Encana Corporation

Annual Information Form
March 3, 2015

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Introduction

This is the Annual Information Form of **Encana Corporation** ("Encana" or the "Company") for the year ended December 31, 2014. 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.

The following volumetric measures may be abbreviated throughout this Annual Information Form: thousand cubic feet ("Mcf"); million cubic feet ("MMcf") per day ("MMcf/d"); billion cubic feet ("Bcf"); trillion cubic feet ("Tcf"); barrel ("bbl"); thousand barrels ("Mbbls") per day ("Mbbls/d"); million barrels ("MMbbls"); barrels of oil equivalent ("BOE") per day ("BOE/d"); thousand barrels of oil equivalent ("MBOE") per day ("MBOE/d"); million barrels of oil equivalent ("MMBOE") per day ("MMBOE/d"); and million British thermal units ("MMBtu").

Certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of 6:1 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 natural gas as compared to oil 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.

The term "liquids" is used to represent oil, natural gas liquids ("NGLs") and condensate. The term "liquids rich" is used to represent natural gas streams with associated liquids volumes.

All financial information included in this Annual Information Form is prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP"). The Company's annual audited Consolidated Financial Statements for the year ended December 31, 2014, including required comparative information for 2013 and 2012, have been prepared in accordance with U.S. GAAP.

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

This Annual Information Form is available via the System for Electronic Documentation Analysis and Retrieval ("SEDAR") at www.sedar.com and the Electronic Data Gathering, Analysis and Retrieval System ("EDGAR") at www.sec.gov.

Unless otherwise specified, all dollar amounts are expressed in U.S. dollars, all references to "dollars", "$" or "US$" are to U.S. dollars and all references to "C$" are to Canadian dollars. All amounts are provided on a before tax basis, unless otherwise stated.

Corporate Structure

Name and Incorporation

Encana Corporation is incorporated under the *Canada Business Corporations Act* ("CBCA"). Its executive and registered office is located at 4400, 500 Centre Street S.E., Calgary, Alberta, Canada T2P 2S5.

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, 2014. 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, 2014.

Subsidiaries & Partnerships	Percentage Directly or Indirectly Owned	Jurisdiction of Incorporation, Continuance or Formation
Encana USA Holdings ULC	100	Alberta
1847432 Alberta ULC	100	Alberta
Alenco Holdings Inc.	100	Delaware
Alenco Inc.	100	Delaware
Encana Oil & Gas (USA) Inc.	100	Delaware
Athlon Energy Inc.	100	Delaware
Athlon Holdings LP	100	Delaware
Encana Marketing (USA) Inc.	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, 2014, respectively.

As a general matter, Encana reorganizes its subsidiaries and partnerships 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 a corporate reorganization (the "Split Transaction") to split into two independent publicly traded energy companies – Encana and Cenovus Energy Inc. ("Cenovus").

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

Operating Segments

As at December 31, 2014, Encana's operating and reportable segments were: (i) Canadian Operations; (ii) USA Operations; and (iii) Market Optimization.

- **Canadian Operations** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within Canada. Plays in Canada include: Montney in northern British Columbia and northwest Alberta; Duvernay in west central Alberta; and Other Upstream Operations including Clearwater in central and southern Alberta, Deep Panuke located offshore Nova Scotia and Other and emerging. Other and emerging primarily includes Cadomin/Doig in northeast British Columbia, Horn River in northeast British Columbia and Granite Wash/Doig in northwest Alberta.

- **USA Operations** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S. Plays in the U.S. include: Eagle Ford in south Texas; Permian in west Texas; DJ Basin in northern Colorado; San Juan in northwest New Mexico; and Other Upstream Operations including Piceance in northwest Colorado, Haynesville in northwest Louisiana and Other and emerging. Other and emerging primarily includes Tuscaloosa Marine Shale in east Louisiana and west Mississippi.

- **Market Optimization** activities are managed by the Midstream, Marketing & Fundamentals team, which is primarily responsible for the sale of the Company's proprietary production and enhancing the associated netback price. 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.

Corporate and Other is not an operating segment and mainly includes unrealized gains or losses recorded on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recorded 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:

2014

- Completed the acquisition of all of the issued and outstanding shares of common stock of Athlon Energy Inc. ("Athlon") for $5.93 billion, or $58.50 per share, assumed Athlon's $1.15 billion senior notes, and repaid and terminated Athlon's credit facility with indebtedness outstanding of $0.3 billion. The acquisition includes approximately 137,000 net acres of producing and undeveloped oil and gas properties in the Permian Basin ("Permian") located in west Texas (primarily in the Midland, Martin, Howard and Glasscock counties). Following completion of the acquisition, Athlon's $1.15 billion senior notes were redeemed in accordance with the provisions of the indentures governing such senior notes.

  Additional information relating to the acquisition of Athlon is included in the Company's business acquisition report dated January 23, 2015, which is available via SEDAR at www.sedar.com and EDGAR at www.sec.gov.

- Completed the initial public offering of 59.8 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") at a price of C$28.00 per common share for aggregate gross proceeds of approximately C$1.67 billion. Subsequent to the initial public offering, Encana owned 70.2 million common shares of PrairieSky, representing a 54 percent ownership interest.

