	(41)	(47)
Corporate		
Corporate & Other(4)	(165)	(211)
Net Acquisition and Divestiture Activity	270	2,221
Net Capital Investment	7,350	8,256

Notes:

(1) In 2008, mainly includes Haynesville properties. In 2007, mainly includes the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in East Texas acquired November 20, 2007.

(2) In 2007, consists primarily of the sale of Mackenzie Delta assets which was completed on May 30, 2007.

(3) In 2007, consists primarily of the sale of EnCana's office building project assets, The Bow, which was completed on February 9, 2007, and the sale of Australia assets which was completed on August 15, 2007.

(4) In 2008, mainly includes the sale of interests in Brazil which was completed on September 18, 2008. In 2007, sale of interests in Chad was completed on January 12, 2007 and sale of interests in Oman was completed on November 28, 2007.

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 22 to EnCana's audited consolidated financial statements for the year ended December 31, 2008.

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 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 incorporates the potential costs of carbon into future planning. The Corporate Responsibility, Environment, Health and Safety Committee of EnCana's Board of Directors reviews the impact of a variety of carbon constrained scenarios on EnCana's strategy with a current price range from $15 to $65 per tonne of emissions, applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2008, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2009. 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 $6.6 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) EH&S; (vii) stakeholder engagement; and (viii) socio-economic and community development.

The Policy and any revisions are approved by EnCana's Executive Team and its Board of Directors. 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 EH&S; (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 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.

Through the Policy, EnCana is committed to protecting the health and safety of all individuals affected by its activities, including its workforce and the public. EnCana will not compromise the health and safety of any individual in the conduct of its activities. EnCana will strive to provide a safe and healthy working environment, and will expect its workers to comply with the health and safety practices established for their protection and that of the public.

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 and a requirement for acknowledgement and sign-off on key policies from the Board of Directors and employees; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and to manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide and specific Aboriginal Community Engagement Guide; (v) corporate responsibility performance metrics to track the Corporation's progress; (vi) an energy efficiency program that focuses on reducing energy use at EnCana's operations and supports initiatives at the community level while also incenting employees to reduce energy use in their homes; (vii) contribution of a minimum of 1 percent of EnCana's pre-tax domestic profits to charitable and non-profit organizations in the communities in which EnCana operates; (viii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of EnCana policies or practices and other regulations; (ix) 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; (x) an internal corporate EH&S audit program that evaluates EnCana's compliance with the expectations and requirements of the EH&S management system; and (xi) related policies and practices such as an Alcohol and Drug Policy, a Business Conduct & Ethics Practice and guidelines for correct behaviours with respect to the acceptance of gifts, conflicts of interest and the appropriate use of EnCana equipment and technology in a manner that is consistent with leading ethical business practices. 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, 2008, EnCana employed 6,048 full time equivalent employees as set forth in the following table.

	FTE Employees
Canadian Plains Division	1,101
Canadian Foothills Division	1,765
USA Division	1,665
Integrated Oil Division	884
Corporate	633
Total	6,048

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

Foreign Operations

As at December 31, 2008, 100 percent 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[1]	Principal Occupation
RALPH S. CUNNINGHAM[3,4,7,8] . . . . Houston, Texas, United States	2003	President & Chief Executive Officer EPE Holdings, LLC *(Midstream energy services)*
PATRICK D. DANIEL[2,5,7,8] . . . . Calgary, Alberta, Canada	2001	President & Chief Executive Officer Enbridge Inc. *(Energy delivery)*
IAN W. DELANEY[4,5,7,8] . . . . Toronto, Ontario, Canada	1999	Chairman & Chief Executive Officer Sherritt International Corporation *(Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)*
RANDALL K. ERESMAN[7,10] . . . . Calgary, Alberta, Canada	2006	President & Chief Executive Officer EnCana Corporation
CLAIRE S. FARLEY[3,6,7,9] . . . . Houston, Texas, United States	2008	Advisory Director Jefferies Randall & Dewey *(Global oil and gas energy industry advisor)*
MICHAEL A. GRANDIN[4,5,6,7,8,12] . . . . Calgary, Alberta, Canada	1998	Corporate Director
BARRY W. HARRISON[2,5,7,9,13] . . . . Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
DALE A. LUCAS[2,4,7,9] . . . . Calgary, Alberta, Canada	1997	Corporate Director
VALERIE A. A. NIELSEN[3,6,7,8] . . . . Calgary, Alberta, Canada	1990	Corporate Director

