Encana Corporation

Annual Information Form
February 23, 2012

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Introduction

This is the annual information form of **Encana Corporation** ("Encana" or the "Company") for the year ended December 31, 2011. In this annual information form, unless otherwise specified or the context otherwise requires, reference to "Encana" or to the "Company" includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

In this annual information form, daily natural gas volumes are referenced in either thousands of cubic feet ("Mcf") per day ("Mcf/d"), millions of cubic feet ("MMcf") per day ("MMcf/d"), or billions of cubic feet ("Bcf") per day ("Bcf/d"). The term "liquids" is used to represent oil, natural gas liquids ("NGLs") and condensate. Daily liquids volumes are referenced in either barrels ("bbls") per day ("bbls/d"), thousands of barrels ("Mbbls") per day ("Mbbls/d") or millions of barrels ("MMbbls") per day ("MMbbls/d").

Certain liquids volumes have been converted to thousands of cubic feet equivalent ("Mcfe"), millions of cubic feet equivalent ("MMcfe") or billions of cubic feet equivalent ("Bcfe") on the basis of one barrel ("bbl") to six Mcf. Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the same basis. Mcfe, MMcfe, Bcfe and BOE may be misleading, particularly if used in isolation. An Mcfe, MMcfe or Bcfe 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 wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

On January 1, 2011, Encana adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using a transition date of January 1, 2010. The Company's annual audited Consolidated Financial Statements for the year ended December 31, 2011, including 2010 required comparative information, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board ("IASB"). Prior to 2011, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP").

Unless otherwise indicated, all financial information included in this annual information form is determined using IFRS, which differ from U.S. generally accepted accounting principles ("U.S. GAAP"). Note 27 to Encana's annual audited Consolidated Financial Statements for the year ended December 31, 2011 contains a discussion of the principal differences between Encana's financial results calculated under IFRS and 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".

Unless otherwise specified, all dollar amounts are expressed in United States ("U.S.") dollars, all references to "dollars", "$" or to "US$" are to U.S. dollars and all references to "C$" are to Canadian dollars. All proceeds from divestitures are provided on a before-tax basis.

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.

On November 30, 2009, Encana completed a corporate reorganization (the "Split Transaction") to split into two independent publicly traded energy companies – Encana and Cenovus Energy Inc. ("Cenovus"). In conjunction with the Split Transaction, Encana's articles were amended to make certain changes to its share capital. Further information on the Company'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, 2011. Each of these subsidiaries and partnerships had total assets that exceeded 10 percent of Encana's total consolidated assets or annual revenues that exceeded 10 percent of Encana's total consolidated annual revenues as at December 31, 2011.

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 Encana's total consolidated assets or total consolidated annual revenues as at December 31, 2011.

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"). On November 30, 2009, Encana completed the Split Transaction which resulted in two independent publicly traded energy companies – Encana and Cenovus.

Encana is a leading North American energy producer that is focused on growing its strong portfolio of diverse resource plays producing natural gas, oil and NGLs. Encana's other operations include the transportation and marketing of natural gas, oil and NGLs. All of Encana's reserves and production are located in North America.

Operating Divisions

Encana employs a decentralized decision making structure and is currently divided into two operating divisions. The operating divisions are:

- **Canadian Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within Canada. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia, including Horn River; (ii) Cutbank Ridge in Alberta and British Columbia, including Montney; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in southern Alberta. The Canadian Division also includes the Deep Panuke natural gas project offshore Nova Scotia.

- **USA Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) Haynesville in Louisiana; and (iv) Texas, including East Texas and North Texas.

Encana's proprietary production is substantially sold by the Midstream, Marketing & Fundamentals team, which is focused on enhancing the Company'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.

Encana's Natural Gas Economy team focuses on pursuing the development of expanded natural gas markets in North America, particularly within the areas of power generation, transportation and industrial applications. Due to the technical breakthroughs which have enhanced 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 greenhouse gas and volatile organic compound emissions as compared to other fossil fuel use.

For 2011 financial reporting purposes, Encana's reportable segments were: (i) Canada; (ii) USA; (iii) Market Optimization; and (iv) Corporate and Other. Corporate and Other is not an operating segment and mainly includes unrealized gains or losses recognized on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recognized in the operating segment to which the derivative instruments relate.

Recent Developments

Significant events which contributed to the development of Encana's business over the last three years included the following:

2011

- Acquired various strategic exploration and evaluation lands and properties which complement existing assets within Encana's portfolio, totaling $515 million. Land capture included additional acreage with potential oil and natural gas streams with associated liquids.

- Completed planned divestitures for total proceeds of $891 million of Encana's interest in the Cabin natural gas processing plant in British Columbia, the Fort Lupton natural gas processing plant in Colorado and the South Piceance natural gas gathering assets in Colorado.

- Closed the majority of the sale of its North Texas natural gas producing assets for proceeds of $836 million. On February 7, 2012, Encana received additional proceeds of $91 million. The remainder of the sale, for proceeds of approximately $24 million, is subject to completion of additional closing conditions and is expected to close in the first quarter of 2012.

- Agreed to sell two natural gas processing plants in the Cutbank Ridge area of British Columbia for approximately C$920 million. The sale closed on February 9, 2012 and the proceeds were received.

- Entered into negotiations with Mitsubishi Corporation ("Mitsubishi") to jointly develop certain undeveloped lands owned by Encana. On February 17, 2012, Encana announced that the Company and Mitsubishi had entered into a partnership agreement for the development of Cutbank Ridge lands in British Columbia. Under the agreement, Mitsubishi will invest approximately C$2.9 billion for a 40 percent interest in the partnership. The transaction is expected to close by the end of February 2012.

- Entered into deep cut processing arrangements, which will allow the Company to extract additional NGL volumes from its natural gas streams starting in 2012 at the Musreau and Gordondale plants in the Alberta Deep Basin.

- Acquired a 30 percent interest in the planned Kitimat liquefied natural gas ("LNG") export terminal in British Columbia.

- Entered into an agreement to be the sole LNG fueling supplier to a fleet of 200 LNG heavy-duty trucks in Louisiana through its mobile and permanent LNG fueling stations and opened four compressed natural gas fueling stations.

- Ended negotiations with PetroChina International Investment Company, a subsidiary of PetroChina Company Limited ("PetroChina"), for a proposed joint venture concerning a 50 percent interest in Encana's Cutbank Ridge business assets after the parties were unable to achieve substantial alignment with respect to key elements of the proposed transaction. Negotiations with PetroChina commenced in 2010.

2010

- Entered into farm-out agreements with Kogas Canada Ltd., a subsidiary of Korea Gas Corporation ("Kogas"), which agreed to invest approximately C$565 million over three years to earn a 50 percent interest in approximately 154,000 acres of land in Horn River and Montney in the Greater Sierra and Cutbank Ridge key resource plays. In 2011, Encana extended a farm-out agreement with Kogas for an additional investment of C$185 million for approximately 20,000 additional acres.

- Acquired various strategic lands and properties that complement existing assets within Encana's portfolio. In 2010, acquisitions were $592 million in the Canadian Division and $141 million in the USA Division.

- Completed the divestiture of non-core assets for proceeds of approximately $288 million in the Canadian Division and $595 million in the USA Division.

2009

- Completed the Split Transaction on November 30, 2009, resulting in Encana and Cenovus. 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. 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.

  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.

- 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 related to the Canadian upstream assets transferred to Cenovus.

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, 2011.

Encana's operations are focused on exploiting North American long-life natural gas and oil formations. Encana attempts to identify early-stage, geographically expansive hydrocarbon-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, oil, and NGLs 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 applied across Encana's expansive portfolio.

Encana's operations are primarily located in Canada and the U.S. All of Encana's reserves and production are located in North America.

Canadian Division

The Canadian Division includes the exploration for, development of, and production of, natural gas, oil and NGLs and other related activities within Canada. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia, including Horn River; (ii) Cutbank Ridge in Alberta and British Columbia, including Montney; (iii) Bighorn in west central Alberta; and (iv) CBM in southern Alberta. The Canadian Division also includes the Deep Panuke natural gas project offshore Nova Scotia.

In 2011, the Canadian Division had total capital investment in Canada of approximately $2,022 million and drilled approximately 727 net wells. As at December 31, 2011, the Canadian Division had an established land position in Canada of approximately 10.1 million gross acres (8.5 million net acres), including approximately 5.2 million gross undeveloped acres (4.4 million net acres). The mineral rights on approximately 42 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 2011 natural gas production after royalties averaged approximately 1,454 MMcf/d, an increase over 2010 of approximately 131 MMcf/d, or 10 percent. Oil and NGL production after royalties averaged approximately 14.5 Mbbls/d for 2011, an increase over 2010 of approximately 1.3 Mbbls/d, or 10 percent. The increase in natural gas, oil and NGL production was primarily due to successful drilling programs across all key resource plays.

The following tables summarize the Canadian Division landholdings, producing wells and daily production as at and for the periods indicated. In 2011, Encana realigned the producing assets contained in some of its key resource plays.

Landholdings

(thousands of acres at December 31, 2011)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Greater Sierra	557	511	1,264	1,041	1,821	1,552	85%
Cutbank Ridge	446	358	911	793	1,357	1,151	85%
Bighorn	257	179	257	205	514	384	75%
CBM	3,403	2,931	1,820	1,661	5,223	4,592	88%
Key Resource Plays	4,663	3,979	4,252	3,700	8,915	7,679	86%
Atlantic Canada	20	20	56	12	76	32	42%
Other	186	86	899	708	1,085	794	73%
Total Canadian Division	**4,869**	**4,085**	**5,207**	**4,420**	**10,076**	**8,505**	**84%**

Producing Wells

(number of wells at December 31, 2011) (1)	Natural Gas		Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Greater Sierra	973	907	-	-	973	907
Cutbank Ridge	996	845	20	6	1,016	851
Bighorn	459	366	28	8	487	374
CBM	11,425	10,448	183	147	11,608	10,595
Key Resource Plays	13,853	12,566	231	161	14,084	12,727
Other	19	12	2	1	21	13
Total Canadian Division	**13,872**	**12,578**	**233**	**162**	**14,105**	**12,740**

Notes:
(1) Figures exclude wells capable of producing, but not producing.

Production (Before Royalties)

(average daily)	Natural Gas *(MMcf/d)*		Oil & NGLs *(Mbbls/d)*	
	2011	**2010**	**2011**	**2010**
Greater Sierra	275	239	1.1	1.2
Cutbank Ridge	571	486	3.9	2.7
Bighorn	233	226	4.5	4.4
CBM	440	401	7.0	6.1
Key Resource Plays (1)	1,519	1,352	16.5	14.4
Other	2	29	-	1.3
Total Canadian Division	**1,521**	**1,381**	**16.5**	**15.7**

Note:
(1) Key resource play areas were realigned in 2011, with comparative information restated.

Production (After Royalties)

(average daily)	Natural Gas (MMcf/d) 2011	Natural Gas (MMcf/d) 2010	Oil & NGLs (Mbbls/d) 2011	Oil & NGLs (Mbbls/d) 2010
Greater Sierra	260	230	0.8	1.0
Cutbank Ridge	529	449	3.2	2.0
Bighorn	230	220	3.5	3.2
CBM	433	395	7.0	6.0
Key Resource Plays (1)	1,452	1,294	14.5	12.2
Other	2	29	-	1.0
Total Canadian Division	**1,454**	**1,323**	**14.5**	**13.2**

Note:
(1) Key resource play areas were realigned in 2011, with comparative information restated.

Key Resource Plays and Activities in the Canadian Division

Greater Sierra

Greater Sierra 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 2011, Encana drilled approximately 34 net wells in the area and production after royalties averaged approximately 260 MMcf/d of natural gas and approximately 0.8 Mbbls/d of oil and NGLs.

At December 31, 2011, Encana controlled approximately 373,000 gross undeveloped acres (272,000 net acres) in the Devonian shale formation of Horn River in northeast British Columbia. Horn River formation shales (Muskwa, Otter Park and Evie) within Encana's focus area are upwards of 500 feet thick. At December 31, 2011, these shales have been evaluated with approximately 112 gross wells (11 vertical and 101 horizontal), 70 of which have been placed on long-term production (1 vertical and 69 horizontal). At December 31, 2011, Encana held an average 76 percent working interest in 10 production facilities in the area that were capable of processing approximately 726 MMcf/d of natural gas.

In November 2011, Encana sold its working interest in the Ekwan pipeline to TransCanada Pipelines Limited ("TCPL") following the National Energy Board's approval of TCPL's pipeline in the Horn River area. TCPL's pipeline will interconnect the Horn River area to its Alberta pipeline system. As part of the transfer agreement with TCPL, Encana will continue to have gathering capacity on the Ekwan pipeline.

In December 2011, Encana completed the sale of the majority of its interest in the Cabin natural gas processing plant in the Horn River area for proceeds of approximately $48 million, net of amounts recovered for capital expenditures incurred prior to the sale of the plant. Encana remains the operator of the Cabin plant. As part of the sale agreement, Encana will have processing capacity at the Cabin plant.

Cutbank Ridge

Cutbank Ridge 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. Montney and Cadomin 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 2011, Encana drilled approximately 55 net wells in the area and production after royalties averaged approximately 529 MMcf/d of natural gas and approximately 3.2 Mbbls/d of oil and NGLs.

At December 31, 2011, Encana controlled approximately 724,000 net acres covering the deep basin Montney formation, with approximately 252,000 net acres located within Encana's core development area near Dawson Creek, British Columbia. Encana has tested Montney extensively over the last several years and by applying advanced technology has reduced overall development costs significantly, achieving a greater than 65 percent reduction in costs on a completed interval basis over the past five years.

Encana holds a 60 percent working interest in the Sexsmith gas plant, which has sour gas processing capacity of approximately 125 MMcf/d and an additional 50 MMcf/d of sweet gas processing capacity.

In December 2011, Encana announced the sale of its interest in the Hythe and Steeprock natural gas processing plants, including compression and associated gathering pipelines, for proceeds of approximately C$920 million. The natural gas plants had sour gas processing capacity of approximately 374 MMcf/d with an additional 142 MMcf/d of sweet gas processing capacity. The sale of the natural gas processing plants closed on February 9, 2012 and the proceeds were received. As part of the sale, Encana has entered into an agreement for firm gathering and processing services in the Cutbank Ridge area.