  In the third quarter, Encana completed a secondary offering of the remaining 70.2 million common shares of PrairieSky at a price of C$36.50 per common share for aggregate gross proceeds of approximately C$2.6 billion. Following the completion of the secondary offering, Encana no longer holds an interest in PrairieSky.

- Completed the acquisition of certain properties in the Eagle Ford shale formation ("Eagle Ford") located in south Texas from Freeport-McMoRan Oil & Gas LLC and PXP Producing Company LLC for approximately $2.9 billion, after closing adjustments. The acquisition includes approximately 45,500 net acres of producing and undeveloped oil and gas properties located in the Karnes, Wilson and Atascosa counties.

  Additional information relating to the acquisition of Eagle Ford is included in the Company's business acquisition report dated June 20, 2014, which is available via SEDAR at www.sedar.com and EDGAR at www.sec.gov.

- Completed the divestiture of properties in Jonah located in Wyoming for proceeds of approximately $1.6 billion after closing adjustments and certain properties in East Texas for proceeds of approximately $495 million after closing adjustments.

- Completed the sale of properties in Bighorn located in west central Alberta for approximately $1.7 billion after closing adjustments.

- Entered into an agreement to sell certain properties in Clearwater located in central and southern Alberta, including Encana's working interest in approximately 1.2 million net acres of land. The sale closed on January 15, 2015 and proceeds of approximately C$556 million after closing adjustments were received.

- Entered into an agreement with Veresen Midstream Limited Partnership under which Encana and Cutbank Ridge Partnership, a partnership between Encana and a subsidiary of Mitsubishi Corporation ("Mitsubishi"), agreed to sell certain natural gas gathering and compression assets in the Montney area for approximately C$412 million in cash consideration net to Encana. The transaction is expected to close in the first quarter of 2015 subject to regulatory approval and completion of closing conditions.

2013

- Appointed Doug Suttles as Encana's President & Chief Executive Officer and Director of the Company in June 2013 and subsequently announced a realignment of the Company's business strategy and corporate organizational structure in November 2013, which was implemented in 2014.
- Commenced production at the Deep Panuke natural gas facility located offshore Nova Scotia in August 2013 and reached commercial operation with the issuance of the Production Acceptance Notice in December 2013.
- Completed the divestiture of assets in the Canadian Operations for proceeds of approximately $685 million which primarily included the sale of the Jean Marie natural gas assets in the Greater Sierra play.
- Completed the sale of Encana's 30 percent interest in the proposed Kitimat liquefied natural gas export terminal in British Columbia in February 2013.

2012

- Entered into a partnership agreement with Mitsubishi to jointly develop certain lands in northeast British Columbia. Mitsubishi agreed to invest approximately C$2.9 billion for a 40 percent interest in the partnership, with C$1.45 billion received in February 2012. The remaining amount is expected to be invested based on the five year development plan of the area.
- Entered into an agreement with a PetroChina Company Limited subsidiary ("PetroChina") to jointly explore and develop certain Duvernay lands located in west central Alberta. PetroChina agreed to invest approximately C$2.18 billion for a 49.9 percent working interest in the lands with C$1.18 billion received in December 2012. The remaining amount will be received over an expected commitment period which expires in 2020.
- Entered into an agreement with a Toyota Tsusho Corporation subsidiary ("Toyota Tsusho") under which Toyota Tsusho agreed to acquire a royalty interest in natural gas production from a portion of Encana's Clearwater play. Toyota Tsusho agreed to invest approximately C$600 million for a 32.5 percent gross overriding royalty, with C$100 million received in April 2012. The remaining amount will be received over the expected commitment period of approximately seven years, which runs through to 2019.
- Entered into a long-term joint venture agreement with a Nucor Corporation subsidiary ("Nucor"), under which Nucor will earn a 50 percent working interest in certain natural gas wells to be drilled over the term of the agreement in the Piceance Basin located in Colorado. Nucor agreed to pay its share of well costs plus a portion attributable to Encana's interest.
- Closed the sale of two natural gas processing plants in British Columbia and Alberta for proceeds of approximately C$920 million in February 2012.

Narrative Description of the Business

The following map outlines the location of Encana's North American landholdings, plays and emerging plays as at December 31, 2014.

Business Objectives

Encana's operations are focused on exploiting strategic, high return and scalable natural gas and oil formations. The Company's operations are primarily located in Canada and the U.S. All of Encana's reserves and production are located in North America.

Encana is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. The Company's key objectives include:

- Balancing the commodity portfolio
- Exercising a disciplined capital allocation strategy
- Maintaining portfolio flexibility to respond to changing market conditions
- Maximizing profitability through operational efficiency and reducing costs
- Preserving balance sheet strength

The Company has a history of identifying and entering into strategic prospective plays and leveraging technology to unlock resources and build the underlying productive capacity at a low cost. Encana continually strives to improve operating efficiencies, foster technological innovation and lower its cost structures. The Company's resource play hub model is a manufacturing-style development approach, which utilizes integrated production facilities to develop resources by drilling multiple wells from central pad sites. Capital and operating efficiencies are achieved across Encana's diverse portfolio through repeatable operations, optimizing equipment and processes and by applying continuous improvement techniques.

Encana's capital investment strategy is focused on accelerating growth from a limited number of strategic, high return and scalable projects, while optimizing production performance from the remainder of the Company's resource base.