Name and Municipality of Residence	Director Since[(1)]	Principal Occupation
DAVID P. O'BRIEN, O.C.[(5,7,9,11,14)] . . . . Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT[(2,4,7,9)] . . . . West Vancouver, British Columbia, Canada	2003	Corporate Director
ALLAN P. SAWIN[(2,4,7,9)] . . . . Edmonton, Alberta, Canada	2007	President Bear Investments Inc. *(Private investment company)*
JAMES M. STANFORD, O.C.[(2,6,7,8)] . . . . Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Private investment management)*
WAYNE G. THOMSON[(3,6,7,8)] . . . . Calgary, Alberta, Canada	2007	President Virgin Resources Limited *(Private international oil & gas exploration company)*
CLAYTON H. WOITAS[(3,6,7,9)] . . . . Calgary, Alberta, Canada	2008	Chairman & Chief Executive Officer Range Royalty Management Ltd. *(Private oil & gas company)*

Notes:

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

(2) Member of Audit Committee.

(3) Member of Corporate Responsibility, Environment, Health and Safety Committee.

(4) Member of Human Resources and Compensation Committee.

(5) Member of Nominating and Corporate Governance Committee.

(6) Member of Reserves Committee.

(7) On June 4, 2008, the Board of Directors created the GasCo Committee and the Cenovus Committee charged with the oversight of strategic planning, governance and other matters related to each of the two separate public entities that would result from the proposed reorganization announced on May 11, 2008.

(8) Member of Cenovus Committee.

(9) Member of GasCo Committee.

(10) As an officer of EnCana and a non-independent director, Mr. Eresman is not a member of any Board committees, except for the GasCo and Cenovus Committees.

(11) 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.

(12) 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 (U.S.). A liquidation plan for that company received court confirmation later that year.

(13) 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.

(14) 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.

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

At the date of this annual information form, there are 15 directors of the Corporation. All of the current directors were appointed at the last annual meeting of shareholders held on April 22, 2008. At the next annual meeting, shareholders will be asked to elect as directors the 13 individuals listed in the above table, with the exception of Messrs. Lucas and Stanford who are 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)
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, Canadian Gas Marketing and Power
GERARD J. PROTTI Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations
IVOR M. RUSTE 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, U.S.A.	Executive Vice-President *(President, USA Division)*

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:

Since August 1, 2007, Mr. Cunningham has been 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. Delaney, Chairman of the Board of Sherritt International Corporation, assumed the additional responsibilities of Chief Executive Officer effective January 27, 2009.

Ms. Farley became an Advisory Director of Jefferies Randall & Dewey (global oil and gas energy industry advisor) in August 2008. She was Co-President of Jefferies Randall & Dewey from February 2005 to August 2008 and Chief Executive Officer of Randall & Dewey (oil and gas asset transaction advisors) from September 2002 until February 2005 when Randall & Dewey became the Oil and Gas Investment Banking Group of Jefferies & Company, Inc. She was also a Managing Partner of Castex Energy Partners (private exploration and production limited partnership with assets in south Louisiana) from August 2008 to January 2009.

Mr. Grandin was Chairman and Chief Executive Officer of Fording Canadian Coal Trust from February 2003 to October 2008 when the company was acquired by Teck Cominco Limited. He also served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006.

Ms. Peverett was President and Chief Executive Officer of BC Transmission Corporation (BCTC) from April 2005 to January 2009 and was Vice-President, Corporate Services and Chief Financial Officer of BCTC from June 2003 to April 2005. 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.

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.

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 11, 2009, directly or indirectly, or exercised control or direction over an aggregate of 970,092 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 6,061,293 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 National 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) which was acquired by Total E&P Canada Ltd. in August 2008.

