EnCana Corporation

Annual Information Form
February 18, 2010

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Introduction

This is the annual information form of **EnCana Corporation** ("EnCana" or the "Corporation") for the year ended December 31, 2009. 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.

On November 30, 2009, EnCana completed a corporate reorganization (the "Split Transaction") involving the division of EnCana into two independent publicly traded energy companies – EnCana Corporation and Cenovus Energy Inc. ("Cenovus"). The Split Transaction is more fully described under "General Development of the Business". Except where indicated otherwise, the financial, production and other operating data for EnCana in this annual information form for periods prior to the Split Transaction have not been adjusted to remove the results associated with the upstream assets which were transferred to Cenovus under the Split Transaction.

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.

In this annual information form, the term "liquids" is used to represent crude oil and natural gas liquids ("NGLs"). Liquids also include condensate volumes. Certain liquids 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.

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.

Readers are directed to the sections titled "Note Regarding Forward-Looking Statements" and "Note Regarding Reserves Data and Other Oil and Gas Information".

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.

In conjunction with the Split Transaction (described under "General Development of the Business"), EnCana's articles were amended to make certain changes to its share capital. Further information on the Corporation's share capital is disclosed under "Description of Share Capital".

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, 2009. Each of these subsidiaries and partnerships had total assets that exceeded 10 percent of the total consolidated assets of EnCana or annual revenues that exceeded 10 percent of the total consolidated annual revenues of EnCana as at December 31, 2009.

Subsidiaries & Partnerships	**Percentage Directly or Indirectly Owned**	**Jurisdiction of Incorporation, Continuance or Formation**
EnCana USA Holdings	100	Delaware
3080763 Nova Scotia Company	100	Nova Scotia
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Marketing (USA) Inc.	100	Delaware
EnCana USA Investment Holdings	100	Delaware

The above table does not include all of the subsidiaries and partnerships of EnCana. The assets and annual revenues of unnamed subsidiaries and partnerships in the aggregate did not exceed 20 percent of the total consolidated assets or total consolidated annual revenues as at December 31, 2009.

As a general matter, EnCana reorganizes its subsidiaries as required to maintain proper alignment of its business, operating and management structures.

General Development of the Business

EnCana was formed in 2002 through the business combination of Alberta Energy Company Ltd. ("AEC") and PanCanadian Energy Corporation ("PanCanadian"). EnCana is currently one of North America's leading natural gas producers and its strategy is to be a natural gas pure-play company focused on the development of unconventional resources across North America. EnCana's other operations include the transportation and marketing of natural gas and liquids production. 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 are located in North America.

Split Transaction

On November 30, 2009, EnCana completed a corporate reorganization to split into two independent publicly traded energy companies – EnCana Corporation, a natural gas company, and Cenovus Energy Inc., an integrated oil company.

The Split Transaction was initially proposed in May 2008 and was designed to enhance long-term value for shareholders by creating two independent and sustainable companies, each with the ability to pursue and achieve greater success by employing operational strategies best suited to its unique assets and business plan. In October 2008, due to an unusually high level of uncertainty and volatility in the global debt and equity markets, EnCana delayed seeking shareholder and court approval for the Split Transaction until there were clear signs that the global financial markets had stabilized. In September 2009, EnCana announced plans to proceed with the split.

The Split Transaction was effected by way of an arrangement under the CBCA, under which the holders of Common Shares of EnCana received one new EnCana Common Share and one Common Share of Cenovus for each EnCana Common Share previously held. Holders of stock options of EnCana became the holders of stock options of EnCana and Cenovus, with the exercise prices under the stock options being adjusted based on the relative share trading prices of the EnCana and Cenovus Common Shares.

In connection with the Split Transaction, EnCana entered into an Arrangement Agreement with Cenovus and another subsidiary of EnCana dated October 20, 2009 and a Separation and Transition Agreement with Cenovus dated November 20, 2009. The Arrangement Agreement set out the terms and conditions to the arrangement, including the plan of arrangement. The Separation and Transition Agreement set out the mechanics for the separation of the businesses including the dividing of assets, assumption of liabilities and matters governing certain ongoing relationships between EnCana and Cenovus, including reciprocal indemnities with respect to the assets and liabilities kept by EnCana or transferred to Cenovus.

Operating Divisions

EnCana employs a decentralized decision making structure organized by operating divisions. Prior to the completion of the Split Transaction, EnCana's divisions included the Canadian Foothills Division, the Canadian Plains Division, the Integrated Oil Division and the USA Division. Under the Split Transaction, the assets associated with the Canadian Plains Division and the Integrated Oil Division were transferred to Cenovus.

EnCana's operations are currently divided into two operating divisions:

- Canadian Division, formerly the Canadian Foothills Division, which includes natural gas development and production assets located in British Columbia and Alberta, and 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, including the Horn River shale play; (ii) Cutbank Ridge on the Alberta and British Columbia border, including the Montney formation; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in southern 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 in Texas; and (iv) Fort Worth in Texas. The USA Division is also focused on the development of the Haynesville shale play located in Louisiana and Texas and the recent entrance into the Marcellus shale play located in Pennsylvania.

EnCana's proprietary production is substantially sold by the Midstream, Marketing & Fundamentals team, which is focused on enhancing the Corporation's netback price. Midstream, Marketing & Fundamentals manages EnCana's Market Optimization activities, which include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

In 2009, the Corporation formed the Natural Gas Economy team to focus on pursuing the development of expanded natural gas markets in North America, particularly within the areas of power generation and transportation. Due to the technical breakthroughs with unconventional natural gas extraction, the commercial resource in North America has grown to a historical high. This abundance improves the longer term affordability and reliability of natural gas for these potential markets. In addition, increased use of natural gas has the potential to yield lower green house gas and volatile organic compound emissions as compared to other fossil fuel use.

For 2009 financial reporting purposes, EnCana's reportable segments were: (i) Canada; (ii) USA; (iii) Market Optimization; and (iv) Corporate and Other. The Canada reportable segment includes the results from the Canadian Division and Canada – Other. Canada – Other includes the results from the former Canadian Plains Division and the former Integrated Oil Division – Canada operations which were transferred to Cenovus as part of the Split Transaction.

The financial, production and other operating data for EnCana for periods prior to the November 30, 2009 Split Transaction have not been adjusted to remove the results associated with Canada – Other assets which were transferred to Cenovus. The Canada – Other results are reported as continuing operations in accordance with the full cost accounting rules. The U.S. Downstream Refining results prior to the November 30, 2009 Split Transaction are reported as discontinued operations for financial reporting purposes.

Other Developments

The following describes other 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.

2009

- EnCana completed the divestiture of mature conventional oil and natural gas assets for proceeds of approximately $1,000 million in the Canadian Division, $73 million in the USA Division and $17 million in Canada – Other operations.

2008

- EnCana acquired, in several transactions, certain land and mineral interests in the Haynesville shale in Texas and Louisiana for approximately $1,010 million, net to EnCana. These acquisitions increased EnCana's land position in the Haynesville shale to approximately 435,000 net acres, including approximately 63,000 net mineral acres.

- EnCana completed the divestiture of mature, non-core conventional oil and natural gas assets for proceeds of approximately $400 million in the Canadian Division, $251 million in the USA Division and $47 million in Canada – Other operations.

- EnCana completed the sale of all of its interests in France and Brazil and withdrew from Qatar.

- In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. The Wood River refinery was part of the Downstream Refining assets transferred to Cenovus as part of the Split Transaction.

2007

- EnCana, with ConocoPhillips, completed a transaction to create an integrated oil business. The integrated oil business was comprised of two 50-50 operating entities, a Canadian upstream enterprise operated by EnCana and a U.S. downstream enterprise operated by ConocoPhillips. The integrated oil business was subsequently transferred to Cenovus as part of the Split Transaction.

- A subsidiary of EnCana completed the sale of all of its interests in Chad.

- EnCana completed the sale of The Bow office project assets for approximately $57 million. As part of the transaction, EnCana, as tenant, signed a 25-year lease agreement. EnCana has subleased approximately 50 percent of The Bow office space to Cenovus as part of the Split Transaction.

- EnCana's Board of Directors authorized funding for the development of the Deep Panuke natural gas project located offshore Nova Scotia.

- 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.

Narrative Description of the Business

The following map outlines the location of EnCana's North American landholdings and key resource plays as at December 31, 2009.

EnCana’s operations are focused on exploiting North American long-life unconventional natural gas formations, including tight gas, shales and CBM. EnCana attempts to identify early-stage, geographically expansive gas-charged basins and then assembles a large land position to try to capture core resource opportunities. EnCana then focuses on determining cost efficient means for extracting natural gas through a combination of detailed reservoir studies and pilot testing available and emerging drilling and completions technologies. EnCana's manufacturing-style development approach extends over many years. Capital and operating efficiencies are pursued on an ongoing basis and shared across EnCana's expansive portfolio.

EnCana’s operations are primarily located in Canada and the U.S. All of EnCana’s current proved reserves and production are located in North America.

Canadian Division

The Canadian Division, formerly the Canadian Foothills Division, includes EnCana’s natural gas assets in British Columbia and Alberta, and the Deep Panuke natural gas project located offshore Nova Scotia. Four key resource plays are located in the Division: (i) Greater Sierra; (ii) Cutbank Ridge; (iii) Bighorn; and (iv) CBM. The CBM key resource play (Horseshoe Canyon coalbed methane and commingled shallow gas) is located within the Clearwater area. In addition, EnCana has established a leading land position in the Horn River Devonian shale, currently included as part of the Greater Sierra key resource play, and the Montney formation which is included in the Cutbank Ridge key resource play. The Canadian Division also manages the offshore Deep Panuke natural gas project in Atlantic Canada.

In 2009, the Canadian Division had total capital investment in Canada of approximately $1,869 million and drilled approximately 699 net wells. As at December 31, 2009, the Canadian Division had an established land position in Canada of approximately 11.0 million gross acres (9.3 million net acres); of these, approximately 6.0 million gross acres (5.0 million net acres) are undeveloped. The mineral rights on approximately 44 percent of the total net acreage are owned in fee title by EnCana, which means that the mineral rights are held by EnCana in perpetuity and 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. The Canadian Division’s 2009 production averaged approximately 1,319 million cubic feet equivalent per day. The 2009 average production volumes were lowered by approximately 120 million cubic feet equivalent per day, due to shut-in and curtailed production and delayed well completions and tie-ins as a result of the low natural gas price environment.

The following tables summarize the Canadian Division landholdings, daily production and producing wells as at and for the periods indicated.