Canadian Operations

The Canadian Operations includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within Canada. Plays in Canada include: Montney in northern British Columbia and northwest Alberta; Duvernay in west central Alberta; and Other Upstream Operations including Clearwater in central and southern Alberta, Deep Panuke located offshore Nova Scotia and Other and emerging. Other and emerging includes: Cadomin/Doig in northeast British Columbia, Horn River in northeast British Columbia and Granite Wash/Doig in northwest Alberta. Other Upstream Operations comprises plays that are not part of Encana's strategic focus as well as prospective plays which are under appraisal.

In 2014, certain plays were reorganized to align with the Company's business objectives, as described in the "Business Objectives" section of this Annual Information Form. Accordingly, comparative information has been reorganized. Montney and Duvernay reflect Encana's focus on the future growth and development in those plays. Montney comprises the Montney formations that were formerly held in Cutbank Ridge and Peace River Arch. Duvernay was formerly presented in Other and emerging. Other and emerging primarily includes: the remaining properties previously held in Cutbank Ridge, which was renamed Cadomin/Doig; Greater Sierra, which was renamed Horn River; and the remaining properties previously held in Peace River Arch, which was renamed Granite Wash/Doig.

In the second quarter of 2014, Encana transferred ownership of its royalty business, which comprised fee simple mineral title and certain royalty interests in lands formerly held within the Clearwater play into a separate company, PrairieSky, and subsequently completed an initial public offering of 59.8 million common shares of PrairieSky for gross proceeds of approximately C$1.67 billion. In the third quarter of 2014, Encana completed a secondary offering of the remaining 70.2 million common shares of PrairieSky for gross proceeds of approximately C$2.6 billion. Following the completion of the secondary offering, Encana no longer holds an interest in PrairieSky.

In the third quarter of 2014, Encana divested of Bighorn for proceeds of approximately $1.7 billion, which included approximately 360,000 net acres, along with Encana's working interests in pipelines, facilities and service arrangements. These divestitures are further described in the "Recent Developments" section of this Annual Information Form.

In 2014, the Canadian Operations had total capital investment of approximately $1,226 million and drilled approximately 279 net wells. Production after royalties averaged approximately 1,378 MMcf/d of natural gas, approximately 13.6 Mbbls/d of oil, and approximately 23.6 Mbbls/d of NGLs. At December 31, 2014, the Canadian Operations had an established land position in Canada of approximately 5.6 million gross acres (4.1 million net acres) including approximately 2.8 million gross undeveloped acres (2.0 million net undeveloped acres).

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

Landholdings

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
(thousands of acres at December 31, 2014)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Montney	309	211	574	395	883	606	69%
Duvernay	71	27	633	385	704	412	59%
Other Upstream Operations							
Clearwater	2,094	1,740	737	570	2,831	2,310	82%
Deep Panuke	20	20	21	10	41	30	73%
Other and emerging	323	165	830	614	1,153	779	68%
Total Canadian Operations	**2,817**	**2,163**	**2,795**	**1,974**	**5,612**	**4,137**	**74%**

Producing Wells

	Natural Gas		Oil		Total	
(number of wells at December 31, 2014) [1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Montney	779	717	67	59	846	776
Duvernay	13	7	8	2	21	9
Other Upstream Operations						
Clearwater	11,751	11,057	154	138	11,905	11,195
Deep Panuke	4	4	-	-	4	4
Other and emerging	616	503	2	2	618	505
Total Canadian Operations	**13,163**	**12,288**	**231**	**201**	**13,394**	**12,489**

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

Production (Before Royalties)

(average daily)	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Oil (Mbbls/d) 2014	Oil (Mbbls/d) 2013	NGLs (Mbbls/d) 2014	NGLs (Mbbls/d) 2013
Montney	576	490	6.8	3.4	15.1	8.1
Duvernay	11	4	0.8	0.6	1.4	0.2
Other Upstream Operations						
Clearwater (1)	333	374	7.0	7.8	2.0	2.4
Bighorn (1)	166	256	0.4	0.6	8.2	9.7
Deep Panuke	196	42	-	-	-	-
Other and emerging (2)	229	344	0.2	0.2	0.1	0.9
Total Canadian Operations	**1,511**	**1,510**	**15.2**	**12.6**	**26.8**	**21.3**

Notes:
(1) During 2014, Encana divested its Bighorn play and investment in PrairieSky.
(2) During 2013, Encana divested its Jean Marie natural gas assets in Horn River.

Production (After Royalties)

(average daily)	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Oil (Mbbls/d) 2014	Oil (Mbbls/d) 2013	NGLs (Mbbls/d) 2014	NGLs (Mbbls/d) 2013
Montney	514	463	5.5	3.0	13.2	7.0
Duvernay	11	4	0.8	0.5	1.3	0.2
Other Upstream Operations						
Clearwater (1)	292	335	6.8	7.7	1.8	2.2
Bighorn (1)	158	255	0.3	0.5	7.2	8.4
Deep Panuke	190	41	-	-	-	-
Other and emerging (2)	213	334	0.2	0.2	0.1	0.7
Total Canadian Operations	**1,378**	**1,432**	**13.6**	**11.9**	**23.6**	**18.5**

Notes:
(1) During 2014, Encana divested its Bighorn play and investment in PrairieSky.
(2) During 2013, Encana divested its Jean Marie natural gas assets in Horn River.