During 2011, Encana entered into negotiations with Mitsubishi to jointly develop certain undeveloped lands owned by Encana. On February 17, 2012, Encana announced that the Company and Mitsubishi had entered into a partnership agreement for the development of Cutbank Ridge lands in British Columbia. Under the agreement, Encana will own 60 percent and Mitsubishi will own 40 percent of the partnership. Mitsubishi will pay approximately C$1.45 billion on closing and will invest approximately C$1.45 billion in addition to its 40 percent of the partnership's future capital investment for a commitment period, which is expected to be about five years, thereby reducing Encana's capital funding commitments to 30 percent of the total expected capital investment over that period. The transaction does not include any of Encana's current Cutbank Ridge production, processing plants, gathering systems or the Company's Alberta landholdings. The transaction is expected to close by the end of February 2012.

In 2010, Encana signed a deep cut processing agreement securing approximately 90 MMcf/d of firm processing capacity at Gordondale. The agreement allows the Company to extract NGLs from its natural gas stream. The addition of deep cut facilities in Gordondale, expected to come on-stream in 2012, will provide additional capacity for Encana's NGL extraction initiative.

Bighorn

Bighorn is a key resource play in west central Alberta. The primary focus is on exploiting multi-zone stacked Cretaceous sands in the Deep Basin. The primary properties in Bighorn are Resthaven, Kakwa, Redrock and Berland. In 2011, Encana drilled approximately 40 net wells in the area and production after royalties averaged approximately 230 MMcf/d of natural gas and approximately 3.5 Mbbls/d of oil and NGLs. At December 31, 2011, Encana controlled approximately 514,000 gross acres (384,000 net acres) in the resource play.

Encana has a working interest in a number of natural gas plants within Bighorn. The Resthaven plant, in which Encana has an approximately 70 percent working interest, has a capacity of approximately 100 MMcf/d. In October 2011, Encana signed an agreement that is expected to result in an unrelated third-party investing approximately $230 million to expand the Resthaven plant's processing and NGL extraction capacity. The expansion is scheduled to come on-stream in late 2013.

Encana owns 50 percent of the Kakwa gas plant and has firm processing capacity for the remaining 50 percent. The plant has a capacity of approximately 60 MMcf/d. Encana also holds a 24 percent working interest in the Berland River plant, which has a capacity of approximately 165 MMcf/d.

In 2010, Encana signed a deep cut processing agreement securing approximately 144 MMcf/d of firm processing capacity at Musreau. The agreement allows the Company to extract NGLs from its natural gas stream. In 2011, Encana expanded its deep cut facilities at Musreau, which are expected to come on-stream in the first quarter of 2012.

CBM

CBM is a key resource play that extends from the U.S. border to central Alberta. The primary focus of Encana's CBM key resource play is the development of the Horseshoe Canyon coals integrated with shallower sands, as well as exploiting deeper targets using an integrated wellbore strategy. Additionally, multiple oil horizons are also being tested on fee title lands through farm-outs with third parties. In 2011, Encana drilled approximately 596 net wells in the area and production after royalties averaged approximately 433 MMcf/d of natural gas and 7.0 Mbbls/d of oil and NGLs.

At December 31, 2011, Encana controlled approximately 4.6 million net acres with approximately 2.1 million net acres on the Horseshoe Canyon trend. Approximately 77 percent of the total net acreage landholdings are owned in fee title.

Atlantic Canada

Encana is the owner and operator of the Deep Panuke gas field, located offshore Nova Scotia. 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 in mid-2012.

At December 31, 2011, 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 six of its nine licenses in these areas and has an average working interest of approximately 42 percent.

Other

At December 31, 2011, Encana held an interest in approximately 513,000 gross acres (373,000 net acres) in the Duvernay Shale play in Alberta, consisting of potential natural gas streams with associated liquids. In 2012, the Company plans to drill five net evaluation wells in the area.

USA Division

The USA Division includes the exploration for, development of, and production of, natural gas, oil and NGLs and other related activities within the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) Haynesville in Louisiana; and (iv) Texas, including East Texas and North Texas.

In 2011, the USA Division had total capital investment of approximately $2,423 million and drilled approximately 402 net wells. As at December 31, 2011, the USA Division had an established land position of approximately 2.8 million gross acres (2.4 million net acres), including approximately 2.2 million gross undeveloped acres (1.9 million net acres).

The USA Division's 2011 natural gas production after royalties averaged approximately 1,879 MMcf/d, an increase over 2010 of approximately 18 MMcf/d. The increase was due to operational success in Haynesville, partially offset by net divestitures and natural declines. The USA Division's 2011 oil and NGL production after royalties averaged approximately 9.5 Mbbls/d, consistent with 2010 volumes.

The following tables summarize the USA Division landholdings, producing wells and daily production as at and for the periods indicated. In 2011, Encana realigned the producing assets contained in some of its key resource plays.

Landholdings

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
(thousands of acres at December 31, 2011)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Jonah	19	19	117	104	136	123	90%
Piceance	258	240	638	589	896	829	92%
Texas	109	73	238	171	347	244	70%
Haynesville	154	88	201	121	355	209	59%
Key Resource Plays	540	420	1,194	985	1,734	1,405	81%
Other	106	82	980	932	1,086	1,014	93%
Total USA Division	**646**	**502**	**2,174**	**1,917**	**2,820**	**2,419**	**86%**

Producing Wells

	Natural Gas		Oil		Total	
(number of wells at December 31, 2011) (1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Jonah	1,371	1,194	-	-	1,371	1,194
Piceance	3,602	3,056	3	-	3,605	3,056
Texas	774	494	-	-	774	494
Haynesville	409	216	-	-	409	216
Key Resource Plays	6,156	4,960	3	-	6,159	4,960
Other	1,660	1,123	5	3	1,665	1,126
Total USA Division	**7,816**	**6,083**	**8**	**3**	**7,824**	**6,086**

Notes:
(1) Figures exclude wells capable of producing, but not producing.

Production (Before Royalties)

	Natural Gas *(MMcf/d)*		Oil & NGLs *(Mbbls/d)*	
(average daily)	**2011**	**2010**	**2011**	**2010**
Jonah	602	674	5.5	5.9
Piceance	507	521	2.2	2.2
Texas	499	655	0.4	0.3
Haynesville	635	357	-	-
Key Resource Plays (1)	2,243	2,207	8.1	8.4
Other	109	135	3.6	3.5
Total USA Division	**2,352**	**2,342**	**11.7**	**11.9**

Note:
(1) Key resource play areas were realigned in 2011, with comparative information restated.

Production (After Royalties)

(average daily)	Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)	
	2011	**2010**	**2011**	**2010**
Jonah	471	531	4.3	4.6
Piceance	435	446	1.9	2.0
Texas	376	487	0.3	0.2
Haynesville	508	287	-	-
Key Resource Plays (1)	1,790	1,751	6.5	6.8
Other	89	110	3.0	2.8
Total USA Division	**1,879**	**1,861**	**9.5**	**9.6**

Note:
(1) Key resource play areas were realigned in 2011, with comparative information restated.

Key Resource Plays and Activities in the USA Division

Jonah

Jonah 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. In 2011, Encana drilled approximately 71 net wells within the core area and production after royalties averaged approximately 471 MMcf/d of natural gas and approximately 4.3 Mbbls/d of oil and NGLs.

In 2011, Encana finalized a joint venture agreement under which Encana has drilled approximately 19 net wells utilizing third-party funds. For the period of 2012 to 2015, Encana expects to drill approximately 59 net wells, which will be partially funded by third parties under existing agreements.

At December 31, 2011, Encana controlled approximately 117,000 gross undeveloped acres (104,000 net acres). Historically, Encana's operations have been conducted in the over-pressured core portion of the field. Development in the adjacent normally pressured lands began in 2008 and has continued through 2011. 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 114,000 gross undeveloped acres, where 40 acre and possibly 20 acre drilling potential exists.

Piceance

Piceance is a key resource play located in northwest Colorado. The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. In addition to Williams Fork, Encana has begun exploration drilling in the Niobrara formation, a thick shale predominant throughout the basin. In 2011, Encana drilled approximately 141 net wells and production after royalties averaged approximately 435 MMcf/d of natural gas and approximately 1.9 Mbbls/d of oil and NGLs. At December 31, 2011, Encana controlled approximately 638,000 gross undeveloped acres (589,000 net acres).

Between 2006 and 2011, Encana finalized 11 agreements to jointly develop portions of Piceance. During 2011, Encana drilled approximately 120 net wells primarily utilizing third-party funds. For the period of 2012 to 2017, it is expected that Encana will drill approximately 703 net wells which will be partially funded by third parties under existing agreements.

During 2011, Encana completed the sale of the South Piceance natural gas gathering assets for proceeds of approximately $547 million. Under the sale agreement, Encana will continue to have access to gathering services. The Company's remaining compression and processing facilities in Piceance include approximately 1,444 kilometres of pipelines and a processing facility with a capacity of approximately 60 MMcf/d. In addition, Encana has access to third-party processing facilities within Piceance.

Texas

Texas is a key resource play with current operations primarily located in East Texas. Operations in East Texas are characterized as a gas play containing tight gas with multi-zone targets in the Bossier and Cotton Valley zones, as well as shale gas in the Haynesville and Mid-Bossier horizons.

In December 2011, Encana closed the majority of the sale of its North Texas natural gas producing assets from the Barnett shale in the Forth Worth Basin for proceeds of $836 million. On February 7, 2012, Encana received additional proceeds of $91 million. The remainder of the sale, for proceeds of approximately $24 million, is subject to completion of additional closing conditions and is expected to close in the first quarter of 2012.

In 2011, Encana drilled approximately 41 net wells in Texas and production after royalties averaged approximately 376 MMcf/d of natural gas and approximately 0.3 Mbbls/d of oil and NGLs. In 2011, production after royalties for the North Texas producing assets disposed of totaled approximately 90 MMcf/d of natural gas and approximately 0.2 Mbbls/d of oil and NGLs. At December 31, 2011, Encana controlled approximately 238,000 gross undeveloped acres (171,000 net acres).

Haynesville

The Haynesville shale is a key resource play located in Louisiana. Encana drilled its first wells in 2006 and has continued to develop the lands using a multi-well pad approach in key areas. Encana has entered into joint venture agreements with unrelated third parties to explore and develop the assets in this area.

In 2011, Encana drilled approximately 87 net wells in the area and production after royalties averaged approximately 508 MMcf/d of natural gas. The majority of the development activity in the area focuses on the maximization of gas recovery in Haynesville and Mid-Bossier horizons.

At December 31, 2011, Encana controlled approximately 201,000 gross undeveloped acres (121,000 net acres), with the majority of the leaseholds in North Louisiana being located in the DeSoto and Red River parishes. Certain Haynesville undeveloped acreage is subject to leases that will expire over the next several years unless production is established on the acreage held.

Other Activity

Encana has established a significant land position in the Collingwood/Utica shale play located in Michigan. At December 31, 2011, Encana controlled approximately 430,000 net undeveloped acres. Encana successfully drilled and completed two net horizontal wells in 2011, with an effective horizontal length ranging between 5,300 feet and 7,500 feet.

In 2011, Encana established a significant land position in the Tuscaloosa Marine Shale oil play located in Louisiana and Mississippi, and holds approximately 212,000 net acres in this play as at December 31, 2011. Encana successfully completed two horizontal wells, with effective horizontal lengths of approximately 5,000 feet and 7,500 feet, respectively. In 2012, the Company plans to drill six gross evaluation wells in the area.

Encana holds approximately 48,000 net acres in the DJ Basin located in Northern Colorado. The primary formation targets in the basin are the Codell, J-Sand and the Niobrara, the latter consisting of potential natural gas streams with associated liquids. In 2011, Encana successfully drilled and completed five horizontal wells in the Niobrara to test the economic feasibility of the formation. Additional wells are planned for 2012 to help define lateral orientation and length. In 2012, the Company plans to drill 10 gross evaluation wells in the area.

Market Optimization

Market Optimization activities are managed by Encana's Midstream, Marketing & Fundamentals team, which is responsible for the sale of, and is focused on enhancing the netback price of, the Company'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 regional supply and demand for natural gas and by competing fuels in such markets.

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 22 to Encana's audited Consolidated Financial Statements for the year ended December 31, 2011 which are available via the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com and the Electronic Data Gathering, Analysis and Retrieval System ("EDGAR") at www.sec.gov.

Other Marketing Activities

Encana sells its oil, NGLs and condensate 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.

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 majority of Encana's production is sold under short term contracts at the relevant market price at the time that the product is sold. As at December 31, 2011, Encana had no material long term physical sales contracts or delivery contracts.

Former Operations

Former operations include the Canadian upstream assets and the U.S. downstream refining assets that were transferred to Cenovus as part of the Split Transaction on November 30, 2009.

The Canadian upstream assets transferred to Cenovus included established natural gas development and production activities in southern Alberta and southern Saskatchewan, 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. The five key resource plays included in these assets were: (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 an integrated oil business with ConocoPhillips.

During 2009 and prior to the Split Transaction, Encana drilled approximately 639 net wells on the Canadian upstream properties transferred to Cenovus. Natural gas production after royalties was approximately 762 MMcf/d and oil and NGL production after royalties was approximately 99.9 Mbbls/d.

The U.S. downstream refining assets transferred to Cenovus focused on the refining of 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 part of an integrated oil business with ConocoPhillips. The refineries were 50 percent owned by Encana and operated by ConocoPhillips.

In 2009, under previous GAAP, the Canadian upstream assets transferred to Cenovus were reported as continuing operations under full cost accounting, while the U.S. downstream refining results were reported as discontinued operations.

Reserves and Other Oil and Gas Information

Encana is required to provide reserves data prepared in accordance with Canadian securities regulatory requirements, specifically National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Certain reserves and oil and gas information in accordance with Canadian disclosure requirements are contained in ***Appendix A – Canadian Protocol Disclosure of Reserves Data and Other Oil and Gas Information.*** Additional disclosure required by NI 51-101 is included in the preceding sections of this annual information form, and referenced accordingly herein. Select supplemental reserves and other oil and gas information disclosure is provided in accordance with U.S. disclosure requirements in ***Appendix D – U.S. Protocol Disclosure of Reserves Data and Other Oil and Gas Information***. See "Note Regarding Reserves Data and Other Oil and Gas Information".

The practice of preparing production and reserve quantities data under Canadian disclosure requirements (NI 51-101) differs from the U.S. reporting requirements. The primary differences between the two reporting requirements include:

- the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves;
- the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average prices which are held constant;
- the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis;
- the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis; and
- the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards.

Since its formation in 2002, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of Encana's natural gas, oil and NGL reserves annually. In 2011, 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 six other staff under this individual's direction oversee the preparation of the reserves estimates by the IQREs. Currently this internal staff of four professional engineers, an engineering technologist and two business analysts have combined relevant experience of over 100 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. Annually, the Reserves Committee recommends the selection of IQREs to the Board of Directors for its approval.