Landholdings

(thousands of acres at December 31, 2009)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	617	590	1,420	1,168	2,037	1,758	86%
Cutbank Ridge	369	282	884	780	1,253	1,062	85%
Bighorn	256	167	394	292	650	459	71%
Clearwater	3,367	2,959	2,302	2,163	5,669	5,122	90%
Atlantic Canada	-	-	76	32	76	32	42%
Other	416	247	938	574	1,354	821	61%
Canadian Division	5,025	4,245	6,014	5,009	11,039	9,254	84%

Production

(annual average)	Natural Gas (MMcf/d)		Liquids (bbls/d)		Total (MMcfe/d)	
	2009	2008	2009	2008	2009	2008
Greater Sierra	199	220	871	1,044	204	226
Cutbank Ridge	310	296	591	617	313	300
Bighorn	159	167	2,719	3,734	175	189
Clearwater (1)	453	495	9,192	10,777	508	560
Other	103	122	2,507	3,808	119	145
Canadian Division	1,224	1,300	15,880	19,980	1,319	1,420

Note:

(1) The CBM key resource play located within the Clearwater area, averaged production of approximately 316 million cubic feet per day in 2009 (304 million cubic feet per day in 2008).

Producing Wells

(number of wells at December 31, 2009) (1)	Natural Gas		Crude Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	1,037	998	3	3	1,040	1,001
Cutbank Ridge	760	654	8	1	768	655
Bighorn	359	272	10	5	369	277
Clearwater (2)	8,771	8,157	149	98	8,920	8,255
Other	475	380	104	54	579	434
Canadian Division	11,402	10,461	274	161	11,676	10,622

Notes:

(1) Figures exclude wells capable of producing, but not producing, as of December 31, 2009.

(2) At December 31, 2009, the CBM key resource play had approximately 6,243 gross producing gas wells (5,866 net gas wells).

Key Resource Plays and Activities in the Canadian Division

Greater Sierra

The Greater Sierra area is a key resource play located in northeast British Columbia. The primary focus is on the continued development of the Devonian Jean Marie formation and the Horn River Devonian shale formation. In 2009, EnCana drilled approximately 57 net wells in the area and production averaged approximately 199 million cubic feet per day of natural gas. Production has remained relatively constant over the last five years while EnCana has reduced capital expenditures.

At December 31, 2009, EnCana held an average 94 percent working interest in 14 production facilities in the area that were capable of processing approximately 525 million cubic feet per day of natural gas. EnCana also held a 100 percent working 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.

At December 31, 2009, EnCana controlled approximately 440,000 undeveloped gross acres (256,000 net acres) in the Devonian shale formation of the Horn River Basin in northeast British Columbia. The Horn River formation shales (Muskwa, Otter Park and Evie) within EnCana's focus area are upwards of 500 feet thick. At December 31, 2009, these shales have been evaluated with 60 wells (five vertical and 55 horizontal), 13 of which have been placed on long-term production (one vertical and 12 horizontal). In 2009, EnCana and its partner commenced drilling a larger program of horizontal wells in the Two Island Lake area, and constructed a compressor station and 24-inch raw gas transmission pipeline.

EnCana is the operator of the Cabin Gas Plant project to process Horn River shale gas. EnCana continues to make progress on the project and at December 31, 2009, regulatory timelines remained on schedule. The British Columbia Environmental Assessment Office submitted its favourable project recommendation to the Government Cabinet of British Columbia in December 2009. The application is for approximately 800 million cubic feet per day processing capacity, of which EnCana has a 30 percent ownership in the first phase of approximately 400 million cubic feet per day. In January 2010, EnCana received an Environmental Assessment Certificate from the British Columbia Ministry of Environment for the Cabin Gas Plant project. EnCana expects the first phase of processing capacity will be on stream by September 2012. Additional approvals from the British Columbia Oil and Gas Commission are still required and are expected to be forthcoming near the end of the first quarter of 2010.

Cutbank Ridge

The Cutbank Ridge area is a key 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 formations. The Montney and Cadomin formations are almost exclusively being developed with horizontal well technology. Significant improvements have been achieved with respect to horizontal well completions with the application of multi-stage hydraulic fracturing. In 2009, EnCana drilled approximately 71 net wells in the area and production averaged approximately 310 million cubic feet per day of natural gas.

EnCana holds approximately 720,000 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 80 percent reduction in costs on a completed interval basis over the past three years.

EnCana has sour gas processing capacity of approximately 380 million cubic feet per day at its 100 percent owned gas plants at Hythe and Steeprock.

Bighorn

The Bighorn area is a key resource play in west central Alberta, with a focus on exploiting multi-zone stacked Cretaceous sands in the Deep Basin. The primary properties in Bighorn are Resthaven, Kakwa, Redrock and Berland. In 2009, EnCana drilled approximately 69 net wells in the area and production averaged approximately 159 million cubic feet per day of sweet natural gas.

EnCana has a working interest in a number of natural gas plants within the Bighorn area. The Resthaven plant, in which EnCana has approximately 70 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 50 percent of this plant and has firm processing capacity for the remaining 50 percent. EnCana holds a 24 percent working interest in the Berland River plant, which has a capacity of approximately 165 million cubic feet per day.

Clearwater

The Clearwater area extends from the U.S. border to central Alberta. The primary focus of the Clearwater area is the CBM key natural gas resource play which involves Horseshoe Canyon Coals integrated with shallower sands. Within Clearwater, EnCana holds approximately 5.1 million net acres with approximately 2.1 million net acres on the Horseshoe Canyon trend. Approximately 80 percent of the total net acreage landholdings are owned in fee title. In 2009, EnCana drilled approximately 490 net CBM wells and production averaged approximately 316 million cubic feet per day of natural gas from the CBM key resource play.

Atlantic Canada

At December 31, 2009, EnCana held an interest in approximately 76,000 gross acres (32,000 net acres) in Atlantic Canada, which includes Nova Scotia and Newfoundland and Labrador. EnCana operates five of its eight licenses in these areas and has an average working interest of approximately 42 percent.

EnCana is the operator of the Deep Panuke gas field, located offshore Nova Scotia, and owned and operated 100 percent of the field at December 31, 2009, after acquiring all of the interests in the licenses making up the field in July 2009. The Deep Panuke natural gas project involves the installation of the facilities required to produce natural gas from the field, located approximately 250 kilometres southeast of Halifax (on the Scotian shelf). Produced gas will be transported to shore by subsea pipeline and EnCana will transport this natural gas via the Maritimes & Northeast Pipeline to a delivery point in eastern Canada. Work has been progressing in anticipation of first production by mid 2011.

USA Division

The USA Division includes EnCana’s natural gas assets in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado and the East Texas and Fort Worth basins in Texas. The USA Division is also focused on exploration and development of the Haynesville shale in Texas and Louisiana and the Marcellus shale in Pennsylvania. The majority of the production in the U.S. is from the following four key resource plays: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth.

In 2009, the USA Division had total capital investment of approximately $1,821 million and drilled approximately 390 net wells. At December 31, 2009, EnCana’s landholdings in the U.S. were approximately 4.3 million gross acres (3.5 million net acres). Approximately 3.5 million gross acres were undeveloped (2.9 million net acres), with the majority in Texas, Colorado, Louisiana and Wyoming. The USA Division’s 2009 production averaged approximately 1,684 million cubic feet equivalent per day. The 2009 average production volumes were lowered by approximately 200 million cubic feet equivalent per day, due to shut-in and curtailed production and delayed well completions and tie-ins as a result of the low natural gas price environment.

The following tables summarize the USA Division landholdings, daily production and producing wells as at and for the periods indicated.

Landholdings

(thousands of acres at December 31, 2009)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Jonah	18	16	125	111	143	127	89%
Piceance	253	235	699	634	952	869	91%
East Texas	102	71	224	196	326	267	82%
Fort Worth	63	58	29	18	92	76	83%
Haynesville Shale	71	50	570	379	641	429	67%
Other	242	153	1,881	1,539	2,123	1,692	80%
USA Division	749	583	3,528	2,877	4,277	3,460	81%

Production

(annual average)	Natural Gas (MMcf/d)		Liquids (bbls/d)		Total (MMcfe/d)	
	2009	**2008**	**2009**	**2008**	**2009**	**2008**
Jonah	571	603	5,067	5,273	601	635
Piceance	362	385	1,760	2,513	373	400
East Texas	324	334	57	134	324	335
Fort Worth	136	142	435	500	139	145
Haynesville Shale	70	9	132	64	71	10
Other	153	160	3,866	4,866	176	188
USA Division	1,616	1,633	11,317	13,350	1,684	1,713

Producing Wells

(number of wells at December 31, 2009) (1)	Natural Gas		Crude Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Jonah	1,127	992	-	-	1,127	992
Piceance	2,921	2,557	3	-	2,924	2,557
East Texas	724	454	3	1	727	455
Fort Worth	774	652	15	14	789	666
Haynesville Shale	226	102	3	1	229	103
Other	1,953	1,379	12	7	1,965	1,386
USA Division	7,725	6,136	36	23	7,761	6,159

Note:

(1) Figures exclude wells capable of producing, but not producing, as of December 31, 2009.

Key Resource Plays and Activities in the USA Division

Jonah

The Jonah field is a key resource play located in the Green River Basin in southwest Wyoming. Production is 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 and 2009, EnCana conducted development in the adjacent normally pressured lands. At December 31, 2009, EnCana controlled approximately 125,000 undeveloped gross acres (111,000 net acres).

Within the over-pressured area, EnCana plans to drill the field to ten acre spacing with higher densities in some areas. Outside of the over-pressured area, EnCana owns approximately 120,000 gross acres, where 40 acre and possibly 20 acre drilling potential exists.

In 2009, EnCana drilled approximately 100 net wells within the core area and eight net wells in the adjacent lands. The Jonah field produced an average of approximately 571 million cubic feet per day of natural gas production.

Piceance

The Piceance Basin is a key resource play located in northwest Colorado. The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. EnCana's 2004 acquisition of Tom Brown, Inc. provided a significant amount of the acreage under current development. At December 31, 2009, EnCana controlled approximately 699,000 undeveloped gross acres (634,000 net acres).

Between 2006 and 2009, EnCana finalized eight agreements to jointly develop portions of the Piceance Basin. During 2009, EnCana drilled approximately 91 net wells with third party funds. For the period of 2010 to 2013, it is expected that EnCana will drill approximately 344 net wells with third party funds from all existing agreements.

Compression and processing facilities in the Piceance Basin include approximately 2,500 kilometres of pipelines and a processing facility with a capacity of approximately 60 million cubic feet per day. In addition, EnCana has access to third party processing facilities within the Piceance Basin.

In 2009, EnCana drilled approximately 129 net wells and produced an average of approximately 362 million cubic feet per day of natural gas.

East Texas

East Texas is a key resource play characterized as a tight gas play with multi-zone targets in the Bossier and Cotton Valley zones. 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. At December 31, 2009, EnCana controlled approximately 224,000 undeveloped gross acres (196,000 net acres).

In 2009, EnCana drilled approximately 38 net wells and produced an average of approximately 324 million cubic feet per day of natural gas.