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. (private oil and gas company). 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 President of D.A. Lucas Enterprises Inc., a private company owned by Mr. Lucas and through which he consulted internationally. He was Chairman and a director of Petaquilla Copper Ltd. (a public mining company) from April 2007 until September 2008 when the company was acquired by Inmet Mining Corp. During his 45-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 President and Chief Executive Officer of BC Transmission Corporation (BCTC) from April 2005 to January 2009 and was Vice President, Corporate Services and Chief Financial Officer of BCTC (electrical transmission) from June 2003 to April 2005. 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 2008 and 2007.

($ thousands)	2008	2007
Audit Fees(1)	4,060	4,038
Audit-Related Fees(2)	1,053	153
Tax Fees(3)	1,408	847
All Other Fees(4)	5	35
Total	6,526	5,073

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 2008 and 2007, 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 2008 and 2007, 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 2008 and 2007, 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 2007 or 2008.

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, 2008, there were approximately 751 million Common Shares outstanding and no Preferred Shares outstanding.

Common Shares

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

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Corporation. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under predecessor and/or related company replacement plans expire up to ten 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 take-over 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 acquirer, 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 and outlooks of the Corporation's debt as of December 31, 2008.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")
Senior Unsecured Long-Term Rating	A–/CreditWatch Negative	Baa2/Stable	A (low)/Under Review with Developing Implications
Commercial Paper Short-Term Rating	A-1 (low)/CreditWatch Negative	P-2/Stable	R-1 (low)/Stable

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 nor do the ratings comment on 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.

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, which represents the range from highest to lowest quality. A rating of A-1 (low) is the third highest of eight categories and indicates that the obligor has satisfactory capacity to meet its financial commitments. CreditWatch highlights the potential direction of a long-term rating and the "negative" designation indicates that a rating may be lowered.

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. Moody's short-term credit ratings are on a scale that ranges from P-1 (highest quality) to NP (lowest quality). A rating of 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 substantial, but the degree of strength is less than that of higher rated entities. 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 credit ratings are on a scale ranging from R-1 (high) to D, which represents the range from highest to lowest quality. A rating of 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. A rating is placed "Under Review with Developing Implications" when there is uncertainty regarding the outcome of an event. A rating that is "Under Review" remains outstanding; however, this status indicates that the outstanding rating may no longer be appropriate. Upon a rating being placed "Under

Review", the rating trend of stable, positive or negative is removed and when the "Under Review" status is removed, a rating trend is re-established.

Following the announcement of the proposed Arrangement, S&P placed the Corporation's corporate credit and long-term debt ratings on "CreditWatch Negative", Moody's changed its outlook from "Positive" to "Stable" and DBRS placed the Corporation "Under Review with Developing Implications" and confirmed the short-term rating and stable outlook on the short-term rating.

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 2008.

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	(C$ per share)			(millions)	($ per share)			(millions)
2008								
January	70.90	59.95	66.19	49.8	71.72	58.13	66.06	64.7
February	77.29	64.39	75.03	48.4	79.38	63.69	76.21	63.0
March	79.26	70.60	78.20	61.7	79.75	68.83	75.75	67.1
April	88.06	76.41	81.25	49.8	87.69	74.16	80.81	59.8
May	97.81	78.09	89.51	60.0	99.36	76.50	90.37	74.6
June	97.64	87.34	93.36	55.6	96.60	86.22	90.93	71.3
July	95.91	72.00	73.90	74.8	94.41	70.04	72.19	95.8
August	79.97	69.02	79.81	58.4	76.42	64.68	74.90	91.1
September	77.15	63.84	67.96	90.1	74.44	61.13	65.73	134.9
October	68.04	41.36	61.23	112.2	64.19	34.53	50.91	174.0
November	62.99	43.86	60.00	70.2	54.76	34.00	46.81	101.8
December	59.87	47.52	56.96	62.7	48.71	36.58	46.48	80.4

In November 2008 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 November 13, 2008. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange.

In 2008, EnCana purchased approximately 4.8 million shares under the program for an average price of $67.13 for approximately $326 million.