Plays and Other Activities in the Canadian Operations

Montney

Montney is a play located in the Canadian Rocky Mountain foothills, which extends from southwest of Dawson Creek, in northern British Columbia to northwest Alberta. Montney is being exclusively 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 2014, Encana drilled approximately 79 net wells in the area and production after royalties averaged approximately 514 MMcf/d of natural gas and approximately 18.7 Mbbls/d of oil and NGLs.

At December 31, 2014, Encana controlled approximately 574,000 gross undeveloped acres (395,000 net undeveloped acres) covering the deep basin Montney formation. Since the first horizontal well completion in the area in 2006, Encana has continued to apply advanced technologies to reduce the overall development costs by approximately 75 percent on a completed interval basis. During 2014, Encana focused on drilling longer wells with an average effective length of approximately 8,700 feet and tighter completion spacing at approximately 80 feet per perforation.

Encana has a partnership agreement with Mitsubishi to jointly develop certain lands predominately in the Montney. Under the agreement, Mitsubishi agreed to invest approximately C$2.9 billion for its 40 percent partnership interest, of which to date approximately C$2.0 billion has been received as of December 31, 2014. In addition to its 40 percent of the partnership's future capital funding investment, Mitsubishi is required to invest the remaining amount of approximately C$0.9 billion over the five year development plan of the area, thereby reducing Encana's capital funding commitment to 30 percent of the total expected capital investment over that development plan. Encana proportionately consolidates 60 percent interest in the partnership, including reserves.

As at December 31, 2014, Encana has natural gas processing capacity of approximately 700 MMcf/d with eight plants located in Alberta and British Columbia under contract with third parties with commitment terms ranging from three to 17 years. The plant capacities range from 100 MMcf/d to 225 MMcf/d of which Encana has approximately 90 MMcf/d of processing capacity at the Gordondale sour gas deep cut plant, which has averaged net liquids production of approximately 6.0 Mbbls/d after royalties. Of the total processing capacity under contract, approximately 260 MMcf/d is used to process Encana's net share of natural gas for the partnership with Mitsubishi. Encana also has gathering and compression capacity of 161 MMcf/d under a remaining 19 year commitment with a third party in the Pipestone/Sexsmith area.

In addition to the contracted capacity, Encana owns natural gas processing capacity of approximately 175 MMcf/d at three plants located in Alberta, with plant capacities ranging from 115 MMcf/d to 210 MMcf/d, of which Encana holds an approximate 60 percent ownership interest in the Sexsmith plant that has total capacity of approximately 210 MMcf/d (net 125 MMcf/d to Encana).

Duvernay

Duvernay is a play located in west central Alberta and includes properties that are primarily located in the Duvernay formation. The focus of development is on exploiting shale gas and condensate in the Duvernay formation. In 2014, Encana commenced pad drilling in the northern part of the play, which is being developed with horizontal well technology. Encana is currently achieving significant improvements in drilling costs and cycle times through application of its resource play hub model and continuing to develop long-term take-away capacity. In 2014, Encana drilled approximately 24 net wells in the area and production after royalties averaged approximately 11 MMcf/d of natural gas and approximately 2.1 Mbbls/d of oil and NGLs. At December 31, 2014, Encana controlled approximately 563,000 gross undeveloped acres (345,000 net undeveloped acres) in the Duvernay formation.

Encana has an agreement with PetroChina to jointly explore and develop certain Duvernay lands. Under the agreement, PetroChina agreed to invest approximately C$2.18 billion for a 49.9 percent working interest in the lands. PetroChina has invested approximately C$1.59 billion to date and is to further invest approximately C$590 million over the remaining commitment period that expires in 2020, which will be used to fund half of Encana's capital commitment.

Encana holds an approximate 50.1 percent ownership in two Simonette gas plants with a combined natural gas processing capacity of 55 MMcf/d (net 28 MMcf/d to Encana) and NGLs production capacity of 10 Mbbls/d (net 5.0 Mbbls/d to Encana).

Other Upstream Operations

Clearwater

Clearwater is a play located predominantly in central and southern Alberta and includes both natural gas and oil resources. Natural gas development has focused on the Horseshoe Canyon coals which are integrated with shallower sands. Encana is using an integrated wellbore strategy to exploit deeper targets within the formation. In 2014, Encana drilled approximately 174 net natural gas wells. Production after royalties averaged approximately 292 MMcf/d of natural gas and approximately 8.6 Mbbls/d of oil and NGLs. At December 31, 2014, Encana controlled approximately 737,000 gross undeveloped acres (570,000 net undeveloped acres) in the play.

During 2014, Encana divested its royalty business comprising approximately 6.3 million gross acres of fee simple mineral title and 0.5 million gross acres of certain royalty interests, for aggregate gross proceeds of approximately C$4.27 billion in two separate offerings of common shares of PrairieSky held by Encana. On January 15, 2015, Encana completed the sale of certain working interests in properties in Clearwater to Ember Resources Inc. for C$556 million after closing adjustments. The sale comprised approximately 1.4 million gross acres (1.2 million net acres) and contained over 6,800 producing wells. In 2014, the production associated with these wells averaged approximately 172 MMcf/d of natural gas and approximately 0.3 Mbbls/d of oil and NGLs. Collectively, the divestiture of the royalty business to PrairieSky and the sale of certain working interests to Ember Resources

Inc. constituted a substantial portion of the acreage in Clearwater. See the "Recent Developments" section of this Annual Information Form.