Fort Worth

The Fort Worth Basin is a key resource play located in north Texas, producing from the prolific Barnett shale. Since entering the basin in 2003, EnCana has applied horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. At December 31, 2009, EnCana controlled approximately 29,000 undeveloped gross acres (18,000 net acres).

In 2009, EnCana drilled approximately 26 net wells and produced an average of approximately 136 million cubic feet per day of natural gas.

Haynesville Shale

EnCana has established a leading 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 to explore and develop the lands. In 2008, EnCana increased its leased acreage in the Haynesville shale play to approximately 435,000 net acres through a series of transactions totaling approximately $1,010 million. Included in this land position is approximately 63,000 net acres of mineral rights that were purchased by EnCana in July 2008 for approximately $300 million, net to EnCana. At December 31, 2009, EnCana controlled approximately 570,000 undeveloped gross acres (379,000 net acres), with the majority of the leaseholds in North Louisiana being located in the DeSoto and Red River parishes. Certain Haynesville shale undeveloped acreage is subject to leases that will expire over the next several years unless production is established on the acreage held. EnCana's near term drilling plans are focused on land retention and completion optimization.

At the end of 2009, EnCana finalized a joint venture with an unrelated party to develop part of the Haynesville shale in east Texas.

In 2009, EnCana drilled approximately 49 net wells and produced an average of approximately 70 million cubic feet per day of natural gas. The December 2009 exit rate production for the Haynesville shale was approximately 125 million cubic feet per day.

Marcellus Shale

In 2009, EnCana established an entry level land position of approximately 19,000 net undeveloped acres in the Marcellus shale in Pennsylvania through a joint venture agreement with an unrelated party. In 2010, EnCana will begin evaluating these lands.

Other Operations

Canada – Other

Canada – Other includes the results from the former Canadian Plains Division and former Integrated Oil – Canada operations which were transferred to Cenovus as part of the Split Transaction on November 30, 2009. Canada – Other included established natural gas development and production activities in southern Alberta and southern Saskatchewan, crude oil development and production activities in Alberta and Saskatchewan as well as exploration for, and development and production of bitumen using enhanced oil recovery methods in Alberta. Five key resource plays were contained in Canada - Other: (i) Shallow Gas in southeast Alberta and Saskatchewan; (ii) Pelican Lake in northeast Alberta; (iii) Weyburn in Saskatchewan; (iv) Foster Creek in northeast Alberta; and (v) Christina Lake in northeast Alberta. The Foster Creek and Christina Lake enhanced oil recovery projects were part of the integrated oil business created by EnCana and ConocoPhillips in January 2007.

For 2009, Canada – Other had combined capital investment of approximately $848 million (2008 - $1,500 million) and had drilled approximately 639 net wells (2008 - 1,514 net wells). For 2009, natural gas production was approximately 762 million cubic feet per day (2008 - 905 million cubic feet per day) and liquids production was approximately 99,900 barrels per day (2008 - 100,250 barrels per day).

Except where indicated otherwise, the financial, production and other operating data for EnCana in this annual information form as at dates prior to, or for periods entirely or partly prior to, the Split Transaction have not been adjusted to remove the results associated with Canada – Other (former Canadian Plains Division and former Integrated Oil Division – Canada operations) assets which were transferred to Cenovus under the Split

Transaction. Canada – Other results are reported as continuing operations in accordance with the full cost accounting requirements.

Former U.S. Downstream Refining

Prior to the Split Transaction, EnCana's Integrated Oil Division was comprised of the Integrated Oil – Canada operations and U.S. Downstream Refining. U.S. Downstream Refining focused on the refining of crude oil into petroleum and chemical products at the Borger refinery located in Borger, Texas and the Wood River refinery located in Roxana, Illinois. The refineries were acquired through the creation of the integrated oil business between EnCana and ConocoPhillips in January 2007. The refineries were 50 percent owned by EnCana and operated by ConocoPhillips. U.S. Downstream Refining was transferred to Cenovus as part of the Split Transaction on November 30, 2009.

For 2009, U.S. Downstream Refining had capital investment of approximately $829 million (2008 - $478 million). The expenditures primarily related to the Wood River refinery's CORE project. For the period ended September 30, 2009, the refineries' gross crude oil capacity was approximately 452 thousand barrels per day (year ended December 31, 2008 - 452 thousand barrels per day) and crude utilization was approximately 90 percent (year ended December 31, 2008 - 93 percent).

The U.S. Downstream Refining results prior to the Split Transaction are reported as discontinued operations for financial reporting purposes.

Market Optimization

Market Optimization activities are managed by EnCana's Midstream, Marketing & Fundamentals Corporate Group. 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.

Natural Gas Marketing

EnCana's produced natural gas is primarily marketed to local distribution companies, industrials, other producers, and energy marketing companies. Prices received by EnCana are based primarily upon prevailing index prices for natural gas in the region in which it is sold. 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 future cash flows by entering into various risk management contracts relating to produced natural gas. Details of those contracts related to EnCana's various risk management positions are found in Note 20 to EnCana's audited consolidated financial statements for the year ended December 31, 2009.

Other Marketing Activities

EnCana sells and manages the transportation of its crude oil, condensate and NGLs to markets in Canada and the U.S. Sales are normally executed under spot, monthly evergreen and term contracts with delivery to major pipeline/sales hubs at current market prices. In addition, EnCana holds interests in two power assets, the Cavalier and Balzac Power Stations, to optimize its electricity costs, particularly in Alberta.

Reserve Quantities and Other Oil and Gas Information

Since inception, EnCana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of EnCana's natural gas and liquids reserves annually. In 2009, 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's Vice President, Corporate Reserves & Competitor Analysis and four other staff under this individual's direction oversee the preparation of the reserves estimates by the IQREs. Currently this internal staff of three professional engineers, an engineering technologist and a business analyst have combined relevant experience of over 85 years. The Vice President and other engineering staff are all members of the appropriate provincial or state professional associations and are members of various industry associations such as the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

EnCana has a Reserves Committee of independent board members which reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the IQREs.

The evaluations by the IQREs are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that the IQREs are in receipt of all relevant information. Reserves are estimated based on material balance analysis, decline analysis, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations. In the case of producing reserves, the emphasis is on decline analysis where volumetric analysis is considered to limit forecasts to reasonable levels. Non-producing reserves are estimated by analogy to producing offsets, with consideration of volumetric estimates of in place quantities.

EnCana provides disclosure of its reserves and other oil and gas information in accordance with U.S. disclosure requirements. See "Note Regarding Reserves Data and Other Oil and Gas Information". In 2009, the U.S. Securities and Exchange Commission ("SEC") amended its oil and gas reporting requirements effective for EnCana's 2009 year end reporting. The U.S. Financial Accounting Standards Board ("FASB") also amended its oil and gas reserve estimation and disclosure requirements to align with the amended SEC requirements. The amendments included changing the price used to calculate reserves from a year-end single day price to a historical 12-month average price and permitting optional disclosure of the sensitivity of reserves to price.

Net Proved Reserves

EnCana's natural gas reserves decreased by approximately 19 percent in 2009, largely as a result of low 12-month average prices and the Split Transaction. Approximately 75 percent of the decrease attributable to negative revisions was a direct result of low 12-month average prices and approximately 80 percent of the sale of reserves in place was associated with the Split Transaction. Technical revisions were not significant. Extensions and discoveries were 2,132 billion cubic feet, of which approximately two-thirds was in the U.S. and the balance was in Canada.

During 2008, EnCana's natural gas reserves increased by approximately 3 percent as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,966 billion cubic feet. 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, natural gas reserves increased primarily from development drilling.

In 2009, EnCana's crude oil and natural gas liquids reserves decreased by approximately 77 percent and EnCana's bitumen reserves were divested, substantially all as a result of the Split Transaction.

At year-end 2008, EnCana's crude oil and natural gas liquids reserves, including bitumen, increased approximately 8 percent 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 natural gas liquids reserves, including bitumen, 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 natural gas liquids reserves, including bitumen, increased approximately 26 percent over the balance of the year, mainly due to bookings at Foster Creek and Christina Lake.

In keeping with U.S. standards requiring that the reserves and related future net revenue be estimated under existing economic conditions, operating methods and government regulations, 2008 and 2007 reserves and future net revenues were determined based on the year-end single day product prices. Under the amended SEC rules, the 2009 reserves and future net revenues have been determined based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Reference prices for 2009 were as follows: natural gas - Henry Hub $3.87/MMbtu, AECO C$3.77/MMbtu, decreases of 32 percent and 39 percent from year-end 2008, respectively; crude oil - WTI $61.18/bbl, Edmonton Light C$65.64/bbl, increases of 37 percent and 48 percent from year-end 2008, respectively.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards. The year-end 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)			Bitumen [3] (millions of barrels)
	Canada	United States	Total	Canada [4]	United States	Total	Canada
2007							
Beginning of year	7,028	5,390	12,418	279.8	54.0	333.8	799.6
Revisions and improved recovery	87	78	165	12.8	3.6	16.4	62.7
Extensions and discoveries	949	827	1,776	13.8	5.9	19.7	142.0
Purchase of reserves in place	63	211	274	0.2	-	0.2	-
Sale of reserves in place	(24)	(7)	(31)	(0.2)	-	(0.2)	(398.0) [4]
Production	(811)	(491)	(1,302)	(33.0)	(5.2)	(38.2)	(10.8)
End of year	7,292	6,008	13,300	273.4	58.3	331.7	595.5
Developed	4,868	3,368	8,236	217.8	37.0	254.8	71.7
Undeveloped	2,424	2,640	5,064	55.6	21.3	76.9	523.8
Total	7,292	6,008	13,300	273.4	58.3	331.7	595.5
2008							
Beginning of year	7,292	6,008	13,300	273.4	58.3	331.7	595.5
Revisions and improved recovery	148	(166)	(18)	27.9	(3.6)	24.3	84.9
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)	(32.0)	(4.9)	(36.9)	(12.0)
End of year	7,847	5,831	13,678	285.6	51.6	337.2	668.4
Developed	4,945	3,720	8,665	208.5	33.9	242.4	125.9
Undeveloped	2,902	2,111	5,013	77.1	17.7	94.8	542.5
Total	7,847	5,831	13,678	285.6	51.6	337.2	668.4
2009 [5]							
Beginning of year	7,847	5,831	13,678	285.6	51.6	337.2	668.4
Revisions and improved recovery [6]	(755)	(845)	(1,600)	7.3	(12.6)	(5.3)	(87.6)
Extensions and discoveries	726	1,406	2,132	12.5	6.5	19.0	159.4
Purchase of reserves in place	28	-	28	0.5	-	0.5	-
Sale of reserves in place [7]	(1,772)	(89)	(1,861)	(243.2)	(0.2)	(243.4)	(725.1)
Production	(725)	(590)	(1,315)	(27.2)	(4.1)	(31.3)	(15.1)
End of year	5,349	5,713	11,062	35.5	41.2	76.7	-
Developed	2,927	3,571	6,498	25.1	25.8	50.9	-
Undeveloped	2,422	2,142	4,564	10.4	15.4	25.8	-
Total	5,349	5,713	11,062	35.5	41.2	76.7	-

Notes:

(1) Definitions:

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

b. “Proved” oil and gas reserves are those quantities of oil and gas which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. “Developed” oil and gas reserves are reserves of any category that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

d. “Undeveloped” oil and gas reserves are reserves of any category 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 natural gas and liquids reserves with any U.S. federal authority or agency other than the SEC.