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.

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 any of these sources.

The following table summarizes Encana's net capital investment for 2011 and 2010. Proceeds from divestitures that remain subject to additional closing conditions as at December 31, 2011 are not included.

($ millions)	**2011**	**2010**
Capital Investment		
Canadian Division	2,022	2,206
USA Division	2,423	2,495
	4,445	4,701
Market Optimization	2	2
Corporate & Other	131	61
	4,578	4,764
Acquisitions		
Property		
Canadian Division	410	592
USA Division	105	141
Divestitures		
Property		
Canadian Division	(350)	(288)
USA Division	(1,730)	(595)
Net Acquisitions and Divestitures	(1,565)	(150)
Net Capital Investment	**3,013**	**4,614**

Capital investment during 2011 was focused on continued development of Encana's key resource plays. Acquisitions primarily included the purchase of various strategic exploration and evaluation lands and properties that complement existing assets within Encana's portfolio.

Divestitures for 2011 in the Canadian Division included the proceeds from the sale of the Company's interest in the Cabin natural gas processing plant. Divestiture proceeds in the USA Division resulted primarily from the sale of the Company's interest in the Fort Lupton natural gas processing plant, the South Piceance natural gas gathering assets and the North Texas natural gas producing properties.

Competitive Conditions

All aspects of the oil and gas industry are highly competitive and Encana actively competes with upstream natural gas and other companies, particularly in the following areas:

- Exploration for and development of new sources of natural gas, oil and NGL reserves;
- Reserves and property acquisitions;
- Transportation and marketing of natural gas, oil, NGLs, diluents and electricity;
- Access to services and equipment to carry out exploration, development and operating activities; and
- 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, oil or NGLs, each 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 transportation 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 monitors developments in emerging climate change policy and legislation, and considers the associated costs of carbon in its strategic 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 approximately $10 to $50 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 2011, 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 $4.4 billion. As at December 31, 2011, Encana has recorded an asset retirement obligation of $1,043 million.

Social and Environmental Policies

Encana has a Corporate Responsibility Policy, an Environment Policy and a Health & Safety Policy (the "Policies") that articulate Encana's commitment to responsible development. The Policies apply to any activity undertaken by or on behalf of Encana, anywhere in the world, associated with the finding, development, production, transmission and storage of the Company's products including decommissioning of facilities, marketing and other business and administrative functions. The Corporate Responsibility Policy articulates Encana's commitment to conducting its business ethically, legally and in a manner that is fiscally, environmentally and socially responsible, while delivering strong financial performance. The Corporate Responsibility Policy has specific requirements in areas related to governance, people, environment, health and safety, engagement, and community involvement.

With respect to Encana's relationship with the communities in which it does business, the Corporate Responsibility Policy states that Encana will: strive to be a good neighbour by contributing to the well-being of the communities where it operates, recognizing their differing priorities and needs; engaging, listening and working with stakeholders in a timely, respectful and meaningful way; and aligning its community investments with its business strategy and seek to provide mutually beneficial relationships with the community and non-governmental organizations.

With respect to human rights, the Corporate Responsibility Policy states that Encana will abide by all applicable workplace, employment, privacy and human rights legislation. In addition, Encana will provide a respectful, inclusive workplace free from harassment, discrimination and intimidation.

The Environment Policy recognizes that responsible environmental practices contribute to long-term shareholder value creation and articulates Encana's commitment to environmental stewardship. The Environment Policy outlines specific requirements in areas related to: compliance with environmental laws and regulations; environmental risk assessment and mitigation; air emissions management; water sourcing, handling and disposal; pollution prevention and waste minimization; and habitat, plant and wildlife disturbance.

The Health & Safety Policy recognizes that all occupational injuries and illnesses are preventable and states Encana's goal of achieving a workplace free of recognized hazards, occupational injuries and illnesses.

The Policies and any revisions are approved by Encana's Executive Team and its Board of Directors. Accountability for implementation of the Policies is at the operational level within Encana's business units. Business units have established processes to evaluate risks and programs have been implemented to minimize those risks. Coordination and oversight of the Policies resides with the EH&S, Security and Corporate Responsibility Group within Corporate Development, EH&S and Reserves.

Some of the steps that Encana has taken to embed the corporate responsibility approach throughout the organization include:

- 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;
- An EH&S management system;
- A security program to regularly assess security threats to business operations and to manage the associated risks;
- A formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide and specific Aboriginal Community Engagement Guide;
- Corporate responsibility performance metrics to track the Company's progress;
- An environmental efficiency program that focuses on reducing energy and water use at Encana's operations and supports initiatives at the community level while also incenting employees to reduce energy and water use in their homes;

- A comprehensive community investment program that contributes to charitable and non-profit organizations in the communities in which Encana operates and an employee program that matches employee donations up to $25,000 per employee, per year;
- An Investigations Practice and an Investigations Committee to review and resolve potential violations of Encana policies or practices and other regulations;
- An Integrity Hotline that provides an additional avenue for Encana's stakeholders to raise their concerns, and a corporate responsibility website which allows people to write to the Company about non-financial issues of concern;
- An internal corporate EH&S audit program that evaluates Encana's compliance with the expectations and requirements of the EH&S management system; and
- Related policies and practices such as an Alcohol and Drug Policy, a Business Conduct & Ethics Practice and guidelines for correct behaviors 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 Company.

Employees

At December 31, 2011, Encana employed 4,276 full time equivalent employees ("FTE") as set forth in the following table.

	FTE Employees
Canadian Division	1,860
USA Division	1,751
Corporate	665
Total	**4,276**

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

Foreign Operations

As at December 31, 2011, all of Encana's reserves and production were located in North America, which limits Encana's exposure to risks and uncertainties in countries considered politically and economically unstable. Any 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.

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
Peter A. Dea [3,6] Denver, Colorado, U.S.A.	2010	President & Chief Executive Officer Cirque Resources LP *(Private oil & gas company)*
Randall K. Eresman [8] Calgary, Alberta, Canada	2006	President & Chief Executive Officer Encana Corporation
Claire S. Farley [3,5,6] Houston, Texas, U.S.A.	2008	Managing Director Kohlberg Kravis Roberts & Co. *(Public global investment firm)*
Fred J. Fowler [3,4] 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 [2,4] 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 [2,4] Edmonton, Alberta, Canada	2007	President Bear Investments Inc. *(Private investment company)*
Bruce G. Waterman [2,4] Calgary, Alberta, Canada	2010	Executive Vice President and Chief Strategy Development & Investment Officer Agrium Inc. *(Public agriculture supply company)*
Clayton H. Woitas [3,6] 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 11 directors of the Company. All of the current directors were elected at the last annual meeting of shareholders held on April 20, 2011. At the next annual meeting, shareholders will be asked to elect as directors each of the individuals listed in the above table, with the exception of Barry W. Harrison, who has reached the Company's mandatory retirement age restrictions for directors. The Company's mandatory retirement age restrictions, which have been established by the Board of Directors, stipulate that a director may not stand for re-election after reaching the age of 71.

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
Robert A. Grant Calgary, Alberta, Canada	Executive Vice-President, Corporate Development, EH&S and Reserves
Terrence J. Hopwood Calgary, Alberta, Canada	Executive Vice-President & General Counsel
Eric D. Marsh Denver, Colorado, U.S.A.	Executive Vice-President, Natural Gas Economy *(Senior Vice-President, USA Division)*
Michael G. McAllister Calgary, Alberta, Canada	Executive Vice-President *(Acting President, Canadian Division)*
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 is a Managing Director in Kohlberg Kravis Roberts & Co.'s ("KKR") energy and infrastructure group as of November 2011. Prior to joining KKR as an employee, Ms. Farley co-founded RPM Energy LLC (a privately-owned oil and gas exploration and development company) created in September 2010 and partnered with KKR. She was an Advisory Director of Jefferies Randall & Dewey (a private global oil and gas energy industry advisor) from August 2008 to September 2010 and was Co-President of Jefferies Randall & Dewey from February 2005 to August 2008. She was a Managing Partner of Castex Energy Partners (a private exploration and production limited partnership) from August 2008 to January 2009.

Mr. Fowler has been Chairman of Spectra Energy Partners, LP (a public entity) since October 2008. He was President & Chief Executive Officer of Spectra Energy Corp. (a natural gas gathering, processing and mainline transportation company) from December 2006 to December 2008 and served as a director from December 2006 to May 2009.

Ms. Nimocks was a director (senior partner) with McKinsey & Company (a private 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") (electrical transmission) from April 2005 to January 2009.

Mr. Waterman has been Executive Vice President and Chief Strategy Development & Investment Officer of Agrium Inc. (a public agricultural supply company) since April 2011. From April 2000 through April 2011 he was Senior Vice President, Finance & Chief Financial Officer of Agrium Inc.

Mr. Hopwood was Senior Vice President and General Counsel of Suncor Energy Inc. (a public oil and gas company) from 2002 to February 2011.

All of the directors and executive officers of Encana listed above, as a group, beneficially owned or controlled or directed, directly or indirectly, as of February 16, 2012, an aggregate of 648,885 common shares representing 0.09 percent of the issued and outstanding voting shares of Encana, and held options to acquire an aggregate of 4,199,024 additional common shares.

Investors should be aware that some of the directors and officers of the Company 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 Company.

Audit Committee Information

The full text of the Audit Committee mandate is included in ***Appendix E*** 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.

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 was Chairman and a director of The Wawanesa Mutual Insurance Company (a Canadian property and casualty insurer) and its related companies, The Wawanesa Life Insurance Company and its U.S. subsidiary, Wawanesa General Insurance Company, from May 1994 to May 2011. In the past ten years, he has served as either the Chairman, director or President of several intermediate and junior oil & gas companies doing business in Canada, the United States and Russia. Mr. Harrison is also a director and President of Yokara Management Inc. (a private investment company).

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 is a Corporate Director. Ms. Nimocks is a director of Rowan Companies, Inc. (a public international contract drilling services company) and ArcelorMittal (a public international steel company). She was a director (senior partner) with McKinsey & Company (a private 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). Ms. Peverett is a Corporate Director. She is a director of Northwest Natural Gas Company (a public natural gas distribution company), Canadian Imperial Bank of Commerce (one of Canada's largest banks), the B.C. Ferry Authority and Associated Electric & Gas Insurance Services Limited (a private mutual insurance company). She is also an Audit Committee member of Canadian Imperial Bank of Commerce and Northwest Natural Gas Company. She was President and Chief Executive Officer of BCTC (electrical transmission) from April 2005 to January 2009 and was previously Vice President, Corporate Services and Chief Financial Officer of BCTC 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. He is also a Fellow of the Chartered Accountants (FCA). He is President of Bear Investments Inc. (a 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). 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.

Bruce G. Waterman

Mr. Waterman holds a Bachelor of Commerce (Queen's University) and a designation as a Chartered Accountant. He is also a Fellow of the Chartered Accountants (FCA). He has been the Executive Vice President and Chief Strategy Development & Investment Officer of Agrium Inc. (a public agricultural supply company) since April 2011. From April 2000 through April 2011, he was Senior Vice President, Finance & Chief Financial Officer of Agrium. Prior to joining Agrium, Mr. Waterman was the Vice-President & Chief Financial Officer of Talisman Energy Inc. (a public oil and gas company) from January 1996 to April 2000. Mr. Waterman also has extensive expertise in oil and gas exploration and production operations, having spent 15 years (1981 to 1996) at Amoco Corporation, including Dome Petroleum Limited, a predecessor company. At Amoco (a global chemical, oil and gas company which merged with British Petroleum in 1998), his roles included various positions in finance and accounting.

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 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"). 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 Chair 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 Company for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2011 and 2010.

(C$ thousands)	**2011**	**2010**
Audit Fees [(1)]	3,136	3,243
Audit-Related Fees [(2)]	896	252
Tax Fees [(3)]	457	600
All Other Fees [(4)]	4	15
Total	**4,493**	**4,110**

Notes:

(1) Audit fees consist of fees for the audit of the Company'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 Company's financial statements and are not reported as Audit Fees. During fiscal 2011 and 2010, the services provided in this category included 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 2011 and 2010, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.

(4) During fiscal 2011 and 2010, 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 Company'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 Securities and Exchange Commission ("SEC") Regulation S-X in 2011 or 2010.

Description of Share Capital

The Company is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As of December 31, 2011, there were approximately 736.3 million common shares outstanding and no preferred shares outstanding.

Common Shares

The holders of the common shares are entitled to receive dividends if, as and when declared by the Board of Directors of the Company. 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 Company or other distribution of assets of the Company 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 Company.

Encana has stock-based compensation plans that allow employees to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date that the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the grant date.

The November 30, 2009 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 the stock options of Encana became the holders of stock options of Encana and Cenovus, with the exercise price under the stock options being adjusted based on the relative trading prices of the Encana and Cenovus common shares.

The Company has a shareholder rights plan (the "Plan") that was adopted to ensure, to the extent possible, that all shareholders of the Company are treated fairly in connection with any take-over bid for the Company. 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 amended and reconfirmed at the 2010 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 Company, but may be entitled to vote if the Company 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 Company, and the second preferred shares are entitled to priority over the common shares of the Company, with respect to the payment of dividends and the distribution of assets of the Company in the event of any liquidation, dissolution or winding up of the Company's affairs.

Credit Ratings

The following information relating to Encana's credit ratings is provided as it relates to Encana's financing costs and liquidity. Specifically, credit ratings affect Encana's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Encana to engage in certain collateralized business activities on a cost effective basis depends on the Company maintaining competitive credit ratings. A reduction in the current ratings on the Company's debt by its rating agencies, particularly a downgrade below investment grade ratings, could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, entering into normal course derivative or hedging transactions.

The following table outlines the ratings issued by the respective rating agencies as of February 16, 2011.

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

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. 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 issuer to meet its financial commitment on the obligation. S&P's short-term Canadian commercial paper ratings are on a scale that ranges from A-1 (high) to D, which represents the range from highest to lowest quality. A rating of A-2 is the fourth highest of eight categories and indicates that the issuer 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. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to obligations subject to moderate credit risk. They are considered medium grade and as such 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 rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category. Moody's short-term credit ratings are on a rating scale that ranges from P-1 to NP, which represents the range from highest to 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. A rating of A (low) by DBRS is within the third highest of ten categories and is assigned to obligations considered to be of good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of higher rated entities. The addition of a high or low modifier after a rating indicates relative standing within the category. DBRS' commercial paper and short-term debt 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 good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial, but overall strength is not as favourable as higher rating categories. The issuer may be vulnerable to future events, but qualifying negative factors are considered manageable. The trend indicates the direction that the ratings are headed should present tendencies continue.