Subsequent to the divestitures, Encana has retained a working interest in approximately 1.4 million gross acres (1.1 million net acres) with approximately 537,000 gross undeveloped acres (419,000 net undeveloped acres) primarily in the Wheatland area of southern Alberta. Development is focused along the eastern edge of the Horseshoe Canyon Fairway with approximately 479,000 gross acres (466,000 net acres). In 2014, production after royalties associated with the retained acreage averaged approximately 97 MMcf/d of natural gas and approximately 2.4 Mbbls/d of oil and NGLs. To align with Encana's retained acreage in the area, Clearwater is expected to be renamed Wheatland in 2015.

Encana has an agreement with Toyota Tsusho under which Toyota Tsusho will acquire a 32.5 percent gross overriding royalty interest in natural gas production from a portion of Encana's Clearwater play. Toyota Tsusho has invested C$277 million to date and is required to further invest approximately C$325 million over the remaining five year commitment period.

Deep Panuke

Encana is the owner and operator of the Deep Panuke gas field located offshore Nova Scotia, which is approximately 250 kilometres southeast of Halifax on the Scotian shelf. Natural gas from Deep Panuke is produced and processed by an offshore Production Field Centre ("PFC") which is designed to process up to 300 MMcf/d from four wells. The PFC is under a lease arrangement which has an initial term that expires in 2021, with the option to extend the lease for 12 successive one-year terms at fixed prices after the initial lease term. Produced gas is transported to Goldboro, Nova Scotia, via subsea pipeline which interconnects with the Maritimes & Northeast Pipeline, where the natural gas is ultimately transported to markets in eastern Canada and the northeast U.S. The PFC commenced commercial operations in December 2013.

In 2014, natural gas production after royalties averaged approximately 190 MMcf/d. Encana sells all natural gas produced from Deep Panuke under a long term physical sales contract at the prevailing market prices in that region. At December 31, 2014, Encana controlled approximately 41,000 gross acres (30,000 net acres) in Nova Scotia. Encana operates five of its six licenses in these areas.

Other Activity

Cadomin/Doig is located in northeast British Columbia. In 2014, Encana's natural gas production after royalties averaged 94 MMcf/d. At December 31, 2014, Encana controlled approximately 212,000 gross undeveloped acres (115,000 net undeveloped acres). Production is gathered and processed using the same facilities located in Montney.

Horn River is located in northeast British Columbia. The focus of development has been in the Horn River Basin shales (Muskwa, Otter Park and Evie), which are upwards of 500 feet thick. In 2014, Encana's natural gas production after royalties averaged approximately 83 MMcf/d. At December 31, 2014, Encana held within the development area of the Horn River Basin shales approximately 99 gross producing horizontal wells (50 net producing horizontal wells). At December 31, 2014, Encana controlled approximately 183,000 gross undeveloped acres (159,000 net undeveloped acres) in the Horn River Basin shales. Encana owns natural gas compression capacity in Horn River of approximately 570 MMcf/d (net 285 MMcf/d to Encana) at various facilities in the area. Encana has a processing commitment with a third party related to a planned expansion of the Cabin natural gas processing plant, for which commissioning and expansion was suspended in 2012.

Granite Wash/Doig is located in northwest Alberta. In 2014, Encana's production after royalties averaged approximately 31 MMcf/d of natural gas and 0.2 Mbbls/d of oil and NGLs. At December 31, 2014, Encana controlled approximately 175,000 gross undeveloped acres (162,000 net undeveloped acres) in the formation. Production is gathered and processed using the same facilities located in Montney.

USA Operations

The USA Operations includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S. Plays in the U.S. include: Eagle Ford in south Texas; Permian in west Texas; DJ Basin in northern Colorado; San Juan in northwest New Mexico; and Other Upstream Operations including Piceance in northwest Colorado, Haynesville in northwest Louisiana and Other and emerging. Other and emerging primarily includes Tuscaloosa Marine Shale in east Louisiana and west Mississippi. Other Upstream Operations comprises certain plays that are not part of Encana's strategic focus as well as emerging prospective plays which are under appraisal, such as Tuscaloosa Marine Shale.

In 2014, certain plays were reorganized to align with the Company's business strategy, as described in the "Business Objectives" section of this Annual Information Form. Accordingly, comparative information has been reorganized. DJ Basin and San Juan have been reorganized to reflect the Company's focus on the future growth and development of those plays. DJ Basin, previously named DJ Niobrara, and San Juan were formerly presented in Other and emerging. Piceance and Haynesville are included in Other Upstream Operations.

During 2014, Encana divested of approximately 121,000 net acres in Jonah for proceeds of approximately $1.6 billion after closing adjustments and approximately 91,000 net acres in East Texas for proceeds of approximately $495 million after closing adjustments, as described in the "Recent Developments" section of this Annual Information Form.