(3) EnCana's disclosure of bitumen reserve volumes is in accordance with amended SEC rules regarding disclosure by final products. 2008 and 2007 crude oil and natural gas liquids totals have been revised to exclude bitumen volumes.

(4) Contribution of bitumen interests to the integrated oil business with ConocoPhilips.

(5) The estimates of reserves for the year-end 2009 differ from those that were determined in previous years, which were determined by employing year-end single day pricing. Single day prices as at December 31, 2009 were as follows: natural gas – Henry Hub $5.78/Mmbtu and AECO C$5.63/MMbtu, which were approximately 49 percent higher than the 12-month average prices; crude oil – WTI $79.36/bbl and Edmonton Light C$82.69/bbl, which were approximately 30 percent and 26 percent higher than the 12-month average prices, respectively. The 2009 reserve estimates for natural gas and crude oil and natural gas liquids using the year-end single day pricing would have been higher by approximately 11 percent and 7 percent respectively, than those reported pursuant to the amended SEC rules utilizing the 12-month average price.

(6) Revisions and improved recovery includes revisions due to price. Approximately 75 percent of the negative revisions to natural gas in 2009 were attributable to the significantly lower prices in effect for SEC reporting purposes.

(7) The transfer of EnCana's Canadian Plains and Integrated Oil Divisions' upstream assets to Cenovus, effective November 30, 2009 pursuant to the Split Transaction, accounts for approximately 80 percent of the sale of reserves in place for natural gas and substantially all of the sale of reserves in place for crude oil and natural gas liquids and for bitumen.

Proved Undeveloped Reserves

EnCana's proved undeveloped natural gas reserves represented approximately 41 percent of total proved natural gas reserves at December 31, 2009, up from approximately 37 percent at December 31, 2008. At December 31, 2009, approximately 34 percent of EnCana's proved crude oil and liquids reserves were proved undeveloped, up from approximately 28 percent at December 31, 2008. These increases were largely a result of the transfer of assets with lower levels of proved undeveloped reserves as part of the Split Transaction.

During 2009, approximately 633 billion cubic feet equivalent of proved undeveloped reserves were converted to proved developed. Investments made during 2009 to convert proved undeveloped reserves to proved developed reserves were approximately $1.2 billion. Proved undeveloped reserves increased by approximately 260 billion cubic feet of natural gas as a result of amendments to the SEC rules relating to estimates of proved undeveloped reserves.

At December 31, 2009, the proved undeveloped reserves which have remained undeveloped for five years or more in both Canada and the United States were not material. All of the proved undeveloped reserves at December 31, 2009 are scheduled for development within the next five years in both Canada and the United States.

Sensitivity of 2009 Reserves to Prices

The following table summarizes EnCana's estimates of its proved reserves as at December 31, 2009 based on the 2009 12-month average prices ("SEC case") and on the prices set forth below.

	Natural Gas (billions of cubic feet)			**Crude Oil and Natural Gas Liquids** (millions of barrels)		
	Canada	**United States**	**Total**	**Canada**	**United States**	**Total**
Price Case						
SEC case	5,349	5,713	11,062	35.5	41.2	76.7
Business case	5,675	6,605	12,280	37.2	45.1	82.3
Difference versus SEC case	6.1%	15.6%	11.0%	4.9%	9.5%	7.4%

The business case assumes the following prices: natural gas – Henry Hub $5.50/MMbtu in 2010 and $6.50/MMbtu thereafter, and AECO C$5.49/MMbtu in 2010 and C$6.39/MMbtu in 2011 decreasing to C$6.04/MMbtu by 2014 and thereafter; crude oil – WTI $75.00/bbl and Edmonton Light C$76.84/bbl.

Production Volumes

The following tables summarize the net daily average production volumes for EnCana for the periods indicated.

Production Volumes by Current Divisions	2009				
	Annual	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*					
Canadian Division [1]	1,224	1,071	1,201	1,343	1,281
USA Division	1,616	1,616	1,524	1,581	1,746
	2,840	2,687	2,725	2,924	3,027
Liquids *(bbls/d)*					
Canadian Division [1]	15,880	12,477	15,909	17,624	17,567
USA Division	11,317	11,586	10,325	11,699	11,671
	27,197	24,063	26,234	29,323	29,238
Total Canadian & USA Divisions *(MMcfe/d)*	3,003	2,831	2,883	3,100	3,203
Canadian Division Total [1] *(MMcfe/d)*	1,319	1,145	1,297	1,449	1,387
USA Division Total *(MMcfe/d)*	1,684	1,686	1,586	1,651	1,816
	3,003	2,831	2,883	3,100	3,203

Production Volumes by Country	2009				
	Annual	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*					
Canada [2]	1,986	1,588	2,027	2,207	2,123
United States	1,616	1,616	1,524	1,581	1,746
	3,602	3,204	3,551	3,788	3,869
Liquids *(bbls/d)*					
Canada [2]	115,780	87,859	128,937	123,954	122,609
United States	11,317	11,586	10,325	11,699	11,671
	127,097	99,445	139,262	135,653	134,280
Total EnCana *(MMcfe/d)*					
Canada [2]	2,681	2,115	2,801	2,951	2,859
United States	1,684	1,686	1,586	1,651	1,816
	4,365	3,801	4,387	4,602	4,675
Total EnCana *(BOE/d)*					
Canada [2]	446,780	352,526	466,770	491,787	476,442
United States	280,650	280,919	264,325	275,199	302,671
	727,430	633,445	731,095	766,986	779,113

Notes:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

(2) Results prior to November 30, 2009 include production from Canada – Other.

Production Volumes by Current Divisions	Annual Average	
	2008	**2007**
Produced Gas *(MMcf/d)*		
Canadian Division [(1)]	1,300	1,255
USA Division	1,633	1,345
	2,933	2,600
Liquids *(bbls/d)*		
Canadian Division [(1)]	19,980	18,272
USA Division	13,350	14,180
	33,330	32,452
Total Canadian & USA Divisions *(MMcfe/d)*	3,132	2,795
Canadian Division Total [(1)] *(MMcfe/d)*	1,419	1,365
USA Division Total *(MMcfe/d)*	1,713	1,430
	3,132	2,795

Production Volumes by Country	Annual Average	
	2008	**2007**
Produced Gas *(MMcf/d)*		
Canada [(2)]	2,205	2,221
United States	1,633	1,345
	3,838	3,566
Liquids *(bbls/d)*		
Canada [(2)]	120,230	119,974
United States	13,350	14,180
	133,580	134,154
Total EnCana *(MMcfe/d)*		
Canada [(2)]	2,926	2,941
United States	1,713	1,430
	4,639	4,371
Total EnCana *(BOE/d)*		
Canada [(2)]	487,730	490,141
United States	285,517	238,347
	773,247	728,488

Notes:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

(2) Results prior to November 30, 2009 include production from Canada – Other.

Per-Unit Results

The following tables summarize the net per-unit results for EnCana for the periods indicated, which exclude the impact of realized hedging.

Netbacks by Current Divisions

	2009				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *($/Mcf)*					
Canadian Division [1]					
Price	3.71	4.21	2.92	3.19	4.58
Production and mineral taxes	0.03	-	0.02	0.04	0.03
Transportation and selling	0.33	0.40	0.35	0.30	0.30
Operating	1.13	1.43	1.09	1.02	1.04
	2.22	2.38	1.46	1.83	3.21
USA Division					
Price	3.75	4.64	3.41	3.01	3.88
Production and mineral taxes	0.17	0.23	0.08	0.08	0.27
Transportation and selling	0.90	0.96	0.99	0.87	0.78
Operating	0.55	0.61	0.56	0.54	0.51
	2.13	2.84	1.78	1.52	2.32
Total Canadian & USA Divisions					
Price	3.73	4.47	3.19	3.09	4.18
Production and mineral taxes	0.11	0.14	0.06	0.06	0.17
Transportation and selling	0.66	0.74	0.71	0.61	0.58
Operating	0.80	0.93	0.79	0.76	0.74
	2.16	2.66	1.63	1.66	2.69
Liquids *($/bbl)*					
Canadian Division [1]					
Price	47.86	60.37	52.48	45.86	36.51
Production and mineral taxes	0.45	0.34	0.48	0.47	0.47
Transportation and selling	1.06	0.49	1.41	0.62	1.61
Operating	3.62	3.25	3.04	4.09	3.94
	42.73	56.29	47.55	40.68	30.49
USA Division					
Price	48.56	64.39	55.60	47.27	27.43
Production and mineral taxes	4.39	5.84	5.12	4.18	2.48
Transportation and selling	-	-	-	-	-
Operating	-	-	-	-	-
	44.17	58.55	50.48	43.09	24.95
Total Canadian & USA Divisions					
Price	48.15	62.31	53.71	46.42	32.88
Production and mineral taxes	2.09	2.99	2.31	1.95	1.27
Transportation and selling	0.62	0.26	0.85	0.38	0.96
Operating	2.11	1.68	1.84	2.46	2.37
	43.33	57.38	48.71	41.63	28.28
Total Netback *($/Mcfe)*					
Canadian Division [1]					
Price	4.02	4.59	3.36	3.51	4.70
Production and mineral taxes	0.03	0.01	0.02	0.04	0.04
Transportation and selling	0.32	0.38	0.34	0.28	0.30
Operating	1.09	1.37	1.05	0.99	1.01
	2.58	2.83	1.95	2.20	3.35
USA Division					
Price	3.92	4.89	3.64	3.21	3.91
Production and mineral taxes	0.19	0.26	0.11	0.10	0.28
Transportation and selling	0.86	0.92	0.95	0.83	0.75
Operating	0.53	0.58	0.54	0.52	0.49
	2.34	3.13	2.04	1.76	2.39
Total Canadian & USA Divisions					
Price	3.96	4.77	3.51	3.35	4.25
Production and mineral taxes	0.12	0.16	0.07	0.08	0.17
Transportation and selling	0.63	0.70	0.68	0.58	0.56
Operating	0.78	0.90	0.76	0.74	0.72
	2.43	3.01	2.00	1.95	2.80