See “Risk Factors – A downgrade in Encana’s credit rating could increase its cost of capital and limit its access to capital, suppliers or counterparties” in this annual information form.

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 under the symbol “ECA”. The following table outlines the share price trading range and volume of shares traded by month in 2011.

	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)*
2011								
January	32.59	28.39	32.27	57.9	32.67	28.52	32.27	96.9
February	33.00	30.28	31.58	59.0	33.17	30.65	32.54	94.4
March	34.25	29.42	33.53	59.4	35.06	30.12	34.53	94.2
April	33.99	30.44	31.79	42.9	35.22	31.87	33.53	65.3
May	33.68	30.71	33.02	36.0	34.85	31.78	34.10	85.2
June	33.30	28.13	29.78	51.2	34.33	28.67	30.79	91.1
July	30.42	27.96	28.03	35.0	32.23	29.27	29.29	69.4
August	28.04	22.92	24.87	61.3	29.89	23.09	25.41	134.4
September	25.14	19.86	20.17	56.2	25.75	18.99	19.21	96.2
October	22.32	18.71	21.62	51.7	22.51	17.64	21.70	103.9
November	21.81	18.62	20.55	49.6	21.59	17.76	20.05	94.6
December	20.89	18.40	18.89	43.6	20.62	17.75	18.53	101.5

During 2011, 2010 and 2009, Encana had approval from the TSX to purchase common shares under a Normal Course Issuer Bid (“NCIB”). The Company did not purchase any of its common shares under its NCIB program during 2011. During 2010, the Company purchased approximately 15.4 million common shares at an average price of approximately $32.42 per share for total consideration of approximately $499 million. During 2009, the Company did not purchase any of its common shares. Encana has not renewed its NCIB program, which expired on December 13, 2011.

On November 14, 2011, Encana completed a public offering in the U.S. of $600 million in senior unsecured notes with a coupon rate of 3.90 percent due November 15, 2021 and $400 million in senior unsecured notes with a coupon rate of 5.15 percent due November 15, 2041.

Dividends

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. During 2011 and 2010, Encana paid a quarterly dividend of $0.20 per share (2011 - $0.80 per share annually; 2010 - $0.80 per share annually). For the first three quarters of 2009, Encana paid a quarterly dividend of $0.40 per share. Following the Split Transaction, in the fourth quarter of 2009, Encana paid a quarterly dividend of $0.20 per share (2009 - $1.40 per share annually).

Legal Proceedings

The Company 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 Company does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Company 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. When assessing the materiality of the foregoing risk factors, Encana takes into account a number of qualitative and quantitative factors, including, but not limited to, financial, operational, reputational and regulatory aspects of the identified risk factor.

A substantial or extended decline in natural gas or 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. Fluctuations in natural gas or liquids prices could have an adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for natural gas and liquids fluctuate in response to changes in the supply and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond the Company'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). A 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 and drilling commitments, all of which could have an adverse effect on the Company's revenues, profitability and cash flows.

Oil prices are determined by international supply and demand. Factors which affect 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 oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Historically, NGL prices have generally been correlated with oil prices, although they are determined based on supply and demand in international and domestic NGL markets.

On at least an annual basis, Encana conducts an assessment of the carrying value of its assets in accordance with applicable accounting standards. If natural gas or liquids prices decline, the carrying value of Encana's assets could be subject to financial downward revisions, and the Company's net earnings could be adversely affected.

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

The Company's ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond the Company'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 overall state of the capital markets, including investor appetite for investments in the oil and gas industry generally and the Company's securities in particular, the ability to secure and maintain cost effective financing for its commitments, legislative, environmental and regulatory matters, unexpected cost increases, royalties, taxes, volatility in natural gas and liquids prices, the availability of drilling and other equipment, the ability to access lands, the ability to access water for hydraulic fracturing operations, 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 Company'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, as well as potential impact on the Company's credit ratings, which could affect its liquidity and ability to obtain financing.

The Company 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 Company's existing and planned projects.

The Company'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 Company'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 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 certain 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. However, the Canadian federal government has gone on record as saying that it will align greenhouse gas emission legislation with the U.S. As it remains unclear what approach the U.S. federal government will take, or when, it is also unclear whether these federal governments will implement economy-wide greenhouse gas emission legislation or a sector-specific approach, and what type of compliance mechanisms will be available to certain emitters. Currently, certain provinces and states, including Alberta and British Columbia, have implemented greenhouse gas emission legislation that impacts areas in which the Company operates. It is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

Additionally, the U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in many of the jurisdictions in which the Company operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources. In addition, the U.S. Environmental Protection Agency (the "EPA") has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impacts on drinking water sources and public health. The EPA has also released a draft report outlining the results of its groundwater study at the Company's Pavillion natural gas field of Wyoming. Although the EPA's draft report has not been subject to a qualified, third-party, scientific verification, any implication of a potential connection between hydraulic fracturing and groundwater quality may have a material adverse effect on Encana's business, financial condition, results of operations or reputation.

Further, certain governments in jurisdictions where the Company does not currently operate have considered a temporary moratorium on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs or third-party or governmental claims, and could increase the Company's cost of compliance and doing business as well as reduce the amount of natural gas that the Company is ultimately able to produce from its reserves.

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 Company could face increases in operating costs in order to comply with legislation governing emissions and hydraulic fracturing.

If Encana fails to acquire or find additional reserves, the Company's reserves and production will decline materially from their current levels.

Encana's future natural gas, oil and NGL 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 Company'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, oil and NGL 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, oil and NGL reserves, including many factors beyond the Company's control. The reserves data in this annual information form represents estimates only. In general, estimates of economically recoverable natural gas, oil and NGL 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, availability of future capital, 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, oil and NGL 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 Company's operations results in exposure to fluctuations in commodity prices. The Company monitors its exposure to such fluctuations and, where the Company deems it appropriate, utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in natural gas and liquids prices.

Under IFRS, 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 Company's reported net earnings.

The terms of the Company's various hedging agreements may limit the benefit to the Company of commodity price increases. The Company may also suffer financial loss because of hedging arrangements if the Company is unable to produce natural gas, oil or NGLs to fulfill delivery obligations, or if counterparties to the Company'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 Company's business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas, oil and NGLs 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 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, oil, NGLs and other related products, drilling and completion of natural gas and oil wells, and the operation and development of natural gas and 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, 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 Company's financial position.

Fluctuations in exchange rates could affect expenses or result in realized and unrealized losses.

Worldwide prices for natural gas and oil are set in U.S. dollars. However, many of the Company'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 Company's expenses and have an adverse effect on the Company's financial performance and condition.

In addition, the Company 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 Company'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 Company'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 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 project timelines or operational efficiency.

A downgrade in Encana's credit rating could increase its cost of capital and limit its access to capital, suppliers or counterparties.

Rating agencies regularly evaluate the Company, basing their ratings of its long-term and short-term debt on a number of factors. This includes the Company's financial strength as well as factors not entirely within its control, including conditions affecting the oil and gas industry generally and the wider state of the economy. There can be no assurance that one or more of the Company's credit ratings will not be downgraded.

The Company's borrowing costs and ability to raise funds are directly impacted by its credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions, including transactions involving over-the-counter derivatives. A credit-rating downgrade could potentially impair the Company's ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit the Company's access to private and public credit markets and increase the costs of borrowing under its existing credit facilities. A downgrade could also limit the Company's access to short-term debt markets, increase the cost of borrowing in the short-term and long-term debt markets, and trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties, facility construction contracts, and pipeline and midstream service providers.

In connection with certain over-the-counter derivatives contracts and other trading agreements, the Company could be required to provide additional collateral or to terminate transactions with certain counterparties in the event of a downgrade of its credit rating. The occurrence of any of the foregoing could adversely affect the Company's ability to execute portions of its business strategy, including hedging, and could have a material adverse effect on its liquidity and capital position.

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.

The decision to pay dividends and the amount of such dividends is subject to the discretion of the Company's Board of Directors based on numerous factors and may vary from time to time.

Although the Company currently intends to pay quarterly cash dividends to its shareholders, these cash dividends may be reduced or suspended. The amount of cash available to the Company to pay dividends, if any, can vary significantly from period to period for a number of reasons, including, among other things: Encana's operational and financial performance; fluctuations in the costs to produce natural gas, oil and NGLs; the amount of cash required or retained for debt service or repayment; amounts required to fund capital expenditures and working capital requirements; access to equity markets; foreign currency exchange rates and interest rates; and the risk factors set forth in this annual information form.

The decision whether or not to pay dividends and the amount of any such dividends are subject to the discretion of the Company's Board of Directors, which regularly evaluates the Company's proposed dividend payments and the solvency test requirements of the CBCA. In addition, the level of dividends per common share will be affected by the number of outstanding common shares and other securities that may be entitled to receive cash dividends or other payments. Dividends may be increased, reduced or suspended depending on the Company's operational success and the performance of its assets. The market value of the common shares may deteriorate if the Company is unable to meet dividend expectations in the future, and that deterioration may be material.

The Company'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

The registrar and transfer agent for the Company's common shares is CIBC Mellon Trust Company:

In Canada:
Canadian Stock Transfer Company
P.O. Box 700, Station B
Montreal, Quebec H3B 3K3

In the United States:
Computershare
480 Washington Blvd.
Jersey City, New Jersey
United States of America 07310

Canadian Stock Transfer Company Inc. acts as the administrative agent for CIBC Mellon Trust Company.

In order to respond to Encana shareholder inquiries, the Company'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 1-416-682-3863

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

Interest of Experts

The Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 23, 2012 in respect of the Company's Consolidated Financial Statements as at December 31, 2011, December 31, 2010 and January 1, 2010 and for each of the years in the two year period ended December 31, 2011, and the Company's effectiveness of internal control over financial reporting as at December 31, 2011. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company 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 one percent of any class of Encana's securities.

Additional Information

Additional information relating to Encana is available on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

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, 2011.

The Arrangement Agreement and Separation and Transition Agreement, described under "General Development of the Business – Recent Developments - 2009" 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 of growing its portfolio of resource plays producing natural gas, oil and NGLs, completion of transaction agreements with Mitsubishi, including potential terms, closing date, amount of investments, funding commitment and development of otherwise undeveloped natural gas properties, anticipated date of first production at Deep Panuke gas field, drilling and development plans and the timing and location thereof, production and processing capacities, including deep cut processing agreements that will capture more value and enhance returns, and levels and the timing of achieving such capacities and levels, potential completion of divestitures of certain assets or other transactions, attaining capital and operating efficiencies, funding future development costs with joint ventures, expanding natural gas markets in North America, 2012 production estimates, expansion of gathering and processing plants and other facilities, reserves estimates, including reserves estimates under different price cases, and net present values of future net revenues for reserves using forecast prices and costs and SEC constant prices, the level of expenditures for compliance with environmental legislation and regulations, including estimates of potential costs of carbon, operating costs, site restoration costs including abandonment and reclamation costs, maintaining satisfactory credit ratings, 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 forward-looking statements will not occur, which may cause the Company’s actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same; assumptions based upon the Company’s current guidance; fluctuations in currency and interest rates; risk that the Company may not conclude divestitures of certain assets or other transactions (including third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as “joint ventures”) as a result of various conditions not being met; product supply and demand; market competition; risks inherent in the Company’s and its subsidiaries’ marketing operations, including credit risks; 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, probable or possible reserves or economic contingent resources, including future net revenue estimates; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology; the Company’s ability to acquire or find additional reserves; hedging activities resulting in realized and unrealized losses; business interruption and casualty losses; risk of the Company not operating all of its properties and assets; counterparty risk; downgrade in credit rating and its adverse effects; liability for indemnification obligations to third parties; variability of dividends to be paid; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company’s ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. In addition, assumptions relating to such forward-looking statements generally include Encana’s current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production 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 annual information form.

Assumptions with respect to forward-looking information regarding expanding Encana's oil and NGL production and extraction volumes are based on existing expansion of natural gas processing facilities in areas where Encana operates and the continued expansion and development of oil and NGL production from existing properties within its asset portfolio.

Furthermore, 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 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. Prior to 2011, Encana relied upon an exemption from NI 51-101 granted by Canadian securities regulatory authorities to permit it to provide disclosure relating to reserves and other oil and gas information in accordance with U.S. disclosure requirements. Subsequent to the expiry of that exemption, Encana has provided and continues to provide disclosure which complies with the annual disclosure requirements of NI 51-101 in its annual information form. The Canadian protocol disclosure is contained in ***Appendix A*** and under "Narrative Description of the Business". Encana has obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. That disclosure is primarily set forth in ***Appendix D***.

See "Reserves and Other Oil and Gas Information" in this annual information form for a description of the primary differences between the disclosure requirements under the Canadian standards and the disclosure requirements under the U.S. standards.

All production information contained in the narrative portions of this annual information form is on a net basis (after royalties), unless otherwise indicated.

Appendix A - Canadian Protocol Disclosure of Reserves Data and Other Oil and Gas Information

In this Appendix, Encana provides disclosure of its reserves and oil and gas information in accordance with the requirements of NI 51-101. See "Note Regarding Reserves Data and Other Oil and Gas Information". The reserves and other oil and gas information set forth below has an effective date of December 31, 2011 and was prepared as of February 15, 2012.

Since inception, Encana has retained IQREs to evaluate and prepare reports on 100 percent of Encana's natural gas, oil and NGL reserves annually. For further information regarding the reserves process, see "Reserves and Other Oil and Gas Information" in this annual information form.

The reserves data summarizes the estimated natural gas, oil and NGL reserves of Encana and the net present values of future net revenues for these reserves using forecast prices and costs, as evaluated by Encana's IQREs. The evaluations were prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") handbook. The reserves definitions used are those contained in the COGE handbook and NI 51-101.

The results of the evaluations are summarized in the tables that follow in this Appendix. All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted), royalties, development costs, production costs and well abandonment costs, but before the consideration of indirect costs such as general and administrative expenses and certain abandonment and reclamation costs. The estimated future net revenue does not necessarily represent the fair market value of Encana's reserves. There is no assurance that the forecast price and cost assumptions used in preparing the evaluations will be attained and variances could be material. The reserves estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves on Encana's properties may be greater or less than those calculated.

For further information regarding the reserves process see "Reserves and Other Oil and Gas Information" in this annual information form.

The following product types are referred to in the tables in this Appendix:

- **Coalbed Methane**, which includes coalbed methane commingled with shallow gas sands, related to the CBM key resource play in the Canadian Division.