On May 11, 2008 EnCana announced its plans with respect to the proposed Arrangement, and in connection with that proposed transaction, EnCana suspended the purchase of Common Shares for cancellation pending completion of the transaction. Upon completion of the Arrangement, and subject to market conditions prevailing at that time, EnCana intends to resume purchases of Common Shares.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In the second quarter of 2006, EnCana increased its dividend by 33 percent to $0.10 per share quarterly ($0.40 per share annually). In the first quarter of 2007, EnCana increased its dividend by 100 percent to $0.20 per share quarterly ($0.80 per share annually). In the first quarter of 2008, EnCana increased its dividend by 100 percent to $0.40 per share quarterly ($1.60 per share annually). EnCana's Board of Directors has declared a quarterly dividend of $0.40 per share payable on March 31, 2009 to common shareholders of record on March 16, 2009.

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 and in some cases its reputation 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 and refined products 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, refined products, 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 refined product and imported 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.

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

The Corporation's ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond the Corporation's control. In addition to commodity prices and continued market demand for its products, these non-controllable factors include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

Current market conditions are challenging with the global recession negatively impacting commodity prices as well as access to credit and capital markets. These conditions impact EnCana's customers and suppliers and may alter the Corporation's spending and operating plans. There may be unexpected business impacts from this market uncertainty.

EnCana's downstream operations are sensitive to margins for refined products. Margin volatility is impacted by numerous conditions including: market competitiveness, the costs of crude oil, labour, electricity, chemicals and other inputs, maintenance and turnaround costs, fluctuations in the supply and demand for refined products, especially production levels at other refineries in the regions which impact the supply of product and therefore crack spreads and prices in those regions, unplanned production disruptions due to equipment failure, power disruptions and other factors including 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 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.

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 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.

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 certainty that EnCana will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

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

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond the Corporation's control. The reserves data in this annual information form represents estimates only. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, 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 fail to fulfill their obligations under the hedging agreements.

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, acts of vandalism and terrorism, 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 and maintain the operation of the refineries.

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 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 for $20 million and of a previously disclosed consolidated class action lawsuit in the U.S. District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for $23.0 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Corporation and WD intend to vigorously defend this outstanding claim; 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.

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.

TRANSFER AGENTS AND REGISTRARS

In Canada:
CIBC Mellon Trust Company
P.O Box 7010
Adelaide Street Postal Station
Toronto, ON M5C 2W9
Tel: 1-800-387-0825
Website: www.cibcmellon.com/investorinquiry

In the United States:
BNY Mellon Shareowner Services
480 Washington Blvd
Jersey City, NJ
07310
Tel: 1-800-387-0825
Website: www.cibcmellon.com/investorinquiry

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 19, 2009 in respect of the Corporation's consolidated financial statements as at December 31, 2008 and December 31, 2007 and for each of the years in the three year period ended December 31, 2008 and the Corporation's internal control over financial reporting as at December 31, 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Information relating to reserves in this annual information form dated February 20, 2009 was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, each of which is an independent qualified reserves evaluator.

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 1 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, 2008.

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, 2008. The reserves data consists of the following:

   (a) estimated proved oil and gas reserves quantities as at December 31, 2008 using constant prices and costs; and

   (b) 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, 2008:

		Estimated Proved Reserves Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax, 10% discount rate
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	
		(Bcf)	(MMbbl)	(US$MM)
McDaniel & Associates Consultants Ltd. January 16, 2009	Canada	3,936	847	9,164
GLJ Petroleum Consultants Ltd. January 23, 2009	Canada	3,911	107	6,863
Netherland, Sewell & Associates, Inc. January 19, 2009	United States	4,081	49	5,697
DeGolyer and MacNaughton January 20, 2009	United States	1,750	3	2,499
Totals		13,678	1,006	24,223

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 10, 2009

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 a Decision dated September 29, 2008, and require disclosure of information contemplated by, and consistent with, US Disclosure Requirements (as defined in the Decision). Required information includes reserves data, which consist of the following:

(a) proved oil and gas reserves quantities estimated as at December 31, 2008 using constant prices and costs; and

(b) 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 10, 2009 (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 their probability of 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
Director and Chairman of the Reserves Committee

February 11, 2009

APPENDIX C

Audit Committee Mandate

Last updated February 10, 2009

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 National Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 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 (the "*Exchange Act*"), and the rules adopted by the U.S. Securities and Exchange Commission ("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 SEC.

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 *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 therefore, 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.