Note:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Netbacks by Country

	2009				
	Annual	Q4	Q3	Q2	Q1
Produced Gas *($/Mcf)*					
Canada [1]					
Price	3.64	4.02	2.89	3.20	4.51
Production and mineral taxes	0.04	0.03	0.03	0.05	0.04
Transportation and selling	0.26	0.31	0.26	0.23	0.24
Operating	0.98	1.17	0.96	0.89	0.94
	2.36	2.51	1.64	2.03	3.29
United States					
Price	3.75	4.64	3.41	3.01	3.88
Production and mineral taxes	0.17	0.23	0.08	0.08	0.27
Transportation and selling	0.90	0.96	0.99	0.87	0.78
Operating	0.55	0.61	0.56	0.54	0.51
	2.13	2.84	1.78	1.52	2.32
Total EnCana					
Price	3.69	4.34	3.11	3.12	4.23
Production and mineral taxes	0.10	0.13	0.05	0.06	0.14
Transportation and selling	0.55	0.64	0.58	0.50	0.49
Operating	0.79	0.89	0.78	0.75	0.75
	2.25	2.68	1.70	1.81	2.85
Liquids *($/bbl)*					
Canada [1]					
Price	49.75	61.96	57.54	49.31	32.48
Production and mineral taxes	0.63	0.55	0.62	0.57	0.77
Transportation and selling	1.53	1.14	1.66	1.69	1.50
Operating	9.21	9.56	8.96	9.16	9.29
	38.38	50.71	46.30	37.89	20.92
United States					
Price	48.56	64.39	55.60	47.27	27.43
Production and mineral taxes	4.39	5.84	5.12	4.18	2.48
Transportation and selling	-	-	-	-	-
Operating	-	-	-	-	-
	44.17	58.55	50.48	43.09	24.95
Total EnCana					
Price	49.65	62.25	57.40	49.14	32.03
Production and mineral taxes	0.97	1.18	0.95	0.88	0.92
Transportation and selling	1.39	1.01	1.54	1.55	1.36
Operating	8.39	8.43	8.30	8.38	8.46
	38.90	51.63	46.61	38.33	21.29
Total Netback *($/Mcfe)*					
Canada [1]					
Price	4.84	5.59	4.78	4.47	4.74
Production and mineral taxes	0.05	0.04	0.05	0.06	0.06
Transportation and selling	0.26	0.28	0.27	0.25	0.24
Operating	1.12	1.27	1.11	1.05	1.09
	3.41	4.00	3.35	3.11	3.35
United States					
Price	3.92	4.89	3.64	3.21	3.91
Production and mineral taxes	0.19	0.26	0.11	0.10	0.28
Transportation and selling	0.86	0.92	0.95	0.83	0.75
Operating	0.53	0.58	0.54	0.52	0.49
	2.34	3.13	2.04	1.76	2.39
Total EnCana					
Price	4.49	5.28	4.36	4.02	4.42
Production and mineral taxes	0.11	0.14	0.07	0.08	0.15
Transportation and selling	0.49	0.57	0.52	0.46	0.44
Operating	0.89	0.97	0.90	0.86	0.86
	3.00	3.60	2.87	2.62	2.97

Note:
(1) Results prior to November 30, 2009 include production from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Netbacks by Current Divisions

	Annual Average	
	2008	**2007**
Produced Gas *($/Mcf)*		
Canadian Division [(1)]		
Price	8.12	6.30
Production and mineral taxes	0.06	0.08
Transportation and selling	0.42	0.42
Operating	1.15	1.05
	6.49	4.75
USA Division		
Price	7.89	5.38
Production and mineral taxes	0.56	0.34
Transportation and selling	0.84	0.62
Operating	0.59	0.65
	5.90	3.77
Total Canadian & USA Divisions		
Price	7.99	5.82
Production and mineral taxes	0.34	0.21
Transportation and selling	0.66	0.53
Operating	0.84	0.84
	6.15	4.24
Liquids *($/bbl)*		
Canadian Division [(1)]		
Price	85.12	61.73
Production and mineral taxes	0.63	0.47
Transportation and selling	1.64	1.43
Operating	5.41	4.88
	77.44	54.95
USA Division		
Price	83.18	59.83
Production and mineral taxes	7.25	4.28
Transportation and selling	-	0.01
Operating	-	-
	75.93	55.54
Total Canadian & USA Divisions		
Price	84.38	60.90
Production and mineral taxes	3.27	2.12
Transportation and selling	0.98	0.81
Operating	3.40	3.08
	76.73	54.89
Total Netback *($/Mcfe)*		
Canadian Division [(1)]		
Price	8.63	6.62
Production and mineral taxes	0.06	0.08
Transportation and selling	0.41	0.40
Operating	1.13	1.03
	7.03	5.11
USA Division		
Price	8.17	5.65
Production and mineral taxes	0.59	0.36
Transportation and selling	0.80	0.59
Operating	0.56	0.62
	6.22	4.08
Total Canadian & USA Divisions		
Price	8.38	6.12
Production and mineral taxes	0.35	0.22
Transportation and selling	0.62	0.50
Operating	0.82	0.82
	6.59	4.58

Note:
(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Netbacks by Country

	Annual Average	
	2008	2007
Produced Gas *($/Mcf)*		
Canada [1]		
Price	7.97	6.20
Production and mineral taxes	0.08	0.09
Transportation and selling	0.35	0.35
Operating	1.03	0.92
	6.51	4.84
United States		
Price	7.89	5.38
Production and mineral taxes	0.56	0.34
Transportation and selling	0.84	0.62
Operating	0.59	0.65
	5.90	3.77
Total EnCana		
Price	7.94	5.89
Production and mineral taxes	0.28	0.18
Transportation and selling	0.56	0.45
Operating	0.84	0.82
	6.26	4.44
Liquids *($/bbl)*		
Canada [1]		
Price	75.85	48.92
Production and mineral taxes	1.01	0.72
Transportation and selling	1.70	1.68
Operating	10.57	9.47
	62.57	37.05
United States		
Price	83.18	59.83
Production and mineral taxes	7.25	4.28
Transportation and selling	-	0.01
Operating	-	-
	75.93	55.54
Total EnCana		
Price	76.58	50.05
Production and mineral taxes	1.63	1.08
Transportation and selling	1.53	1.51
Operating	9.55	8.57
	63.87	38.89
Total Netback *($/Mcfe)*		
Canada [1]		
Price	9.13	6.69
Production and mineral taxes	0.10	0.09
Transportation and selling	0.33	0.33
Operating	1.21	1.08
	7.49	5.19
United States		
Price	8.17	5.65
Production and mineral taxes	0.59	0.36
Transportation and selling	0.80	0.59
Operating	0.56	0.62
	6.22	4.08
Total EnCana		
Price	8.77	6.35
Production and mineral taxes	0.28	0.18
Transportation and selling	0.50	0.42
Operating	0.97	0.93
	7.02	4.82

Note:

(1) Results prior to November 30, 2009 include production from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

The following tables summarize the impact of realized hedging on EnCana's netbacks.

Impact of Realized Hedging on EnCana's Canadian & USA Divisions Netbacks (1)

	2009				
	Annual	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	3.30	1.97	4.25	3.93	3.04
Liquids *($/bbl)*	(0.01)	-	-	-	(0.03)
Total *($/Mcfe)*	3.12	1.87	4.02	3.70	2.87

	Annual Average	
	2008	2007
Natural Gas *($/Mcf)*	0.07	1.55
Liquids *($/bbl)*	(3.65)	(1.90)
Total *($/Mcfe)*	0.03	1.42

Impact of Realized Hedging on EnCana's Total Netbacks (2)

	2009				
	Annual	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	3.33	2.11	4.20	3.87	2.99
Liquids *($/bbl)*	0.83	(0.14)	(0.01)	1.09	2.21
Total *($/Mcfe)*	2.77	1.78	3.39	3.21	2.55

	Annual Average	
	2008	2007
Natural Gas *($/Mcf)*	(0.02)	1.33
Liquids *($/bbl)*	(5.46)	(3.05)
Total *($/Mcfe)*	(0.17)	0.99

Notes:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

(2) Results prior to November 30, 2009, include production from Canada – Other.

Drilling Activity

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

Exploration Wells Drilled [1,2]

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2009											
Canadian Division	34	24	1	1	-	-	35	25	25	60	25
USA Division	8	4	-	-	1	-	9	4	-	9	4
	42	28	1	1	1	-	44	29	25	69	29
Canada – Other [3]	-	-	4	4	-	-	4	4	8	12	4
Other	-	-	-	-	-	-	-	-	-	-	-
Total	42	28	5	5	1	-	48	33	33	81	33
2008											
Canadian Division	70	54	8	5	-	-	78	59	69	147	59
USA Division	26	14	-	-	-	-	26	14	-	26	14
	96	68	8	5	-	-	104	73	69	173	73
Canada – Other [3]	5	3	1	1	2	1	8	5	34	42	5
Other	-	-	-	-	3	1	3	1	-	3	1
Total	101	71	9	6	5	2	115	79	103	218	79
2007											
Canadian Division	116	92	4	3	-	-	120	95	91	211	95
USA Division	2	2	-	-	-	-	2	2	-	2	2
	118	94	4	3	-	-	122	97	91	213	97
Canada – Other [3]	4	4	3	3	-	-	7	7	89	96	7
Other	-	-	-	-	4	3	4	3	-	4	3
Total	122	98	7	6	4	3	133	107	180	313	107

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) Includes wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These assets were transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Development Wells Drilled [1,2]

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2009 [3]											
Canadian Division	731	672	3	2	-	-	734	674	143	877	674
USA Division	495	382	-	-	5	4	500	386	55	555	386
	1,226	1,054	3	2	5	4	1,234	1,060	198	1,432	1,060
Canada – Other [4]	560	507	144	120	8	8	712	635	255	967	635
Total	1,786	1,561	147	122	13	12	1,946	1,695	453	2,399	1,695
2008											
Canadian Division	1,088	989	17	16	-	-	1,105	1,005	329	1,434	1,005
USA Division	904	736	-	-	-	-	904	736	378	1,282	736
	1,992	1,725	17	16	-	-	2,009	1,741	707	2,716	1,741
Canada – Other [4]	1,502	1,385	146	113	11	11	1,659	1,509	544	2,203	1,509
Total	3,494	3,110	163	129	11	11	3,668	3,250	1,251	4,919	3,250
2007											
Canadian Division	1,528	1,425	20	18	1	1	1,549	1,444	325	1,874	1,444
USA Division	809	641	-	-	1	1	810	642	36	846	642
	2,337	2,066	20	18	2	2	2,359	2,086	361	2,720	2,086
Canada – Other [4]	2,221	2,117	216	167	10	7	2,447	2,291	509	2,956	2,291
Total	4,558	4,183	236	185	12	9	4,806	4,377	870	5,676	4,377

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, 2009, EnCana was in the process of drilling the following exploratory and development wells: approximately 5 gross wells (5 net wells) in Canada and approximately 60 gross wells (48 net wells) in the U.S.