In 2014, Encana acquired properties in two new plays including approximately 45,500 net acres in Eagle Ford in south Texas for approximately $2.9 billion after closing adjustments, and approximately 137,000 net acres in Permian in west Texas through the acquisition of Athlon, as described in the "Recent Developments" section of this Annual Information Form. The acquisitions are strategic oil weighted plays and complement the Company's business strategy.

In 2014, the USA Operations had total capital investment of approximately $1,285 million and drilled approximately 204 net wells. Production after royalties averaged approximately 972 MMcf/d of natural gas, approximately 35.8 Mbbls/d of oil, and approximately 13.8 Mbbls/d of NGLs. At December 31, 2014, the USA Operations had an established land position of approximately 2.3 million gross acres (1.8 million net acres) including approximately 1.5 million gross undeveloped acres (1.2 million net undeveloped acres).

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

Landholdings

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
(thousands of acres at December 31, 2014)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Eagle Ford	39	39	6	6	45	45	100%
Permian	86	85	54	52	140	137	98%
DJ Basin	46	43	9	9	55	52	95%
San Juan	50	31	303	175	353	206	58%
Other Upstream Operations							
Piceance	275	257	525	485	800	742	93%
Haynesville	179	101	91	62	270	163	60%
Other and emerging	66	50	533	382	599	432	72%
Total USA Operations	**741**	**606**	**1,521**	**1,171**	**2,262**	**1,777**	**79%**

Producing Wells

(number of wells at December 31, 2014) [1]	Natural Gas Gross	Natural Gas Net	Oil Gross	Oil Net	Total Gross	Total Net
Eagle Ford	-	-	327	314	327	314
Permian	-	-	1,199	1,116	1,199	1,116
DJ Basin	1,527	900	-	-	1,527	900
San Juan	161	55	172	140	333	195
Other Upstream Operations						
Piceance	3,495	2,793	-	-	3,495	2,793
Haynesville	561	278	-	-	561	278
Other and emerging	406	309	56	30	462	339
Total USA Operations	**6,150**	**4,335**	**1,754**	**1,600**	**7,904**	**5,935**

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

Production (Before Royalties)

(average daily)	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Oil (Mbbls/d) 2014	Oil (Mbbls/d) 2013	NGLs (Mbbls/d) 2014	NGLs (Mbbls/d) 2013
Eagle Ford	25	-	21.8	-	3.5	-
Permian	6	-	3.2	-	1.2	-
DJ Basin	52	47	9.0	6.0	5.1	4.3
San Juan	10	3	4.1	1.4	0.8	0.3
Other Upstream Operations						
Piceance	474	533	1.9	2.0	3.8	3.9
Haynesville	391	436	-	-	-	-
Jonah [1]	128	415	1.4	4.2	0.9	1.9
East Texas [1]	75	180	0.7	1.2	-	-
Other and emerging	33	51	2.8	2.4	1.4	1.2
Total USA Operations	**1,194**	**1,665**	**44.9**	**17.2**	**16.7**	**11.6**

Note:
(1) During 2014, Encana divested the Jonah and the East Texas plays.

Production (After Royalties)

(average daily)	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Oil (Mbbls/d) 2014	Oil (Mbbls/d) 2013	NGLs (Mbbls/d) 2014	NGLs (Mbbls/d) 2013
Eagle Ford	19	-	17.1	-	2.7	-
Permian	5	-	2.5	-	1.0	-
DJ Basin	43	39	7.4	4.9	4.2	3.5
San Juan	8	3	3.3	1.2	0.6	0.2
Other Upstream Operations						
Piceance	402	455	1.6	1.8	3.4	3.3
Haynesville	311	348	-	-	-	-
Jonah [1]	100	323	1.1	3.3	0.7	1.4
East Texas [1]	57	136	0.5	1.0	-	-
Other and emerging	27	41	2.3	1.7	1.2	1.2
Total USA Operations	**972**	**1,345**	**35.8**	**13.9**	**13.8**	**9.6**

Note:
(1) During 2014, Encana divested the Jonah and the East Texas plays.

Plays and Other Activities in the USA Operations

Eagle Ford

On June 20, 2014, Encana acquired certain properties in the Eagle Ford shale formation located in south Texas in the Karnes, Wilson and Atascosa counties. Eagle Ford is a tight oil play with the focus on development of the thickest portion of the Eagle Ford shale in the Karnes Trough, where Encana holds a largely contiguous position. From June 20, 2014 to December 31, 2014, production after royalties averaged approximately 32.0 Mbbls/d of oil, approximately 36 MMcf/d of natural gas and approximately 5.1 Mbbls/d of NGLs. During 2014, the Company completed an acreage swap, whereby Encana was released from certain third party joint development obligations, thereby increasing the Company's working interest and allowing Encana to operate and control the pace of development throughout its acreage. At December 31, 2014, Encana controlled approximately 45,000 net acres.

Encana is developing the play using horizontal wells with lateral lengths averaging 5,000 feet at an average measured depth of 16,000 feet, based on a 30 to 40 acre down spacing. Encana has been actively optimizing well design and improving drilling costs through its resource play hub model. Since June 2014, Encana has reduced drilling costs by approximately 10 percent. At December 31, 2014, Encana has 314 net producing horizontal wells, of which Encana has drilled 35 net horizontal wells since acquiring the properties.