- **Shale Gas**, which includes Horn River shale gas in the Canadian Division and Barnett and Haynesville shale gas in the USA Division.

- **Other**, which includes natural gas other than coalbed methane and shale gas. Reserves and production include the following key resource plays: Greater Sierra (excluding Horn River shale), Cutbank Ridge and Bighorn in the Canadian Division; and Jonah, Piceance and a majority of Texas in the USA Division.

- **Oil and NGLs**, which includes NGLs plus light and medium oil, of which light and medium oil is not material.

Summary of Oil and Gas Reserves [1]
(Forecast Prices and Costs; Before and After Royalties)

As at December 31, 2011

Canadian Division

	Natural Gas *(Bcf)*								Oil & NGLs *(MMbbls)*	
	Coalbed Methane		Shale Gas		Other		Total			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed producing	945	982	215	205	2,049	1,810	3,209	2,997	39.9	37.9
Developed non-producing	223	221	-	-	409	394	632	615	2.0	1.7
Undeveloped	651	637	458	426	2,117	1,932	3,226	2,995	64.6	54.8
Total Proved	1,819	1,840	673	631	4,575	4,136	7,067	6,607	106.5	94.4
Probable	411	417	681	585	1,796	1,608	2,888	2,610	42.9	35.7
Total Proved Plus Probable	**2,230**	**2,257**	**1,354**	**1,216**	**6,371**	**5,744**	**9,955**	**9,217**	**149.4**	**130.1**

USA Division

	Natural Gas *(Bcf)*								Oil & NGLs *(MMbbls)*	
	Coalbed Methane		Shale Gas		Other		Total			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed producing	-	-	651	518	3,106	2,571	3,757	3,089	24.7	20.2
Developed non-producing	-	-	2	1	325	267	327	268	5.4	4.4
Undeveloped	-	-	2,523	2,001	1,825	1,476	4,348	3,477	17.2	14.0
Total Proved	-	-	3,176	2,520	5,256	4,314	8,432	6,834	47.3	38.6
Probable	-	-	3,374	2,691	2,885	2,388	6,259	5,079	24.5	20.1
Total Proved Plus Probable	**-**	**-**	**6,550**	**5,211**	**8,141**	**6,702**	**14,691**	**11,913**	**71.8**	**58.7**

Total Encana

	Natural Gas *(Bcf)*								Oil & NGLs *(MMbbls)*	
	Coalbed Methane		Shale Gas		Other		Total			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed producing	945	982	866	723	5,155	4,381	6,966	6,086	64.6	58.1
Developed non-producing	223	221	2	1	734	661	959	883	7.4	6.1
Undeveloped	651	637	2,981	2,427	3,942	3,408	7,574	6,472	81.8	68.8
Total Proved	1,819	1,840	3,849	3,151	9,831	8,450	15,499	13,441	153.8	133.0
Probable	411	417	4,055	3,276	4,681	3,996	9,147	7,689	67.4	55.8
Total Proved Plus Probable	**2,230**	**2,257**	**7,904**	**6,427**	**14,512**	**12,446**	**24,646**	**21,130**	**221.2**	**188.8**

Notes:

(1) Definitions

a) "Gross" reserves are Encana's working interest share before the deduction of estimated royalty obligations and excluding any royalty interests.

b) "Net" reserves are Encana's working interest share after deduction of estimated royalty obligations and including Encana's royalty interests.

c) "Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

d) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

e) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves.

f) "Developed producing" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

g) "Developed non-producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

h) "Undeveloped" reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure (i.e., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable) to which they are assigned.

Summary of Net Present Value of Future Net Revenue
(Forecast Prices and Costs; Before Tax)

As at December 31, 2011

Canadian Division

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	11,307	8,317	6,533	5,393	4,612
Developed non-producing	981	724	587	500	436
Undeveloped	10,009	5,303	2,979	1,677	885
Total Proved	22,297	14,344	10,099	7,570	5,933
Probable	12,496	5,893	3,301	2,054	1,366
Total Proved Plus Probable	**34,793**	**20,237**	**13,400**	**9,624**	**7,299**

USA Division

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	12,086	8,842	6,906	5,663	4,814
Developed non-producing	1,297	926	704	559	458
Undeveloped	8,714	5,045	3,005	1,790	1,027
Total Proved	22,097	14,813	10,615	8,012	6,299
Probable	15,531	7,442	3,771	1,927	933
Total Proved Plus Probable	**37,628**	**22,255**	**14,386**	**9,939**	**7,232**

Total Encana

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	23,393	17,159	13,439	11,056	9,426
Developed non-producing	2,278	1,650	1,291	1,059	894
Undeveloped	18,723	10,348	5,984	3,467	1,912
Total Proved	44,394	29,157	20,714	15,582	12,232
Probable	28,027	13,335	7,072	3,981	2,299
Total Proved Plus Probable	**72,421**	**42,492**	**27,786**	**19,563**	**14,531**

Summary of Net Present Value of Future Net Revenue
(Forecast Prices and Costs; After Tax)

As at December 31, 2011

Canadian Division

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	10,151	7,639	6,120	5,131	4,443
Developed non-producing	735	544	444	380	333
Undeveloped	7,505	3,831	2,008	989	372
Total Proved	18,391	12,014	8,572	6,500	5,148
Probable	9,369	4,359	2,388	1,443	925
Total Proved Plus Probable	**27,760**	**16,373**	**10,960**	**7,943**	**6,073**

USA Division

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	9,509	7,057	5,557	4,579	3,903
Developed non-producing	830	598	459	368	304
Undeveloped	5,550	3,226	1,942	1,178	696
Total Proved	15,889	10,881	7,958	6,125	4,903
Probable	9,915	4,701	2,359	1,187	554
Total Proved Plus Probable	**25,804**	**15,582**	**10,317**	**7,312**	**5,457**

Total Encana

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	19,660	14,696	11,677	9,710	8,346
Developed non-producing	1,565	1,142	903	748	637
Undeveloped	13,055	7,057	3,950	2,167	1,068
Total Proved	34,280	22,895	16,530	12,625	10,051
Probable	19,284	9,060	4,747	2,630	1,479
Total Proved Plus Probable	**53,564**	**31,955**	**21,277**	**15,255**	**11,530**

Additional Information Concerning Future Net Revenue
(Forecast Prices and Costs; Undiscounted)

As at December 31, 2011

	Canadian Division		USA Division		Total	
($ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Revenues	46,960	69,736	52,493	95,467	99,453	165,203
Royalties and production / mineral taxes	4,079	6,706	12,657	22,394	16,736	29,100
Operating costs	12,321	17,276	8,597	14,986	20,918	32,262
Development costs	7,296	9,846	8,249	19,259	15,545	29,105
Abandonment costs	967	1,115	893	1,200	1,860	2,315
Future net revenue, before income taxes	22,297	34,793	22,097	37,628	44,394	72,421
Income tax	3,906	7,033	6,208	11,824	10,114	18,857
Future net revenue, after income taxes	**18,391**	**27,760**	**15,889**	**25,804**	**34,280**	**53,564**

Future Net Revenue by Production Group
(Forecast Prices and Costs)

As at December 31, 2011

	Natural Gas				Total	
	Coalbed Methane and Shale Gas (1)		Associated and Non-associated Gas (2)			
(discounted at 10%/yr, $ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Future Net Revenue Before Income Taxes	5,269	8,128	15,445	19,658	20,714	27,786
Unit Value *($/Mcf)* (3)	1.06	0.94	1.83	1.58	1.54	1.32

Notes:
(1) Includes by-products.
(2) Including by-products as well as future net revenue from oil (including solution gas and other by-products) which is not material.
(3) Unit values are based on net natural gas reserves volumes.

Pricing Assumptions (Forecast Prices)

The following pricing and exchange rate assumptions were utilized by the independent qualified reserves evaluators in estimating Encana's reserves data using forecast prices and costs. These assumptions were provided by Encana, based on GLJ Petroleum Consultants Ltd. pricing information, and are the same pricing assumptions used for the business case included in "Net Proved Reserves (U.S. Protocol)" in ***Appendix D*** in this annual information form.

	Natural Gas		**Oil and NGLs**		**Foreign Exchange Rate** [2]	**Inflation Rate**[3]
Year	Henry Hub *($/MMBtu)*	AECO *(C$/MMBtu)*	WTI *($/bbl)*	Edmonton [1] *(C$/bbl)*	*US$/C$*	*%/yr*
2011 [4,5]	4.04	3.67	95.11	95.56	1.01	3.0
2012	3.80	3.49	97.00	97.96	0.98	2.0
2013	4.50	4.13	100.00	101.02	0.98	2.0
2014	5.00	4.59	100.00	101.02	0.98	2.0
2015	5.50	5.05	100.00	101.02	0.98	2.0
2016	6.00	5.51	100.00	101.02	0.98	2.0
2017-2021	6.50 - 7.17	5.97 - 6.58	100.00 - 107.56	101.02 - 108.73	0.98	2.0
Thereafter:	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.98	2.0

Notes:

(1) Light Sweet at Edmonton.

(2) The exchange rates used to generate the Canadian benchmark reference prices in this table.

(3) Default cost inflation rate. Abnormal inflationary situations in certain regions are handled individually by directly increasing the cost estimates for the years affected.

(4) Actual weighted average historical prices for 2011.

(5) Encana's weighted average prices for 2011 excluding the impact of realized hedging were $4.18/Mcf for natural gas and $85.20/bbl for oil & NGLs.

Reconciliation of Changes in Reserves (Before Royalties)

The following tables provide a reconciliation of Encana's gross reserves of natural gas, oil and NGLs for the year ended December 31, 2011, presented using forecast prices and costs.

Proved Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*	**Total** *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	1,810	511	4,434	6,755	61.9	7,126
Extensions and improved recovery	148	138	522	808	48.9	1,101
Technical revisions	32	225	132	389	6.5	428
Discoveries	-	-	10	10	0.8	15
Acquisitions	25	-	57	82	0.3	84
Dispositions	(5)	(33)	(149)	(187)	(6.1)	(223)
Economic factors	(30)	(134)	(70)	(234)	0.2	(233)
Production	(161)	(34)	(361)	(556)	(6.0)	(592)
December 31, 2011	**1,819**	**673**	**4,575**	**7,067**	**106.5**	**7,706**

USA Division

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*	**Total** *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	-	3,445	5,854	9,299	47.4	9,584
Extensions and improved recovery	-	675	211	886	1.8	898
Technical revisions	-	587	(14)	573	2.4	587
Discoveries	-	-	1	1	1.9	12
Acquisitions	-	-	28	28	-	28
Dispositions	-	(1,100)	(216)	(1,316)	(1.8)	(1,327)
Economic factors	-	(138)	(44)	(182)	(0.1)	(183)
Production	-	(293)	(564)	(857)	(4.3)	(883)
December 31, 2011	**-**	**3,176**	**5,256**	**8,432**	**47.3**	**8,716**

Total Encana

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*	**Total** *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	1,810	3,956	10,288	16,054	109.3	16,710
Extensions and improved recovery	148	813	733	1,694	50.7	1,999
Technical revisions	32	812	118	962	8.9	1,015
Discoveries	-	-	11	11	2.7	27
Acquisitions	25	-	85	110	0.3	112
Dispositions	(5)	(1,133)	(365)	(1,503)	(7.9)	(1,550)
Economic factors	(30)	(272)	(114)	(416)	0.1	(416)
Production	(161)	(327)	(925)	(1,413)	(10.3)	(1,475)
December 31, 2011	**1,819**	**3,849**	**9,831**	**15,499**	**153.8**	**16,422**

Probable Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	463	502	1,695	2,660	23.1	2,799
Extensions and improved recovery	44	102	261	407	22.3	540
Technical revisions	(94)	(78)	(84)	(256)	(0.6)	(260)
Discoveries	-	-	16	16	1.6	26
Acquisitions	6	79	10	95	-	95
Dispositions	(1)	(18)	(94)	(113)	(3.9)	(137)
Economic factors	(7)	94	(8)	79	0.4	82
Production	-	-	-	-	-	-
December 31, 2011	**411**	**681**	**1,796**	**2,888**	**42.9**	**3,145**

USA Division

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	-	3,528	3,765	7,293	29.3	7,468
Extensions and improved recovery	-	1,994	911	2,905	4.0	2,928
Technical revisions	-	(1,771)	(1,741)	(3,512)	(10.0)	(3,571)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	45	45	1.3	53
Dispositions	-	(286)	(54)	(340)	(0.1)	(340)
Economic factors	-	(91)	(41)	(132)	-	(132)
Production	-	-	-	-	-	-
December 31, 2011	**-**	**3,374**	**2,885**	**6,259**	**24.5**	**6,406**

Total Encana

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	463	4,030	5,460	9,953	52.4	10,267
Extensions and improved recovery	44	2,096	1,172	3,312	26.3	3,468
Technical revisions	(94)	(1,849)	(1,825)	(3,768)	(10.6)	(3,831)
Discoveries	-	-	16	16	1.6	26
Acquisitions	6	79	55	140	1.3	148
Dispositions	(1)	(304)	(148)	(453)	(4.0)	(477)
Economic factors	(7)	3	(49)	(53)	0.4	(50)
Production	-	-	-	-	-	-
December 31, 2011	**411**	**4,055**	**4,681**	**9,147**	**67.4**	**9,551**

Proved Plus Probable Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	2,273	1,013	6,129	9,415	85.0	9,925
Extensions and improved recovery	192	240	783	1,215	71.2	1,641
Technical revisions	(62)	147	48	133	5.9	168
Discoveries	-	-	26	26	2.4	41
Acquisitions	31	79	67	177	0.3	179
Dispositions	(6)	(51)	(243)	(300)	(10.0)	(360)
Economic factors	(37)	(40)	(78)	(155)	0.6	(151)
Production	(161)	(34)	(361)	(556)	(6.0)	(592)
December 31, 2011	**2,230**	**1,354**	**6,371**	**9,955**	**149.4**	**10,851**

USA Division

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	-	6,973	9,619	16,592	76.7	17,052
Extensions and improved recovery	-	2,669	1,122	3,791	5.8	3,826
Technical revisions	-	(1,184)	(1,755)	(2,939)	(7.6)	(2,984)
Discoveries	-	-	1	1	1.9	12
Acquisitions	-	-	73	73	1.3	81
Dispositions	-	(1,386)	(270)	(1,656)	(1.9)	(1,667)
Economic factors	-	(229)	(85)	(314)	(0.1)	(315)
Production	-	(293)	(564)	(857)	(4.3)	(883)
December 31, 2011	**-**	**6,550**	**8,141**	**14,691**	**71.8**	**15,122**

Total Encana

	Natural Gas *(Bcf)*				Oil & NGLs *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2010	2,273	7,986	15,748	26,007	161.7	26,977
Extensions and improved recovery	192	2,909	1,905	5,006	77.0	5,467
Technical revisions	(62)	(1,037)	(1,707)	(2,806)	(1.7)	(2,816)
Discoveries	-	-	27	27	4.3	53
Acquisitions	31	79	140	250	1.6	260
Dispositions	(6)	(1,437)	(513)	(1,956)	(11.9)	(2,027)
Economic factors	(37)	(269)	(163)	(469)	0.5	(466)
Production	(161)	(327)	(925)	(1,413)	(10.3)	(1,475)
December 31, 2011	**2,230**	**7,904**	**14,512**	**24,646**	**221.2**	**25,973**

Undeveloped Reserves, Significant Factors or Uncertainties and Future Development Costs

Undeveloped Reserves

Proved and probable undeveloped reserves are attributed where warranted on the basis of technical merit, commercial considerations and development plans. These development opportunities are being pursued at a pace dependent on capital availability and allocation. As a result, development is scheduled beyond the next two years. All of the proved and probable undeveloped reserves at December 31, 2011 are scheduled for development within the next five and eight years respectively in Canada and the United States.