(4) Includes wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These assets were transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2009.

	Gas		Oil		Total [1,2]	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	10,814	9,759	398	225	11,212	9,984
British Columbia	2,133	1,980	15	11	2,148	1,991
Total Canada	12,947	11,739	413	236	13,360	11,975
Colorado	5,107	4,482	6	2	5,113	4,484
Texas	1,894	1,318	36	25	1,930	1,343
Wyoming	2,067	1,537	1	1	2,068	1,538
Utah	40	37	11	11	51	48
Louisiana	76	47	-	-	76	47
Kansas	1	1	-	-	1	1
Montana	1	1	-	-	1	1
Total United States	9,186	7,423	54	39	9,240	7,462
Total	22,133	19,162	467	275	22,600	19,437

Notes:

(1) EnCana has varying royalty interests in approximately 8,216 natural gas wells and approximately 5,480 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: approximately 11,155 gross natural gas wells (1,744 net wells) and approximately 146 gross crude oil wells (92 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2009.

Landholdings [1,2,3,4,5,6]		**Developed**		**Undeveloped**		**Total**	
(thousands of acres)		**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada							
Alberta	— Fee	2,467	2,467	1,611	1,611	4,078	4,078
	— Crown	1,312	741	1,394	1,098	2,706	1,839
	— Freehold	222	127	74	55	296	182
		4,001	3,335	3,079	2,764	7,080	6,099
British Columbia	— Crown	1,024	910	2,807	2,201	3,831	3,111
	— Freehold	-	-	7	-	7	-
		1,024	910	2,814	2,201	3,838	3,111
Newfoundland and Labrador	— Crown	-	-	35	2	35	2
Nova Scotia	— Crown	-	-	41	30	41	30
Northwest Territories	— Crown	-	-	45	12	45	12
Total Canada		5,025	4,245	6,014	5,009	11,039	9,254
United States							
Colorado	— Federal/State Lands	197	183	615	561	812	744
	— Freehold	105	96	131	120	236	216
	— Fee	3	3	31	31	34	34
		305	282	777	712	1,082	994
Texas	— Federal/State Lands	7	4	67	65	74	69
	— Freehold	229	170	987	793	1,216	963
	— Fee	-	-	4	2	4	2
		236	174	1,058	860	1,294	1,034
Wyoming	— Federal/State Lands	142	83	473	343	615	426
	— Freehold	15	8	28	15	43	23
		157	91	501	358	658	449
Louisiana	— Federal/State Lands	-	-	4	4	4	4
	— Freehold	28	16	514	325	542	341
	— Fee	13	11	75	51	88	62
		41	27	593	380	634	407
Other	— Federal/State Lands	9	8	342	329	351	337
	— Freehold	1	1	257	238	258	239
	— Fee	-	-	-	-	-	-
		10	9	599	567	609	576
Total United States		749	583	3,528	2,877	4,277	3,460
International							
Greenland		-	-	1,700	808	1,700	808
Azerbaijan		-	-	346	17	346	17
Australia		-	-	104	40	104	40
Total International		-	-	2,150	865	2,150	865
Total		5,774	4,828	11,692	8,751	17,466	13,579

Notes:

(1) Fee lands are those lands in which EnCana has a fee simple interest in the mineral rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest; or (iii) one or more substances or products that have not been leased. The current fee lands acreage summary includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

(2) This table excludes approximately 2.9 million gross acres of fee lands with one or more substances or products under lease or sublease, reserving to EnCana royalties or other interests.

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

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

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

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

Acquisitions, 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 2009, 2008 and 2007.

($ millions)	**2009**	**2008**	**2007**
Capital Investment			
Canadian Division	1,869	2,459	2,403
USA Division	1,821	2,682	1,935
	3,690	5,141	4,338
Market Optimization	2	17	6
Corporate & Other	85	165	154
	3,777	5,323	4,498
Acquisitions – Property			
Canadian Division	190	151	75
USA Division (1)	46	1,023	2,613
Corporate			
Canadian Division (2)	24	-	-
Divestitures			
Property			
Canadian Division (3)	(1,000)	(400)	(213)
USA Division	(73)	(251)	(10)
Corporate & Other (4)	(5)	(41)	(47)
Corporate			
Corporate & Other (5)	(83)	(165)	(211)
	2,876	5,640	6,705
Other			
Capital Investment - Canada – Other (6)	848	1,500	1,238
Acquisitions – Property - Canada – Other (6)	3	-	14
Divestitures – Property - Canada – Other (6)	(17)	(47)	-
Net Capital Investment Before Discontinued Operations	3,710	7,093	7,957
Discontinued Operations (7)	829	478	220
Net Capital Investment	4,539	7,571	8,177

Notes:

(1) In 2008, mainly includes Haynesville shale properties. In 2007, mainly includes the Deep Bossier natural gas assets and land interests.

(2) Acquisition of Kerogen Resources Canada, ULC in May 2009.

(3) Primarily includes divestures of non-core conventional oil and natural gas assets.

(4) In 2007, consists primarily of the sale of EnCana's office building project assets (The Bow) and the sale of Australia assets.

(5) In 2009, includes sale of Senlac Oil Limited. In 2008, mainly includes the sale of interests in Brazil. In 2007, sale of interests in Chad and Oman were completed.

(6) Canada – Other assets (former Canadian Plains and former Integrated Oil – Canada assets) were transferred to Cenovus as part of the Split Transaction.

(7) Includes U.S. Downstream Refining capital investments, which are reported as discontinued operations as these assets were transferred to Cenovus as part of the Split Transaction.

Delivery Commitments

As part of ordinary business operations, EnCana has a number of delivery commitments to provide natural gas under existing contracts and agreements. The Corporation has sufficient natural gas reserves to meet these commitments. More detailed information relating to such commitments can be found in the Contractual Obligations and Contingencies section of the Corporation's Management's Discussion and Analysis for the year ended December 31, 2009.

General

Competitive Conditions

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

Environmental Protection

EnCana's 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 environmental policy to the Board of Directors for approval 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.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2009, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material. 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 $3.8 billion. As at December 31, 2009, EnCana has recorded an asset retirement obligation of $787 million.

Social and Environmental Policies

EnCana has a Corporate Responsibility Policy (the "Policy") that outlines EnCana's commitment to deliver strong financial performance and sustainable value while conducting its business in an ethical and responsible way. 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. Coordination and oversight of the Policy resides with the EH&S, Security and Corporate Responsibility Group within Corporate Development, EH&S and Reserves.

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.

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, 2009, EnCana employed 3,797 full time equivalent employees as set forth in the following table.

	FTE Employees
Canadian Division	1,656
USA Division	1,581
Corporate	560
Total	3,797

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

Foreign Operations

As at December 31, 2009, 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.

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 & Municipality of Residence	Director Since [1]	Principal Occupation
David P. O'Brien, O.C. [5,7,10] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
Randall K. Eresman [8] Calgary, Alberta, Canada	2006	President & Chief Executive Officer EnCana Corporation
Claire S. Farley [2,3,6] Houston, Texas, U.S.A.	2008	Advisory Director Jefferies Randall & Dewey *(Global oil and gas energy industry advisor)*
Fred J. Fowler [3] Houston, Texas, U.S.A.	2010	Corporate Director
Barry W. Harrison [2,4,5,9] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
Suzanne P. Nimocks [2] Houston, Texas, U.S.A.	2010	Corporate Director
Jane L. Peverett [2,5,6] West Vancouver, British Columbia, Canada	2003	Corporate Director
Allan P. Sawin [2,3,4] Edmonton, Alberta, Canada	2007	President, Bear Investments Inc. *(Private investment company)*
Clayton H. Woitas [3,4,6] 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) Ex officio non-voting member of all other committees. As an ex officio non-voting member, Mr. O'Brien attends as his schedule permits and may vote when necessary to achieve a quorum.

(8) As an officer of EnCana and a non-independent director, Mr. Eresman is not a member of any Board committees.

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

(10) Mr. 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 nine directors of the Corporation. As a result of the Split Transaction on November 30, 2009, EnCana's former 13-member Board of Directors was split between the resulting companies, with six members becoming directors of Cenovus and seven members remaining as directors of EnCana. Each of the seven remaining directors were elected at the last annual meeting of shareholders held on April 22, 2009. Following the Split Transaction, two additional directors were appointed by the Board of Directors (Suzanne P. Nimocks and Fred J. Fowler) and the number of directors, as reflected in the above table, currently stands at nine. At the next annual and special meeting, shareholders will be asked to elect as directors the nine individuals listed in the above table, together with one new nominee, Mr. Peter A. Dea. 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 existing directors shall be eligible for re-election.

Executive Officers

Name & Municipality of Residence	**Corporate Office *(Divisional Title)***
Randall K. Eresman Calgary, Alberta, Canada	President & Chief Executive Officer
Sherri A. Brillon Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
Michael M. Graham Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Division)*
Robert A. Grant Calgary, Alberta, Canada	Executive Vice-President, Corporate Development, EH&S and Reserves
Eric D. Marsh Denver, Colorado, U.S.A.	Executive Vice-President, Natural Gas Economy
R. William Oliver Calgary, Alberta, Canada	Executive Vice-President & Chief Corporate Officer
William A. Stevenson Calgary, Alberta, Canada	Executive Vice-President & Chief Accounting Officer
Jeff E. Wojahn Denver, Colorado, U.S.A.	Executive Vice-President *(President, USA Division)*
Renee E. Zemljak Denver, Colorado, U.S.A.	Executive Vice-President, Midstream, Marketing & Fundamentals

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:

Ms. Farley has been an Advisory Director of Jefferies Randall & Dewey (global oil and gas energy industry advisor) since 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. Fowler has been Chairman of Spectra Energy Partners L.P. (public entity) since October 2008. He was President & Chief Executive Officer of Spectra Energy Corp. (public oil and gas company) from December 2006 to December 2008 and served as a director from December 2006 to May 2009. He was President & Chief Executive Officer of Duke Energy Gas Transmission, LLC (a subsidiary of Duke Energy Corporation) from April 2006 through December 2006. From June 1997, he occupied various executive positions with Duke Energy Corporation (public oil and gas company), including President & Chief Operating Officer from November 2002 through April 2006.

Ms. Nimocks was a director (senior partner) with McKinsey & Company (global management consulting firm) from June 1999 to March 2010 and was with the firm in various other capacities since 1989, including as a leader in the firm's Global Petroleum Practice, Electric Power & Natural Gas Practice, Organization Practice, and Risk Management Practice, as a member of the firm's worldwide personnel committees for many years and as the Houston Office Manager for eight years.

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. Sawin is President of Bear Investments Inc., a private investment company. From 1990 until their sale to CCS Income Trust in May 2006, he was President, director and part owner of Grizzly Well Servicing Inc. and related companies.