Oil production is gathered at 32 central production facilities, with the majority of the oil subsequently transported to sales points by pipeline or trucked from facilities depending on the sales contract. Encana has dedicated approximately 26 MMcf/d to 60 MMcf/d of natural gas under a remaining commitment term of up to six years for gathering and processing capacity.

Permian

On November 13, 2014, Encana acquired certain properties in the Permian through the acquisition of Athlon. Permian is located in west Texas in Midland, Martin, Howard and Glasscock counties. The focus is on the development of the Clearfork, Spraberry, Wolfcamp, Cline, Strawn, Atoka and Mississippian formations, in the Midland basin, where Encana holds a large contiguous position. The properties are characterized by an extensive production history from vertical drilling and development and mature infrastructure, with multiple producing horizons spanning over 3,000 feet to 4,000 feet of stratigraphy (also referred to as "stacked pay zones"). The multiple stacked pay zones can accommodate multiple completions in a single wellbore with the potential for both vertical and horizontal drilling. From November 13, 2014 to December 31, 2014, production after royalties averaged approximately 18.6 Mbbls/d of oil, approximately 37 MMcf/d of natural gas and approximately 7.6 Mbbls/d of NGLs. At December 31, 2014, Encana controlled approximately 137,000 net acres.

With exposure to 11 potential productive horizons, Encana intends to focus future development primarily with horizontal wells using multi-well pad development. Since acquiring the asset in 2014, Encana has drilled 7 net horizontal wells with lateral lengths averaging approximately 7,700 feet at a measured average depth of approximately 16,600 feet and completed drilling 21 net vertical wells. At December 31, 2014, Encana has 1,092 net producing vertical wells and 24 net producing horizontal wells.

Oil and natural gas facilities located at well locations include field gathering systems, storage batteries, saltwater disposal systems, separation equipment and pumping units. In addition, the play has an established pipeline infrastructure to transport oil from wellhead to tank batteries which is subsequently transported by the purchaser via pipeline or truck. Natural gas is transported from wellhead to the purchaser's meter and pipeline interconnection point through Encana's gathering system.

DJ Basin

DJ Basin is a liquids rich play located in northern Colorado. The focus is on the development of the Codell, J-Sand and the Niobrara of the Wattenberg field. In 2014, Encana drilled approximately 64 net horizontal wells with an average effective length of 5,300 feet. Encana is pilot testing various well spacing and completion combinations in order to maximize resource recovery and minimize the development footprint. In 2014, production after royalties averaged approximately 43 MMcf/d of natural gas, approximately 7.4 Mbbls/d of oil and approximately 4.2 Mbbls/d of NGLs. At December 31, 2014, Encana controlled approximately 9,000 gross undeveloped acres (8,500 net undeveloped acres).

Encana has certain joint venture agreements whereby its partner earns a 50 percent working interest in certain natural gas wells to be drilled at Encana's discretion in the DJ Basin. The joint venture partner will pay its share of costs plus an additional carry amount for wells drilled, which is determined with reference to certain benchmark prices and the nature of the well drilled. The commitment has a remaining term of 11 years with potential additional five one-year extensions thereafter. Either party can elect to suspend drilling for natural gas wells in event natural gas or oil benchmark prices fall below a specified threshold. To date, Encana has received $224 million under the terms of the agreements. In 2014, third party funds were primarily used to drill all 64 net horizontal wells.

Encana has dedicated natural gas production under a commitment with a third party for processing. The third party's total plant capacity is approximately 625 MMcf/d. Encana is currently constructing a central liquids gathering facility near Erie, Colorado that is anticipated to have approximately 22.0 Mbbls/d of capacity. Construction is expected to be completed in the latter half of 2016.

San Juan

San Juan is a light sweet oil play located in the San Juan Basin in northwest New Mexico. The primary formation targets in the basin are the Gallup sandstone and Mancos silt. Encana has established a significant land position in the play and continues to delineate the acreage held. In 2014, production after royalties averaged approximately 3.3 Mbbls/d of oil, approximately 8 MMcf/d of natural gas and approximately 0.6 Mbbls/d of NGLs. At December 31, 2014, Encana controlled approximately 303,000 gross undeveloped acres (175,000 net undeveloped acres). Encana currently has an average rig count of two and drilled approximately 43 net horizontal wells in 2014, with effective lateral lengths ranging from 3,800 to 7,300 feet and an average vertical depth of 5,300 feet.

Other Upstream Operations

Piceance

Piceance is a 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 also focused in the Niobrara and Mancos formations, which are thick shales predominant throughout the basin. In 2014, production after royalties averaged approximately 402 MMcf/d of natural gas, approximately 1.6 Mbbls/d of oil and approximately 3.4 Mbbls/d of NGLs. At December 31, 2014, Encana controlled approximately 525,000 gross undeveloped acres (485,000 net undeveloped acres). In 2014, Encana drilled one net well in the play.

Encana has a long-term joint venture agreement with Nucor under which Nucor will earn a 50 percent working interest in certain natural gas wells to be drilled in Piceance. Under the terms of the agreement, Nucor will carry Encana for approximately $750 million, of which Encana has received approximately $24 million as of December 31, 2014. Nucor will further invest the remaining amount over the remaining long-term commitment period. The joint venture partner will pay its share of costs plus an additional carry amount for wells drilled, which is based on pre-determined percentage allocations partially indexed to natural gas prices. It also contains certain limitations on the minimum and maximum number of wells that may be drilled in any calendar year over the duration of the agreement. Either party may suspend drilling operations if the average price of natural gas falls below a pre-determined threshold but neither party has a unilateral right to terminate the agreement. Since December 2013, Encana and Nucor jointly agreed to suspend drilling natural gas wells due to the current weak natural gas price environment.