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time.

Proved Undeveloped Reserves

	Natural Gas *(Bcf)*								**Oil & NGLs** *(MMbbls)*	
	Coalbed Methane		**Shale Gas**		**Other**		**Total**			
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	923	923	368	368	4,611	4,611	5,902	5,902	42.1	42.1
2009	-	559	832	1,217	1,222	4,500	2,054	6,276	11.6	38.1
2010	282	688	1,161	2,808	1,105	4,449	2,548	7,945	18.7	53.8
2011	73	651	657	2,981	914	3,942	1,644	7,574	21.8	81.8

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time.

Probable Undeveloped Reserves

	Natural Gas *(Bcf)*								**Oil & NGLs** *(MMbbls)*	
	Coalbed Methane		**Shale Gas**		**Other**		**Total**			
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	166	166	593	593	4,671	4,671	5,430	5,430	46.9	46.9
2009	-	182	1,771	2,264	1,421	4,419	3,192	6,865	10.1	41.8
2010	67	290	2,289	3,889	1,459	4,901	3,815	9,080	12.9	42.6
2011	36	232	2,017	3,880	1,176	4,085	3,229	8,197	15.5	52.7

Significant Factors or Uncertainties

The development schedule of our undeveloped reserves is based on forecast price assumptions for the determination of economic projects. The actual prices that occur may be significantly lower or higher resulting in some projects being delayed or accelerated, as the case may be. For further information see “Risk Factors” in this annual information form.

Our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control.

Future Development Costs

The table below summarizes Encana’s development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves, using undiscounted forecast prices and costs.

	Canadian Division		**USA Division**		**Total Encana**	
($ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
2012	1,204	1,319	964	1,310	2,168	2,629
2013	1,650	1,883	1,684	2,306	3,334	4,189
2014	1,425	1,865	2,007	2,849	3,432	4,714
2015	1,197	1,623	1,680	2,621	2,877	4,244
2016	920	1,757	1,684	3,059	2,604	4,816
Remainder	900	1,399	230	7,114	1,130	8,513
Total	**7,296**	**9,846**	**8,249**	**19,259**	**15,545**	**29,105**

Future development costs are associated with reserves as evaluated by the IQREs and do not necessarily represent Encana’s exploration and development budget. Encana expects to fund its future development costs with future cash flow, available cash balances, divestitures, joint ventures, or a combination of these.

Abandonment, Tax and Costs Incurred

Abandonment and Reclamation Costs

Encana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. The asset retirement obligation (“ARO”) is estimated by discounting the expected future cash flows of the settlement. The discounted cash flows are based on estimates of reserve lives, retirement costs, discount rates and future inflation rates. In 2011, 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 is estimated at approximately $4.4 billion ($415 million discounted at 10 percent). As at December 31, 2011, Encana has recorded an asset retirement obligation of $1,043 million. These estimates include the abandonment of 21,469 net wells. Over the next three years, Encana’s net well abandonment and reclamation cost is expected to total $138 million ($120 million discounted at 10 percent).

For the purposes of the reserves evaluations prepared by the IQREs, costs deducted as abandonment costs in estimating future net revenue do not include reclamation costs or abandonment costs of facilities and wells without reserves.

Tax Horizon

On a consolidated basis, Encana was not cash taxable for 2011. The Company currently estimates it will not be cash taxable until 2013; however, the cash tax forecast may be revised for factors including the outlook for natural gas, oil and NGL commodity prices, and the expectations for capital investments, including acquisition and disposition transactions, by the Company.

2011 Costs Incurred

($ millions)	**Canadian Division**	**USA Division**	**Total**
Acquisitions			
Unproved	261	53	314
Proved	149	52	201
Total acquisitions	410	105	515
Exploration costs	174	181	355
Development costs	1,848	2,242	4,090
Total costs incurred	**2,432**	**2,528**	**4,960**

Location of Oil and Gas Wells

The following table summarizes Encana's interests in natural gas or oil wells which are producing, or the Company considers capable of production, as at December 31, 2011.

For additional information on the location of Encana's properties, plants, facilities and installations, refer to "Narrative Description of the Business" in this annual information form.

	Producing Gas		**Producing Oil**		**Total Producing (1,2)**		**Non-Producing Gas**		**Non-Producing Oil**		**Total Non- Producing (3)**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	12,293	11,131	232	162	12,525	11,293	1,333	1,073	218	169	1,551	1,242
British Columbia	1,579	1,447	1	-	1,580	1,447	295	255	4	1	299	256
Total Canadian Division	**13,872**	**12,578**	**233**	**162**	**14,105**	**12,740**	**1,628**	**1,328**	**222**	**170**	**1,850**	**1,498**
Colorado	4,821	3,925	3	-	4,824	3,925	209	169	-	-	209	169
Texas	776	495	1	1	777	496	14	6	1	-	15	6
Wyoming	1,803	1,441	1	-	1,804	1,441	80	62	-	-	80	62
Utah	3	3	-	-	3	3	-	-	-	-	-	-
Louisiana	412	218	1	1	413	219	83	29	-	-	83	29
Kansas	1	1	-	-	1	1	-	-	-	-	-	-
Michigan	-	-	1	-	1	-	5	5	-	-	5	5
Mississippi	-	-	1	1	1	1	-	-	-	-	-	-
Montana	-	-	-	-	-	-	1	1	-	-	1	1
Total USA Division	**7,816**	**6,083**	**8**	**3**	**7,824**	**6,086**	**392**	**272**	**1**	**-**	**393**	**272**
Total Encana	**21,688**	**18,661**	**241**	**165**	**21,929**	**18,826**	**2,020**	**1,600**	**223**	**170**	**2,243**	**1,770**

Notes:

(1) Encana has varying royalty interests in approximately 9,407 natural gas wells and approximately 6,416 oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows; approximately 25,063 gross natural gas wells (23,400 net wells) and approximately 158 gross oil (121 net wells).

(3) "Non-producing" wells refer to wells that are capable of producing oil or natural gas, but which are not producing due to the timing of well completions and/or waiting to be tied in which is anticipated to occur in 2012, or are wells that are temporarily shut-in due to market conditions, but not yet abandoned. All non-producing oil and natural gas wells considered capable of producing are located near existing infrastructure and/or within economic distance of transportation.

Landholdings with No Attributed Reserves

The following table summarizes the gross and net acres with no attributed reserves in which Encana has an interest at December 31, 2011 and the net acres with no attributed reserves for which we expect our rights to explore, develop and exploit to expire during 2012.

(thousands of acres)	**Gross Acres [(1)]**	**Net Acres [(1)]**	**Net Acres Expiring Within One Year**
Canada			
Alberta	4,557	3,968	180
British Columbia	2,122	1,707	364
Newfoundland and Labrador	35	2	-
Nova Scotia	21	10	-
Northwest Territories	45	12	-
Total Canada	**6,780**	**5,699**	**544**
United States			
Colorado	806	774	15
Texas	322	248	35
Wyoming	322	287	12
Louisiana	195	195	28
Michigan	430	430	-
Mississippi	173	164	25
Other	34	29	1
Total United States	**2,282**	**2,127**	**116**
International			
Australia	104	40	-
Total International	**104**	**40**	**-**
Total	**9,166**	**7,866**	**660**

Note:

(1) Properties with different formations under the same surface area and subject to separate leases have been calculated on an aerial basis, as such gross and net acreage have only been counted once.

Exploration and Development Activities

The following tables summarize Encana's gross participation and net interest in wells drilled for the periods indicated. See "Narrative Description of the Business" in this annual information form, for discussion on Encana's most important current and likely exploration and development activities.

Exploration Wells Drilled [1,2]

	Gas		Oil		Service		Dry and Abandoned		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2011 [3]											
Canadian Division	30	19	-	-	2	1	-	-	31	63	20
USA Division	19	6	3	3	-	-	-	-	5	27	9
Total	**49**	**25**	**3**	**3**	**2**	**1**	**-**	**-**	**36**	**90**	**29**

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, 2011, Encana was in the process of drilling the following exploratory and development wells: approximately 19 gross wells (17 net wells) in Canada and approximately 89 gross wells (52 net wells) in the United States.

Development Wells Drilled [1,2]

	Gas		Oil		Service		Dry and Abandoned		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2011 [3]											
Canadian Division	725	706	2	2	10	6	-	-	221	958	714
USA Division	695	392	-	-	3	3	5	1	206	909	396
Total	**1,420**	**1,098**	**2**	**2**	**13**	**9**	**5**	**1**	**427**	**1,867**	**1,110**

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, 2011, Encana was in the process of drilling the following exploratory and development wells: approximately 19 gross wells (17 net wells) in Canada and approximately 89 gross wells (52 net wells) in the United States.

Production Volumes (Before Royalties)

2012 Production Estimates (Before Royalties)

The following table summarizes the total volume of production estimated for the year ended December 31, 2012, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "Reserves Data (Canadian Protocol)" in this Appendix above.

Canadian Division

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*
(annual)	Coalbed Methane	Shale Gas	Other	Total	
Proved	151	37	422	610	7.8
Probable	4	3	14	21	0.4
Total Proved Plus Probable	**155**	**40**	**436**	**631**	**8.2**

USA Division

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*
(annual)	Coalbed Methane	Shale Gas	Other	Total	
Proved	-	247	507	754	4.1
Probable	-	10	20	30	0.1
Total Proved Plus Probable	**-**	**257**	**527**	**784**	**4.2**

Total Encana

	Natural Gas *(Bcf)*				**Oil & NGLs** *(MMbbls)*
(annual)	Coalbed Methane	Shale Gas	Other	Total	
Proved	151	284	929	1,364	11.9
Probable	4	13	34	51	0.5
Total Proved Plus Probable	**155**	**297**	**963**	**1,415**	**12.4**

2011 Production Volumes by Country
(Before Royalties)

	2011				
(average daily)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**
Coalbed Methane *(MMcf/d)*					
Canadian Division	440	455	435	438	434
USA Division	-	-	-	-	-
	440	455	435	438	434
Shale Gas *(MMcf/d)*					
Canadian Division	92	109	101	87	71
USA Division	808	921	836	795	677
	900	1,030	937	882	748
Other *(MMcf/d)*					
Canadian Division	989	1,026	985	992	951
USA Division	1,544	1,516	1,541	1,541	1,576
	2,533	2,542	2,526	2,533	2,527
Total Produced Gas *(MMcf/d)*					
Canadian Division	1,521	1,590	1,521	1,517	1,456
USA Division	2,352	2,437	2,377	2,336	2,253
	3,873	4,027	3,898	3,853	3,709
Total Oil & NGLs *(Mbbls/d)*					
Canadian Division	16.5	16.0	17.3	16.7	16.1
USA Division	11.7	12.5	11.4	11.6	11.1
	28.2	28.5	28.7	28.3	27.2

Per-Unit Results (Before Royalties)

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

Netbacks by Country (Before Royalties)

	2011				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Coalbed Methane *($/Mcf)*					
Canadian Division and Total Encana					
Price, before royalties	3.64	3.32	3.75	3.83	3.69
Royalties	0.06	0.07	0.07	0.05	0.05
Production and mineral taxes	0.06	0.05	0.05	0.07	0.08
Transportation	0.16	0.14	0.17	0.16	0.15
Operating	1.26	1.15	1.25	1.18	1.44
	2.10	**1.91**	**2.21**	**2.37**	**1.97**
Shale Gas *($/Mcf)*					
Canadian Division					
Price, before royalties	3.22	2.82	3.17	3.50	3.54
Royalties	0.05	0.04	0.05	0.06	0.06
Production and mineral taxes	-	-	-	-	-
Transportation	0.78	0.78	0.79	0.81	0.72
Operating	0.58	0.67	0.05	0.64	1.15
	1.81	1.33	2.28	1.99	1.61
USA Division					
Price, before royalties	4.15	3.69	4.39	4.36	4.22
Royalties	0.88	0.83	0.95	0.88	0.87
Production and mineral taxes	0.03	0.03	0.04	0.03	0.03
Transportation	0.77	0.68	0.82	0.86	0.71
Operating	0.56	0.45	0.48	0.58	0.78
	1.91	1.70	2.10	2.01	1.83
Total Encana					
Price, before royalties	4.05	3.60	4.26	4.28	4.16
Royalties	0.80	0.75	0.85	0.80	0.79
Production and mineral taxes	0.03	0.03	0.04	0.03	0.03
Transportation	0.77	0.69	0.82	0.85	0.71
Operating	0.56	0.48	0.44	0.58	0.82
	1.89	**1.65**	**2.11**	**2.02**	**1.81**
Other *($/Mcf)*					
Canadian Division					
Price, before royalties	3.88	3.54	4.00	4.05	3.96
Royalties	0.20	0.19	0.18	0.23	0.20
Production and mineral taxes	-	-	0.01	-	-
Transportation	0.53	0.54	0.54	0.54	0.52
Operating	1.02	0.99	0.91	1.06	1.13
	2.13	1.82	2.36	2.22	2.11

Netbacks by Country
(Before Royalties)