Mr. Dea is a nominee director who will stand for election at EnCana's April 21, 2010 Annual and Special Meeting of Shareholders. He has been President & Chief Executive Officer of Cirque Resources LP (private oil and gas company) since May 2007. From November 2001 through August 2006, he was President & Chief Executive Officer and a director of Western Gas Resources, Inc. (public natural gas company). He joined Barrett Resources Corporation (public natural gas company) in November 1993 and was CEO from November 1999 and Chairman of the Board from February 2000 through August 2001.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 10, 2010, directly or indirectly, or exercised control or direction over an aggregate of 503,999 Common Shares representing 0.07 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 4,381,389 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 D of this annual information form.

Composition of the Audit Committee

The Audit Committee consists of five members, all of whom are independent and financially literate in accordance with the definitions in National Instrument 52-110 *Audit Committees.* The relevant education and experience of each Audit Committee member is outlined below.

Claire S. Farley

Ms. Farley holds a Bachelor of Science in exploration geology (Emory University). She is a director of FMC Technologies, Inc. (public global oil and gas equipment and service company) and also serves on the Audit Committee. Ms. Farley has been an Advisory Director of Jefferies Randall & Dewey (global oil and gas energy industry advisor) since 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.

Barry W. Harrison

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.

Suzanne P. Nimocks

Ms. Nimocks holds a Bachelor of Arts in Economics (Tufts University) and a Masters in Business Administration (Harvard Graduate School of Business). She was a director (senior partner) with McKinsey & Company (global management consulting firm) from June 1999 to March 2010 and was with the firm in various other capacities since 1989, including as a leader in the firm’s Global Petroleum Practice, Electric Power & Natural Gas Practice, Organization Practice, and Risk Management Practice, as a member of the firm’s worldwide personnel committees for many years and as the Houston Office Manager for eight years.

Jane L. Peverett (Audit Committee Chair)

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 appointed a director of the Canadian Imperial Bank of Commerce in February 2009 and is a member of the Audit Committee. 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.

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 Chair of the Audit Committee (or if the Chair is unavailable, any other member of the Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP which have not otherwise been pre-approved by the Audit Committee, including the fees and terms of the proposed services ("Delegated Authority"). Any required determination about the Chair'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 2009 and 2008.

(C$ thousands)	**2009**	**2008**
Audit Fees (1)	3,963	4,060
Audit-Related Fees (2)	1,076	1,053
Tax Fees (3)	569	1,408
All Other Fees (4)	5	5
Total	5,613	6,526

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 2009 and 2008, the services provided in this category included an audit and reviews of Cenovus carve-out consolidated financial statements and related documents, reviews in connection with acquisitions and divestitures, research of accounting and audit-related issues, review of reserves disclosure and the review of the Corporate Responsibility Report.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2009 and 2008, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.

(4) During fiscal 2009 and 2008, 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 2008 or 2009.

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, 2009, there were approximately 751 million Common Shares outstanding and no Preferred Shares outstanding.

Common Shares

Under the Split Transaction, holders of Common Shares of EnCana received one new EnCana Common Share and one Common Share of Cenovus for each EnCana Common Share previously held.

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 that 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.

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, and the Second Preferred Shares are entitled to priority over 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, 2009.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")
Senior Unsecured			
Long-Term Rating	BBB+	Baa2	A (low)
Outlook	Stable	Stable	Stable
Commercial Paper			
Short-Term Rating	A-1 (low)	P-2	R-1 (low)
Outlook	Stable	Stable	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 BBB+ by S&P is within the fourth highest of ten categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (–) modifier after a rating indicates the relative standing within a particular rating category. S&P's Canadian commercial paper ratings scale ranges from A-1 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.

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 obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking 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.

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 2009.

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range			Share Volume	Share Price Trading Range			Share Volume
	High	**Low**	**Close**		**High**	**Low**	**Close**	
	(C$ per share)			*(millions)*	*($ per share)*			*(millions)*
2009								
January	63.50	51.55	54.57	52.7	53.81	40.95	44.34	79.6
February	58.65	44.64	50.20	52.6	48.04	35.70	39.37	94.9
March	55.71	45.67	51.60	68.2	45.28	35.46	40.61	98.1
April	57.75	50.33	54.69	49.3	47.84	39.70	45.73	64.3
May	65.71	54.72	60.00	46.8	57.07	46.02	55.43	62.3
June	63.35	53.85	57.67	44.4	58.34	46.58	49.47	56.5
July	59.68	51.34	57.78	36.6	54.89	44.01	53.65	50.4
August	58.92	54.65	57.06	33.9	55.74	49.23	51.99	36.2
September	64.29	54.96	62.00	46.2	59.95	49.71	57.61	59.6
October	65.34	59.00	60.00	37.3	63.19	54.18	55.39	58.0
November	62.90	55.11	56.57	46.4	59.68	51.91	53.88	53.4
December (1)								
Pre-Split	57.87	56.00	56.43	6.1	55.43	50.82	51.09	18.5
Post-Split	34.89	28.62	34.11	46.9	33.61	27.56	32.39	42.6

Note:

(1) The post-Split Common Shares began trading on the TSX for regular settlement at the opening of trading on December 3, 2009 and on the NYSE for regular settlement at the opening of trading on December 9, 2009.

In December 2009, EnCana received approval from the TSX to renew its Normal Course Issuer Bid ("NCIB"). Under the renewed program, EnCana is entitled to purchase up to 5 percent, approximately 37.5 million of its outstanding Common Shares as at November 30, 2009. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange.

During 2008, EnCana purchased approximately 4.8 million shares under the program at an average price of $67.13 for total consideration of approximately $326 million. On May 11, 2008, EnCana announced that it had suspended the purchases of Common Shares pending completion of the Split Transaction. EnCana did not purchase any Common Shares under its previous NCIB, which expired on November 12, 2009.

Dividends

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. During 2007, EnCana paid a quarterly dividend of $0.20 per share ($0.80 per share annually). From the first quarter of 2008 to the completion of the Split Transaction, EnCana paid a quarterly dividend of $0.40 per share ($1.60 per share annually). On December 31, 2009, after the Split Transaction, EnCana paid a quarterly dividend of $0.20 per share to Common Shareholders of record on December 21, 2009. The Board of Directors of Cenovus also declared a dividend of $0.20 per share payable on December 31, 2009 to Cenovus Common Shareholders of record on December 21, 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.

Risk Factors

If any event arising from the risk factors set forth below occurs, EnCana's business, prospects, financial condition, results of operations or cash flows and in some cases its reputation could be materially adversely affected.

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

EnCana's financial performance and condition are substantially dependent on the prevailing prices of natural gas and liquids. As EnCana is primarily a natural gas company, it is more significantly affected by changes in natural gas prices than changes in liquids prices. Fluctuations in natural gas and liquids prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its proved reserves. Prices for natural gas and liquids fluctuate in response to changes in the supply and demand for natural gas and crude oil, market uncertainty and a variety of additional factors beyond the Corporation's control.

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, coal, imported liquefied natural gas and renewable energy initiatives). Any substantial or extended decline in the price of 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.

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. NGLs prices are generally determined with reference to crude oil prices.

EnCana conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If natural gas and liquids 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, technology failures, accidents, the availability of skilled labour, and reservoir quality.

The tentative recovery from the global recession is creating ongoing fiscal challenges for the world economy. 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, including volatile changes in currency exchange rates, inflation, interest rates, and general levels of investing and consuming activity.

The Corporation undertakes a variety of projects including exploration and development projects and the construction or expansion of facilities and pipelines. Project delays may delay expected revenues and project cost overruns could make projects uneconomic.

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 natural gas and liquids 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 use, generation, handling, storage, transportation, treatment and disposal of chemicals, hazardous substances and waste associated with the finding, production, transmission and storage of the Corporation's products including the hydraulic fracturing of wells, the decommissioning of facilities 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 natural gas and crude oil 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 reserves, the Corporation's reserves and production will decline materially from their current levels.

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

There are numerous uncertainties inherent in estimating quantities of natural gas and liquids 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 natural gas and liquids 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 natural gas and liquids 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 natural gas and liquids prices and changes in interest rates. Under Canadian GAAP, derivative instruments that do not qualify as hedges for accounting purposes, or are not designated as hedges, are fair valued with the resulting changes 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 natural gas or liquids 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 natural gas and liquids and the operation of midstream facilities. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and liquid spills, acts of vandalism and terrorism, any of which could cause personal injury, result in damage to, or destruction of, natural gas and crude oil wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EnCana's operations will be subject to all of the risks normally incident to the transportation, processing, storing and marketing of natural gas, liquids, and other related products, drilling and completion of natural gas and crude oil wells, and the operation and development of natural gas and crude oil 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 natural gas, crude oil 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 natural gas and crude oil 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 ownership 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.

EnCana has certain indemnification obligations to Cenovus Energy Inc.

In relation to the Split Transaction, EnCana and Cenovus have each agreed to indemnify the other for certain liabilities and obligations associated with, among other things, in the case of EnCana's indemnity, the business and assets retained by EnCana, and in the case of Cenovus's indemnity, the business and assets transferred to Cenovus. EnCana cannot determine whether it will be required to indemnify Cenovus for any substantial obligations. EnCana also cannot be assured that, if Cenovus is required to indemnify EnCana and its affiliates for any substantial obligations, Cenovus will be able to satisfy such obligations. Any indemnification claim against EnCana pursuant to the provisions of the Split Transaction agreements could have a material adverse effect upon EnCana.

EnCana is exposed to counterparty risk.

EnCana is exposed to the risks associated with counterparty performance including credit risk and performance risk. EnCana may experience material financial losses in the event of customer payment default for commodity sales and financial derivative transactions. EnCana may be impacted by partner defaults with respect to the funding of partner obligations for capital projects. Performance risk can impact EnCana's operations by the non-delivery of contracted products or services by counterparties, which could impact on project timelines or operational efficiency.

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 may be located, from time to time, 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

In the United States:
BNY Mellon Shareholder Services
480 Washington Blvd.
Jersey City, NJ
07310

In order to respond to EnCana shareholder inquiries, the Corporation's transfer agent has set-up a dedicated answer line. Shareholder inquiries should be directed to the following:

Shareholders residing in Canada or the United States, please call 1-866-580-7145
Shareholders residing outside of North America, please call 1-416-643-5990

Shareholders can also send requests via the transfer agent's web site at www.cibcmellon.com/investorinquiry.

Interest of Experts

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 17, 2010 in respect of the Corporation's consolidated financial statements as at December 31, 2009 and December 31, 2008 and for each of the years in the three year period ended December 31, 2009 and the Corporation's internal control over financial reporting as at December 31, 2009. 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 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, 2009.

The Arrangement Agreement and Separation and Transition Agreement, described under "General Development of the Business – Split Transaction" are material contracts of EnCana and are available on SEDAR.

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: achieving its strategy to be a natural gas pure-play company focused on development of unconventional resources, drilling and development plans and the timing and location thereof, production and processing capacities and levels and the timing of achieving such capacities and levels, the anticipated date of production for the Deep Panuke natural gas project, expansion of gathering and processing plants and other facilities, reserves estimates, including reserves estimates under different price cases, 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: volatility of and assumptions regarding natural gas and liquids 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 natural gas and liquids 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 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 natural gas and liquids reserves, 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 processing facilities, risks associated with technology, EnCana’s ability to generate sufficient cash flow from operations to meet its current and future obligations, EnCana’s ability to access external sources of debt and equity capital, general economic and business conditions, EnCana’s ability to enter into or renew leases, the timing and costs of construction of gas storage facilities, wells and pipelines, EnCana’s ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, EnCana’s and its subsidiaries’ ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations, risks associated with existing and potential future lawsuits and regulatory actions against EnCana and its subsidiaries, political and economic conditions in the countries in which EnCana and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals and such other assumptions, risks and uncertainties described from time to time in EnCana’s reports and filings with the Canadian securities authorities and the U.S. 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. 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 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 using a historic constant price, whereas NI 51-101 requires disclosure of reserves and related future net revenue using forecast prices.

EnCana has disclosed proved reserves quantities using the standards contained in SEC Regulation S-K, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with FASB standards.

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.

Appendix A
Other Disclosures about Oil and Gas Activities

The tables in this Appendix set forth oil and gas information prepared by EnCana in accordance with FASB standards.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, constant price and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs 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 [1,2]			United States [1]		
($ millions)	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Future cash inflows	19,321	64,308	95,778	18,573	26,620	38,398
Less future:						
Production costs	6,296	23,017	25,089	4,862	6,079	5,869
Development costs	4,065	9,800	10,171	4,429	5,227	6,943
Asset retirement obligation payments	1,508	2,995	3,320	640	488	532
Income taxes	659	5,746	12,871	707	2,961	7,375
Future net cash flows	6,793	22,750	44,327	7,935	11,865	17,679
Less 10% annual discount for estimated timing of cash flows	2,704	10,036	21,663	3,592	5,218	8,196
Discounted future net cash flows	4,089	12,714	22,664	4,343	6,647	9,483

	Total [1]		
($ millions)	**2009**	**2008**	**2007**
Future cash inflows	37,894	90,928	134,176
Less future:			
Production costs	11,158	29,096	30,958
Development costs	8,494	15,027	17,114
Asset retirement obligation payments	2,148	3,483	3,852
Income taxes	1,366	8,707	20,246
Future net cash flows	14,728	34,615	62,006
Less 10% annual discount for estimated timing of cash flows	6,296	15,254	29,859
Discounted future net cash flows	8,432	19,361	32,147

Notes:

(1) 2009 future net cash flows have been calculated using 12-month average prices of: natural gas – AECO C$3.77/MMbtu and Henry Hub $3.87/MMbtu; crude oil – WTI $61.18/bbl and Edmonton Light C$65.64/bbl. Future net cash flows would have been $18,453 million (Canada - $8,508 million; United States - $9,945) using the following single day December 31, 2009 prices: natural gas – AECO C$5.63/MMbtu and Henry Hub $5.78/MMbtu; crude oil – WTI $79.36/bbl and Edmonton Light C$82.69/bbl. In 2008 and 2007, future net cash flows were calculated using the year-end price for the respective years.

(2) 2008 and 2007 estimates of future net cash flows included the cash flows from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These operations were transferred to Cenovus as part of the Split Transaction.

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

	Canada (1)			United States		
($ millions)	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Balance, beginning of year	12,714	22,664	16,596	6,647	9,483	6,454
Changes resulting from:						
Sales of oil and gas produced during the period	(5,609)	(7,346)	(6,055)	(3,442)	(4,125)	(3,281)
Discoveries and extensions, net of related costs	1,294	2,031	3,632	629	904	1,591
Purchases of proved reserves in place	16	58	120	-	14	372
Sales and transfers of proved reserves in place	(6,492)	(321)	(1,283)	(62)	(197)	(15)
Net change in prices and production costs	(1,825)	(14,632)	9,671	(1,446)	(4,204)	4,818
Revisions to quantity estimates	(1,242)	1,736	603	(1,567)	667	830
Accretion of discount	1,572	2,905	2,087	827	1,346	924
Previously estimated development costs incurred net of change in future development costs	737	1,923	(259)	1,474	315	(907)
Other	150	321	(341)	(26)	88	(113)
Net change in income taxes	2,774	3,375	(2,107)	1,309	2,356	(1,190)
Balance, end of year	4,089	12,714	22,664	4,343	6,647	9,483

	Total		
($ millions)	**2009**	**2008**	**2007**
Balance, beginning of year	19,361	32,147	23,050
Changes resulting from:			
Sales of oil and gas produced during the period	(9,051)	(11,471)	(9,336)
Discoveries and extensions, net of related costs	1,923	2,935	5,223
Purchases of proved reserves in place	16	72	492
Sales and transfers of proved reserves in place	(6,554)	(518)	(1,298)
Net change in prices and production costs	(3,271)	(18,836)	14,489
Revisions to quantity estimates	(2,809)	2,403	1,433
Accretion of discount	2,399	4,251	3,011
Previously estimated development costs incurred net of change in future development costs	2,211	2,238	(1,166)
Other	124	409	(454)
Net change in income taxes	4,083	5,731	(3,297)
Balance, end of year	8,432	19,361	32,147

Note:

(1) Results prior to November 30, 2009 include reserves from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Results of Operations

($ millions)	Canada (1) 2009	Canada (1) 2008	Canada (1) 2007	United States 2009	United States 2008	United States 2007
Oil and gas revenues, net of royalties, transportation and selling costs	6,835	8,848	7,361	4,007	5,127	4,065
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,226	1,502	1,306	565	1,002	784
Depreciation, depletion and amortization	1,980	2,198	2,298	1,561	1,691	1,181
Operating income (loss)	3,629	5,148	3,757	1,881	2,434	2,100
Income taxes	1,059	1,502	1,114	698	937	809
Results of operations	2,570	3,646	2,643	1,183	1,497	1,291

($ millions)	Other 2009	Other 2008	Other 2007	Total 2009	Total 2008	Total 2007
Oil and gas revenues, net of royalties, transportation and selling costs	-	2	-	10,842	13,977	11,426
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	-	(2)	19	1,791	2,502	2,109
Depreciation, depletion and amortization	28	39	69	3,569	3,928	3,548
Operating income (loss)	(28)	(35)	(88)	5,482	7,547	5,769
Income taxes	-	-	-	1,757	2,439	1,923
Results of operations	(28)	(35)	(88)	3,725	5,108	3,846

Note:

(1) Results of Operations prior to November 30, 2009 include Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Capitalized Costs

($ millions)	Canada (1) 2009	Canada (1) 2008	Canada (1) 2007	United States 2009	United States 2008	United States 2007
Proved oil and gas properties	21,459	33,466	37,120	19,843	15,755	13,773
Unproved oil and gas properties	728	870	1,380	1,178	3,399	1,852
Total capital cost	22,187	34,336	38,500	21,021	19,154	15,625
Accumulated DD&A	11,586	17,348	19,286	7,092	5,511	3,783
Net capitalized costs	10,601	16,988	19,214	13,929	13,643	11,842

($ millions)	Other 2009	Other 2008	Other 2007	Total 2009	Total 2008	Total 2007
Proved oil and gas properties	-	-	-	41,302	49,221	50,893
Unproved oil and gas properties	157	122	305	2,063	4,391	3,537
Total capital cost	157	122	305	43,365	53,612	54,430
Accumulated DD&A	147	112	160	18,825	22,971	23,229
Net capitalized costs	10	10	145	24,540	30,641	31,201

Note:

(1) Results prior to November 30, 2009 include capitalized costs from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Costs Incurred

	Canada (1)			United States		
($ millions)	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Acquisitions						
Unproved	46	32	28	46	1,006	1,048
Proved	178	119	61	-	17	1,565
Total acquisitions	224	151	89	46	1,023	2,613
Exploration costs	129	474	427	133	197	48
Development costs	2,588	3,485	3,214	1,688	2,485	1,887
Total costs incurred	2,941	4,110	3,730	1,867	3,705	4,548

	Other			Total		
($ millions)	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Acquisitions						
Unproved	-	-	-	92	1,038	1,076
Proved	-	-	-	178	136	1,626
Total acquisitions	-	-	-	270	1,174	2,702
Exploration costs	2	14	60	264	685	535
Development costs	-	-	-	4,276	5,970	5,101
Total costs incurred	2	14	60	4,810	7,829	8,338

Note:

(1) Results prior to November 30, 2009 include costs incurred from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Appendix B
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, 2009. The reserves data consists of the following:

   (a) estimated proved oil and gas reserves quantities as at December 31, 2009 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, 2009:

		Estimated Proved Reserves Quantities After Royalty		**Related Estimates of Future Net Cash Flow Before Tax, 10% discount rate**
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	
		(Bcf)	*(MMbbl)*	*(US$MM)*
McDaniel & Associates Consultants Ltd. January 11, 2010	Canada	1,351	9	1,156
GLJ Petroleum Consultants Ltd. January 12, 2010	Canada	3,998	27	3,018
Netherland, Sewell & Associates, Inc. January 11, 2010	United States	3,639	38	3,529
DeGolyer and MacNaughton January 20, 2010	United States	2,074	3	1,022
Totals		11,062	77	8,725

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 9, 2010

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

(a) proved oil and gas reserves quantities estimated as at December 31, 2009 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 9, 2010 (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 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) Robert A. Grant
Executive Vice-President,
Corporate Development, EH&S and Reserves

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

(signed) Claire S. Farley
Director and Chair of the Reserves Committee

February 10, 2010

Appendix D
Audit Committee Mandate

Last updated December 8, 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 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 three and not more than five 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 Corporation'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. See Quorum for further details.

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 Executive Vice-President & Chief Accounting Officer and the Vice-President, Financial Compliance & 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 management's processes in place to prevent and detect fraud.

16. 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.

17. 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.

18. Meet on a periodic basis separately with management.

External Auditors

19. 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.

20. 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.

21. 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.

22. 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.

23. 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.

24. Review and evaluate:

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

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

c. External audit plans and results.

d. Any other related audit engagement matters.

e. The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

25. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 21 through 24, 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.

26. 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.

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

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

29. 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 Independence

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

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

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

Approval of Audit and Non-Audit Services

33. 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).

34. 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.

35. If the pre-approvals contemplated in paragraphs 33 and 34 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.

36. 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 33 through 35. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

37. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 33 and 34, 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

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

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

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

41. 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.

42. 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.

43. 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.

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

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

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

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