	2011				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Other *($/Mcf)*					
USA Division					
Price, before royalties	4.60	4.24	4.82	4.78	4.56
Royalties	0.87	0.91	0.95	0.82	0.80
Production and mineral taxes	0.26	0.24	0.24	0.29	0.29
Transportation	0.89	0.88	0.83	0.95	0.91
Operating	0.46	0.48	0.40	0.42	0.54
	2.12	1.73	2.40	2.30	2.02
Total Encana					
Price, before royalties	4.32	3.96	4.50	4.50	4.33
Royalties	0.61	0.62	0.65	0.59	0.57
Production and mineral taxes	0.16	0.14	0.15	0.18	0.18
Transportation	0.75	0.74	0.72	0.79	0.76
Operating	0.68	0.68	0.60	0.67	0.77
	2.12	**1.78**	**2.38**	**2.27**	**2.05**
Total Produced Gas *($/Mcf)*					
Canadian Division					
Price, before royalties	3.77	3.43	3.88	3.96	3.86
Royalties	0.15	0.15	0.14	0.17	0.15
Production and mineral taxes	0.02	0.01	0.02	0.02	0.02
Transportation	0.44	0.44	0.45	0.44	0.42
Operating	1.06	1.01	0.95	1.07	1.23
	2.10	1.82	2.32	2.26	2.04
USA Division					
Price, before royalties	4.45	4.03	4.67	4.64	4.46
Royalties	0.87	0.88	0.95	0.84	0.82
Production and mineral taxes	0.18	0.16	0.17	0.20	0.21
Transportation	0.85	0.80	0.83	0.92	0.85
Operating	0.49	0.47	0.43	0.47	0.62
	2.06	1.72	2.29	2.21	1.96
Total Encana					
Price, before royalties	4.18	3.79	4.36	4.37	4.22
Royalties	0.59	0.59	0.63	0.58	0.56
Production and mineral taxes	0.12	0.10	0.11	0.13	0.14
Transportation	0.69	0.66	0.68	0.73	0.68
Operating	0.72	0.68	0.63	0.71	0.86
	2.06	**1.76**	**2.31**	**2.22**	**1.98**
Total Oil & NGLs *($/bbl)*					
Canadian Division					
Price, before royalties	85.09	86.13	83.79	91.77	78.47
Royalties	10.07	11.01	10.36	9.88	9.00
Production and mineral taxes	0.79	1.07	0.56	0.55	1.00
Transportation	0.82	0.59	1.00	1.04	0.61
Operating	1.53	1.73	1.18	1.47	1.79
	71.88	71.73	70.69	78.83	66.07
USA Division					
Price, before royalties	85.37	84.13	80.53	93.69	83.08
Royalties	16.18	16.57	15.47	17.43	15.17
Production and mineral taxes	6.11	5.62	4.77	7.64	6.48
Transportation	0.07	0.19	0.07	-	-
Operating	0.57	1.65	0.50	-	-
	62.44	60.10	59.72	68.62	61.43

Netbacks by Country
(Before Royalties)

	2011				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Total Oil & NGLs *($/bbl)*					
Total Encana					
Price, before royalties	85.20	85.25	82.49	92.55	80.35
Royalties	12.60	13.44	12.39	12.98	11.52
Production and mineral taxes	2.99	3.06	2.23	3.46	3.24
Transportation	0.51	0.41	0.63	0.61	0.36
Operating	1.13	1.69	0.91	0.87	1.06
	67.97	**66.65**	**66.33**	**74.63**	**64.17**

Impact of Realized Hedging on Encana's Netbacks

	2011				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *($/Mcf)*					
Canadian Division	0.66	0.89	0.55	0.56	0.62
USA Division	0.70	0.92	0.63	0.59	0.64
Total	0.68	0.91	0.60	0.58	0.63

Appendix B - Report on Reserves Data by Independent Qualified Reserves Evaluators (Canadian Protocol)

To the Board of Directors of Encana Corporation (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2011 prepared in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") of the Canadian Securities Administrators. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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).

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 presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast 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, 2011:

Independent Qualified Reserves Evaluator	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) (US$millions)
McDaniel & Associates Consultants Ltd.	January 19, 2012	Canada	3,310
GLJ Petroleum Consultants Ltd.	January 20, 2012	Canada	10,090
Netherland, Sewell & Associates, Inc.	January 24, 2012	United States	9,186
DeGolyer and MacNaughton	January 31, 2012	United States	5,200
Total			**27,786**

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, consistently applied.

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.

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 15, 2012

Appendix C - Report of Management and Directors on Reserves Data and Other Information (Canadian Protocol)

Management of Encana Corporation (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs, prepared in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") of the Canadian Securities Administrators.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with 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 affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The board of directors of the Corporation (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 reserves data and other oil and gas information prepared in accordance with the requirements of NI 51-101 contained in the annual information form of the Corporation;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; 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.

(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 16, 2012

Appendix D - U.S. Protocol Disclosure of Reserves Data and Other Oil and Gas Information

In this Appendix, Encana provides select disclosure of its reserves and other oil and gas information prepared in accordance with U.S. disclosure requirements. See “Note Regarding Reserves Data and Other Oil and Gas Information”.

Since inception, Encana has retained IQREs to evaluate and prepare reports on 100 percent of Encana’s natural gas, oil and NGL reserves annually. For further information regarding the reserves process, see “Reserves and Other Oil and Gas Information” in this annual information form.

The standards of the SEC require that proved reserves be estimated using existing economic conditions (constant pricing). Based on this methodology, Encana’s results have been calculated utilizing the 12-month average price for each of the years presented within this Appendix.

Encana’s 2011 and 2010 financial results were prepared in accordance with IFRS. As Encana’s IFRS transition date was January 1, 2010, 2009 results were prepared in accordance with previous GAAP. Encana’s 2009 upstream results include the operations from the Canadian upstream assets that were transferred to Cenovus. Under previous GAAP full cost accounting requirements, the results from the Cenovus upstream assets were reported as continuing operations, which are referred to as “Canada – Other” in the following tables.

Net Proved Reserves (U.S. Protocol)

Natural Gas Reserves

In 2011, Encana’s proved natural gas reserves decreased by approximately three percent, due to dispositions and the impact of lower 12-month average prices more than offsetting successful development and delineation activity. Additions excluding the purchase and sale of lands with reserves attributable to them totaled 1,746 Bcf, split approximately one-half in the U.S. and one-half in Canada.

In 2010, Encana’s proved natural gas reserves increased by approximately 20 percent, largely as a result of successful development and delineation activity as well as higher 12-month average prices. Technical revisions were positive. Additions excluding purchase and sale of lands with reserves attributable to them totaled 3,542 Bcf, of which approximately two-thirds were in the U.S. and the balance was in Canada.

In 2009, Encana’s proved natural gas reserves decreased by approximately 19 percent, 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 Bcf, of which approximately two-thirds were in the U.S. and the balance was in Canada.

Oil & NGL Reserves

In 2011, Encana’s proved oil and NGL reserves increased by approximately 44 percent primarily due to activities in Canada.

In 2010, Encana’s proved oil and NGL reserves increased by approximately 21 percent as a result of activities and plans to further capture additional NGLs associated with natural gas production.

In 2009, Encana’s proved oil and NGL reserves decreased by approximately 77 percent and Encana’s bitumen reserves were divested, substantially all as a result of the Split Transaction.

Net Proved Reserves [1,2]
(SEC Constant Pricing; After Royalties)

	Natural Gas *(Bcf)*			Oil and NGLs *(MMbbls)*			Bitumen [3] *(MMbbls)*
	Canada	United States	Total	Canada	United States	Total	Canada
2009							
Beginning of year	7,847	5,831	13,678	285.6	51.6	337.2	668.4
Revisions and improved recovery [4]	(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 [5]	(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**	**-**
2010							
Beginning of year	5,349	5,713	11,062	35.5	41.2	76.7	-
Revisions and improved recovery	150	517	667	13.6	0.2	13.8	-
Extensions and discoveries	1,067	1,808	2,875	11.5	4.7	16.2	-
Purchase of reserves in place	116	81	197	0.4	0.5	0.9	-
Sale of reserves in place	(82)	(257)	(339)	(1.9)	(4.9)	(6.8)	-
Production	(483)	(679)	(1,162)	(4.8)	(3.5)	(8.3)	-
End of year	6,117	7,183	13,300	54.3	38.2	92.5	-
Developed	3,132	3,678	6,810	24.9	24.0	48.9	-
Undeveloped	2,985	3,505	6,490	29.4	14.2	43.6	-
Total	**6,117**	**7,183**	**13,300**	**54.3**	**38.2**	**92.5**	**-**
2011							
Beginning of year	6,117	7,183	13,300	54.3	38.2	92.5	-
Revisions and improved recovery	3	(204)	(201)	32.3	(0.7)	31.6	-
Extensions and discoveries	826	1,121	1,947	18.2	5.4	23.6	-
Purchase of reserves in place	72	23	95	0.2	0.1	0.3	-
Sale of reserves in place	(158)	(927)	(1,085)	(4.7)	(1.3)	(6.0)	-
Production	(531)	(685)	(1,216)	(5.3)	(3.5)	(8.8)	-
End of year	6,329	6,511	12,840	95.0	38.2	133.2	-
Developed	3,523	3,286	6,809	39.6	24.4	64.0	-
Undeveloped	2,806	3,225	6,031	55.4	13.8	69.2	-
Total	**6,329**	**6,511**	**12,840**	**95.0**	**38.2**	**133.2**	**-**

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, oil and NGL 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.

(4) 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.

(5) The transfer of the Canadian 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 oil and NGLs and for bitumen during 2009.

Pricing Assumptions (SEC Constant Pricing)

The following reference prices were utilized in the determination of reserves and future net revenue:

	Natural Gas		**Oil and NGLs**	
	Henry Hub *($/MMBtu)*	AECO *(C$/MMBtu)*	WTI *($/bbl)*	Edmonton [1] *(C$/bbl)*
Reserve Pricing [2]				
2009	3.87	3.77	61.18	65.64
2010	4.38	4.03	79.43	76.22
2011	4.12	3.76	96.19	96.53

Notes:

(1) Light Sweet for 2011 and 2010; Mixed Sweet Blend for 2009.

(2) All prices were held constant in all future years when estimating net revenues and reserves.

Sensitivity of 2011 Reserves to Prices

The following table summarizes Encana's estimates of its proved reserves as at December 31, 2011 based on the 2011 12-month average prices ("SEC Constant Pricing case") and on the prices set forth below:

	Natural Gas *(Bcf)*			Oil and NGLs *(MMbbls)*		
	Canada	United States	Total	Canada	United States	Total
Price Case						
SEC Constant Pricing case	6,329	6,511	12,840	95.0	38.2	133.2
Business case (forecast prices)	6,607	6,834	13,441	94.4	38.6	133.0
Difference versus SEC case	4.4%	5.0%	4.7%	(0.6%)	1.0%	(0.2%)

The business case assumes the following forecast prices: natural gas – Henry Hub $3.80/MMBtu in 2012 increasing to $7.17/MMBtu in 2021, and AECO C$3.49/MMBtu in 2012 increasing to C$6.58/MMBtu in 2021; oil – WTI $97.00/bbl increasing to $107.56/bbl in 2021 and Edmonton Light Sweet C$97.96/bbl increasing to C$108.73/bbl in 2021. Beyond 2021, prices were escalated at 2% per year. These forecast pricing assumptions are the same as those used for the Canadian forecast prices included in "Pricing Assumptions (Forecast Prices)" in ***Appendix A*** to this annual information form.

Proved Undeveloped Reserves

Encana's proved undeveloped natural gas reserves represented approximately 47 percent of total proved natural gas reserves at December 31, 2011, a slight decrease from approximately 49 percent at December 31, 2010. At December 31, 2011, approximately 52 percent of Encana's proved oil and NGL reserves were undeveloped, an increase from approximately 47 percent at December 31, 2010. These changes in undeveloped reserves were predicated on technical merit, commercial considerations and development plans. All of the proved undeveloped reserves at December 31, 2011 are scheduled for development within the next five years in both Canada and the United States.

During 2011, approximately 1,220 Bcfe of proved undeveloped reserves were converted to proved developed reserves. Investments made during 2011 to convert proved undeveloped reserves to proved developed reserves were approximately $1.5 billion.

At December 31, 2011, the proved undeveloped reserves which have remained undeveloped for five years or more in both Canada and the United States were not material.

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 IQREs 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 oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to Encana's Market Optimization interests.

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

	Canada			United States		
($ millions)	**2011**	**2010**	**2009** (1)	**2011**	**2010**	**2009** (1)
Future cash inflows	27,731	25,535	19,321	26,558	29,428	18,573
Less future:						
Production costs	9,717	8,676	6,296	6,195	6,894	4,862
Development costs	6,424	4,971	4,065	7,189	7,539	4,429
Asset retirement obligation payments	1,762	1,876	1,508	597	605	640
Income taxes	784	920	659	2,730	2,966	707
Future net cash flows	9,044	9,092	6,793	9,847	11,424	7,935
Less 10% annual discount for estimated timing of cash flows	3,759	3,803	2,704	4,384	5,277	3,592
Discounted future net cash flows	**5,285**	**5,289**	**4,089**	**5,463**	**6,147**	**4,343**

	Total		
($ millions)	**2011**	**2010**	**2009** (1)
Future cash inflows	54,289	54,963	37,894
Less future:			
Production costs	15,912	15,570	11,158
Development costs	13,613	12,510	8,494
Asset retirement obligation payments	2,359	2,481	2,148
Income taxes	3,514	3,886	1,366
Future net cash flows	18,891	20,516	14,728
Less 10% annual discount for estimated timing of cash flows	8,143	9,080	6,296
Discounted future net cash flows	**10,748**	**11,436**	**8,432**

Notes:

(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.

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

	Canada			United States		
($ millions)	**2011**	**2010**	**2009** [1,2]	**2011**	**2010**	**2009** [1]
Balance, beginning of year	5,289	4,089	12,714	6,147	4,343	6,647
Changes resulting from:						
Sales of oil and gas produced during the period	(1,957)	(2,034)	(5,609)	(2,653)	(2,920)	(3,442)
Discoveries and extensions, net of related costs	1,161	975	1,294	887	1,243	629
Purchases of proved reserves in place	55	146	16	42	77	-
Sales and transfers of proved reserves in place	(212)	(96)	(6,492)	(1,021)	(198)	(62)
Net change in prices and production costs	522	1,647	(1,825)	733	3,832	(1,446)
Revisions to quantity estimates	188	174	(1,242)	(336)	610	(1,567)
Accretion of discount	576	433	1,572	762	465	827
Previously estimated development costs incurred net of change in future development costs	(441)	216	737	832	(289)	1,474
Other	54	(28)	150	63	144	(26)
Net change in income taxes	50	(233)	2,774	7	(1,160)	1,309
Balance, end of year	**5,285**	**5,289**	**4,089**	**5,463**	**6,147**	**4,343**

	Total		
($ millions)	**2011**	**2010**	**2009** [1,2]
Balance, beginning of year	11,436	8,432	19,361
Changes resulting from:			
Sales of oil and gas produced during the period	(4,610)	(4,954)	(9,051)
Discoveries and extensions, net of related costs	2,048	2,218	1,923
Purchases of proved reserves in place	97	223	16
Sales and transfers of proved reserves in place	(1,233)	(294)	(6,554)
Net change in prices and production costs	1,255	5,479	(3,271)
Revisions to quantity estimates	(148)	784	(2,809)
Accretion of discount	1,338	898	2,399
Previously estimated development costs incurred net of change in future development costs	391	(73)	2,211
Other	117	116	124
Net change in income taxes	57	(1,393)	4,083
Balance, end of year	**10,748**	**11,436**	**8,432**

Notes:
(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.
(2) Results prior to November 30, 2009 include reserves from the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Results of Operations

($ millions)	Canada 2011	Canada 2010	Canada 2009 [1,2]	United States 2011	United States 2010	United States 2009 [1]
Oil and gas revenues, net of royalties, and transportation	2,622	2,632	6,835	3,294	3,613	4,007
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	665	598	1,226	641	693	565
Depreciation, depletion and amortization	1,411	1,286	1,980	1,922	1,954	1,561
Operating income (loss)	546	748	3,629	731	966	1,881
Income taxes	145	211	1,059	265	350	698
Results of operations	**401**	**537**	**2,570**	**466**	**616**	**1,183**

($ millions)	Other 2011	Other 2010	Other 2009 [1]	Total 2011	Total 2010	Total 2009 [1,2]
Oil and gas revenues, net of royalties, and transportation	-	-	-	5,916	6,245	10,842
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	-	-	-	1,306	1,291	1,791
Depreciation, depletion and amortization	-	-	28	3,333	3,240	3,569
Operating income (loss)	-	-	(28)	1,277	1,714	5,482
Income taxes	-	-	-	410	561	1,757
Results of operations	**-**	**-**	**(28)**	**867**	**1,153**	**3,725**

Notes:

(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.

(2) Results prior to November 30, 2009 include results from operations of the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Capitalized Costs and Costs Incurred

Capitalized Costs

($ millions)	Canada 2011	Canada 2010	Canada 2009 [1,2]	United States 2011	United States 2010	United States 2009 [1]
Proved oil and gas properties	26,606	24,736	21,459	22,229	21,703	19,843
Unproved oil and gas properties	1,139	1,114	728	708	1,044	1,178
Total capital cost	27,745	25,850	22,187	22,937	22,747	21,021
Accumulated DD&A	14,628	13,606	11,586	10,774	8,781	7,092
Net capitalized costs	**13,117**	**12,244**	**10,601**	**12,163**	**13,966**	**13,929**

($ millions)	Other 2011	Other 2010	Other 2009 [1]	Total 2011	Total 2010	Total 2009 [1,2]
Proved oil and gas properties	-	-	-	48,835	46,439	41,302
Unproved oil and gas properties	-	-	157	1,847	2,158	2,063
Total capital cost	-	-	157	50,682	48,597	43,365
Accumulated DD&A	-	-	147	25,402	22,387	18,825
Net capitalized costs	**-**	**-**	**10**	**25,280**	**26,210**	**24,540**

Notes:
(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.
(2) Results prior to November 30, 2009 include capitalized costs related to the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Costs Incurred

($ millions)	Canada 2011	Canada 2010	Canada 2009 [1,2]	United States 2011	United States 2010	United States 2009 [1]
Acquisitions						
Unproved	261	395	46	53	97	46
Proved	149	197	178	52	44	-
Total acquisitions	410	592	224	105	141	46
Exploration costs	174	58	129	181	198	133
Development costs	1,848	2,148	2,588	2,242	2,297	1,688
Total costs incurred	**2,432**	**2,798**	**2,941**	**2,528**	**2,636**	**1,867**

($ millions)	Other 2011	Other 2010	Other 2009 [1]	Total 2011	Total 2010	Total 2009 [1,2]
Acquisitions						
Unproved	-	-	-	314	492	92
Proved	-	-	-	201	241	178
Total acquisitions	-	-	-	515	733	270
Exploration costs	-	-	2	355	256	264
Development costs	-	-	-	4,090	4,445	4,276
Total costs incurred	**-**	**-**	**2**	**4,960**	**5,434**	**4,810**

Notes:
(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.
(2) Results prior to November 30, 2009 include costs incurred from operations of the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Developed and Undeveloped Landholdings

The following table summarizes Encana's developed, undeveloped and total landholdings as at December 31, 2011.

Landholdings (1 - 7)

(thousands of acres)		Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Canada							
Alberta	— Fee	2,302	2,302	1,249	1,249	3,551	3,551
	— Crown	1,414	828	1,463	1,238	2,877	2,066
	— Freehold	244	147	75	44	319	191
		3,960	3,277	2,787	2,531	6,747	5,808
British Columbia	— Crown	889	788	2,312	1,865	3,201	2,653
	— Freehold	-	-	7	-	7	-
		889	788	2,319	1,865	3,208	2,653
Newfoundland and Labrador	— Crown	-	-	35	2	35	2
Nova Scotia	— Crown	20	20	21	10	41	30
Northwest Territories	— Crown	-	-	45	12	45	12
Total Canada		**4,869**	**4,085**	**5,207**	**4,420**	**10,076**	**8,505**
United States							
Colorado	— Federal/State	186	174	503	469	689	643
	— Freehold	107	98	106	96	213	194
	— Fee	3	3	14	14	17	17
		296	275	623	579	919	854
Texas	— Federal/State	4	2	55	53	59	55
	— Freehold	113	73	247	176	360	249
	— Fee	-	-	4	4	4	4
		117	75	306	233	423	308
Louisiana	— Federal/State	1	1	2	2	3	3
	— Freehold	145	82	211	147	356	229
	— Fee	10	6	84	65	94	71
		156	89	297	214	453	303
Michigan	— Federal/State	-	-	368	368	368	368
	— Freehold	-	-	61	61	61	61
		-	-	429	429	429	429
Mississippi	— Freehold	1	1	142	135	143	136
	— Fee	-	-	31	30	31	30
		1	1	173	165	174	166
Wyoming	— Federal/State	69	55	294	257	363	312
	— Freehold	5	4	15	12	20	16
		74	59	309	269	383	328
Other	— Federal/State	1	2	30	22	31	24
	— Freehold	1	1	7	6	8	7
		2	3	37	28	39	31
Total United States		**646**	**502**	**2,174**	**1,917**	**2,820**	**2,419**
International							
Australia		-	-	104	40	104	40
Total International		**-**	**-**	**104**	**40**	**104**	**40**
Total		**5,515**	**4,587**	**7,485**	**6,377**	**13,000**	**10,964**

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.
(7) Undeveloped acreage refers to those acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Exploration and Development Activities

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
2011											
Canadian Division	30	19	-	-	-	-	30	19	31	61	19
USA Division	19	6	3	3	-	-	22	9	5	27	9
Total	**49**	**25**	**3**	**3**	**-**	**-**	**52**	**28**	**36**	**88**	**28**
2010											
Canadian Division	22	15	-	-	-	-	22	15	31	53	15
USA Division	34	15	-	-	2	2	36	17	-	36	17
Total	**56**	**30**	**-**	**-**	**2**	**2**	**58**	**32**	**31**	**89**	**32**
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
Total	**42**	**28**	**5**	**5**	**1**	**-**	**48**	**33**	**33**	**81**	**33**

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) Results prior to November 30, 2009 include wells drilled on Canadian upstream properties transferred to Cenovus as part of the 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
2011 [3]											
Canadian Division	725	706	2	2	-	-	727	708	221	948	708
USA Division	695	392	-	-	5	1	700	393	206	906	393
Total	**1,420**	**1,098**	**2**	**2**	**5**	**1**	**1,427**	**1,101**	**427**	**1,854**	**1,101**
2010											
Canadian Division	1,270	1,190	1	1	-	-	1,271	1,191	203	1,474	1,191
USA Division	748	428	-	-	4	3	752	431	144	896	431
Total	**2,018**	**1,618**	**1**	**1**	**4**	**3**	**2,023**	**1,622**	**347**	**2,370**	**1,622**
2009											
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**

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, 2011, Encana was in the process of drilling the following exploratory and development wells: approximately 19 gross wells (17 net wells) in Canada and approximately 89 gross wells (52 net wells) in the U.S.

(4) Results prior to November 30, 2009 include wells drilled on Canadian upstream properties transferred to Cenovus as part of the Split Transaction.

Production Volumes (After Royalties)

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

Production Volumes (After Royalties)

(average daily)	2011 Annual	2011 Q4	2011 Q3	2011 Q2	2011 Q1
Produced Gas *(MMcf/d)*					
Canadian Division	1,454	1,515	1,460	1,445	1,395
USA Division	1,879	1,944	1,905	1,864	1,801
	3,333	**3,459**	**3,365**	**3,309**	**3,196**
Oil & NGLs *(Mbbls/d)*					
Canadian Division	14.5	13.9	15.1	14.8	14.3
USA Division	9.5	10.0	9.3	9.5	9.0
	24.0	**23.9**	**24.4**	**24.3**	**23.3**

(average daily)	2010	2009
Produced Gas *(MMcf/d)*		
Canadian Division	1,323	1,224
USA Division	1,861	1,616
	3,184	2,840
Canada – Other [(1)]	-	762
Total Produced Gas	**3,184**	**3,602**
Oil & NGLs *(Mbbls/d)*		
Canadian Division	13.2	15.9
USA Division	9.6	11.3
	22.8	27.2
Canada – Other [(1)]	-	99.9
Total Oil & NGLs	**22.8**	**127.1**

Notes:

(1) Results prior to November 30, 2009 include production from operations of the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Per-Unit Results (After Royalties)

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

Netbacks by Country (After Royalties)

	2011				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *($/Mcf)*					
Canadian Division					
Price, after royalties	3.79	3.44	3.89	3.97	3.87
Production and mineral taxes	0.02	0.02	0.02	0.02	0.02
Transportation	0.46	0.47	0.47	0.47	0.43
Operating	1.11	1.06	0.99	1.13	1.28
	2.20	1.89	2.41	2.35	2.14
USA Division					
Price, after royalties	4.47	3.95	4.64	4.76	4.56
Production and mineral taxes	0.23	0.20	0.21	0.25	0.26
Transportation	1.06	1.01	1.03	1.15	1.06
Operating	0.62	0.59	0.53	0.59	0.77
	2.56	2.15	2.87	2.77	2.47
Total Canadian & USA Divisions					
Price, after royalties	4.17	3.73	4.32	4.42	4.26
Production and mineral taxes	0.14	0.12	0.13	0.15	0.16
Transportation	0.80	0.77	0.79	0.85	0.79
Operating	0.83	0.80	0.73	0.82	0.99
	2.40	**2.04**	**2.67**	**2.60**	**2.32**
Oil & NGLs *($/bbl)*					
Canadian Division					
Price, after royalties	85.41	86.52	84.05	92.10	78.73
Production and mineral taxes	0.90	1.23	0.64	0.62	1.14
Transportation	0.93	0.68	1.15	1.16	0.69
Operating	1.75	2.00	1.35	1.65	2.03
	81.83	82.61	80.91	88.67	74.87
USA Division					
Price, after royalties	85.28	83.93	79.81	93.53	83.81
Production and mineral taxes	7.54	6.98	5.85	9.38	8.00
Transportation	0.08	0.24	0.08	-	-
Operating	0.70	2.04	0.61	-	-
	76.96	74.67	73.27	84.15	75.81
Total Canadian & USA Divisions					
Price, after royalties	85.36	85.44	82.43	92.66	80.70
Production and mineral taxes	3.52	3.64	2.63	4.03	3.80
Transportation	0.60	0.49	0.74	0.71	0.42
Operating	1.34	2.01	1.07	1.01	1.24
	79.90	**79.30**	**77.99**	**86.91**	**75.24**

Netbacks by Country
(After Royalties)

	Annual Average	
	2010	**2009** [1]
Produced Gas *($/Mcf)*		
Canada [2]		
Price, after royalties	4.10	3.64
Production and mineral taxes	0.01	0.04
Transportation	0.40	0.26
Operating	1.09	0.98
	2.60	2.36
United States		
Price, after royalties	4.73	3.75
Production and mineral taxes	0.27	0.17
Transportation	0.97	0.90
Operating	0.58	0.55
	2.91	2.13
Total Encana [1]		
Price, after royalties	4.47	3.69
Production and mineral taxes	0.16	0.10
Transportation	0.73	0.55
Operating	0.79	0.79
	2.79	**2.25**
Oil & NGLs *($/bbl)*		
Canada [2]		
Price, after royalties	64.79	49.75
Production and mineral taxes	0.44	0.63
Transportation	0.82	1.53
Operating	3.24	9.21
	60.29	38.38
United States		
Price, after royalties	69.35	48.56
Production and mineral taxes	6.69	4.39
Transportation	-	-
Operating	-	-
	62.66	44.17
Total Encana [1]		
Price, after royalties	66.72	49.65
Production and mineral taxes	3.08	0.97
Transportation	0.47	1.39
Operating	1.87	8.39
	61.30	**38.90**

Note:

(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.

(2) Results prior to November 30, 2009 include production from operations of the Canadian upstream assets that 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 Netbacks

	2011				
	Annual	Q4	Q3	Q2	Q1
Canadian Division					
Natural Gas *($/Mcf)*	0.69	0.93	0.57	0.59	0.64
USA Division					
Natural Gas *($/Mcf)*	0.87	1.15	0.78	0.73	0.81
Total Encana					
Natural Gas *($/Mcf)*	0.79	1.06	0.69	0.67	0.74

	Annual Average	
	2010	2009 (1)
Canada (2)		
Natural Gas *($/Mcf)*	0.99	3.25
Oil & NGLs *($/bbl)*	(1.04)	0.91
United States		
Natural Gas *($/Mcf)*	1.03	3.41
Total Encana (2)		
Natural Gas *($/Mcf)*	1.01	3.33
Oil & NGLs *($/bbl)*	(0.60)	0.83

Notes:

(1) As Encana's IFRS transition date was January 1, 2010, the Company's 2009 results are based on previous GAAP.

(2) Results prior to November 30, 2009 include production from operations of the Canadian upstream assets that were transferred to Cenovus as part of the Split Transaction.

Appendix E - Audit Committee Mandate

Last updated December 8, 2009. Last reviewed December 6, 2011.

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.