In addition, Encana has other existing joint venture arrangements to develop portions of the Piceance. To date, Encana has drilled approximately 271 net wells under the agreements, primarily using third party funds. The pace of development is determined in accordance with the joint venture agreements.

Encana has current gathering capacity of approximately 276 MMcf/d under commitments with third parties with remaining terms up to 12 years. Encana has contracted processing capacity up to 650 MMcf/d with a third party, with no volume commitment.

Haynesville

The Haynesville shale is a play located in northwest Louisiana. The focus is on maximizing gas recovery in the Haynesville and Mid-Bossier horizons. Encana has developed the lands using a multi-well pad approach in key areas. In 2014, Encana focused on production optimization by completing a 12 well re-stimulation program and compression implementation. Production after royalties averaged approximately 311 MMcf/d of natural gas. At December 31, 2014, Encana controlled approximately 91,000 gross undeveloped acres (62,000 net undeveloped acres), with the majority of the leaseholds in northwest Louisiana being located in the DeSoto and Red River parishes.

Encana has current natural gas gathering and compression capacity in Haynesville of approximately 826 MMcf/d under a commitment through 2020.

Other Activity

The Tuscaloosa Marine Shale is an emerging oil play located in east Louisiana and west Mississippi and currently under appraisal. Encana has established a significant land position in the play and is focused on maximizing oil recovery in the Tuscaloosa Marine Shale formation. In 2014, Encana drilled approximately 14 net horizontal wells with an average effective lateral length of 6,800 feet. Production after royalties averaged approximately 1.8 Mbbls/d of oil. At December 31, 2014, Encana controlled approximately 322,000 gross undeveloped acres (201,000 net undeveloped acres).

Market Optimization

Market Optimization activities are managed by Encana's Midstream, Marketing & Fundamentals team, which is responsible for the sale of the Company's proprietary production and enhancing the associated netback price. 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.

Encana's produced natural gas and NGLs are primarily marketed to local distribution companies, industrials, other producers, energy marketing companies and midstream companies. Prices received by Encana are based primarily upon prevailing index prices in the region in which it is sold. Prices are impacted by regional supply and demand for natural gas and NGLs and by competing fuels in such markets.

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, less than 12 months in duration, at the relevant market price at the time the product is sold. Encana sells all natural gas produced from Deep Panuke under a long term physical sales contract at prevailing market prices in that region. As at December 31, 2014, Encana had no material long term fixed price physical sales contracts or delivery contracts.

Encana's produced oil is primarily marketed to other producers and energy marketing companies. Produced oil is transported primarily by the purchaser to sales points by pipeline or trucked from facilities depending on the sales contract. Prices received by Encana are based primarily upon the prevailing index prices in the relevant region under contract terms that range from one to four years.

Encana seeks to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced natural gas, oil and NGLs and power. Details of those contracts related to Encana's various risk management positions are found in Note 23 to Encana's audited Consolidated Financial Statements for the year ended December 31, 2014, which are available via SEDAR at www.sedar.com and EDGAR at www.sec.gov.

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 historical 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;
- 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; and
- the Canadian standards require that proved undeveloped reserves be reviewed annually for retention or reclassification if development has not proceeded as previously planned, while the U.S. standards specify a five year limit after initial booking for the development of proved undeveloped reserves.

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 NGLs reserves annually. In 2014, 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 Cawley, Gillespie & Associates, Inc.

Encana's Chief, Reservoir Engineering and six other staff under this individual's direction oversee the preparation of the reserves estimates by the IQREs. This internal staff consisted of engineers, six of whom have professional designations, with a combined relevant experience of over 100 years. The engineering staff were all members of the appropriate professional associations as well as being members of various industry associations such as the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Encana has a Reserves Committee composed of independent board members that reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the IQREs. 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. All locations to which proved undeveloped reserves have been assigned are subject to a development plan adopted by Encana's management.

Acquisitions, Divestitures and Capital Investment

Encana has a large inventory of internal growth opportunities and also continues to examine select acquisition opportunities to develop and expand its 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 2014 and 2013.

($ millions)	2014	2013
Capital Investment		
Canadian Operations	1,226	1,365
USA Operations	1,285	1,283
Market Optimization	-	3
Corporate & Other	15	61
	2,526	2,712
Acquisitions		
Canadian Operations	21	28
USA Operations	2,995	156
Divestitures		
Canadian Operations	(1,847)	(685)
USA Operations	(2,264)	(18)
Market Optimization	(205)	-
Corporate & Other	(29)	(2)
Net Acquisitions and (Divestitures)	(1,329)	(521)
Net Capital Investment	**1,197**	**2,191**

Capital investment during 2014 reflected the Company's disciplined capital spending which focused on investment in high return scalable projects and opportunities where development has demonstrated success, as well as executing drilling programs with joint venture partners. Acquisitions in the Canadian Operations of $21 million primarily included land and property purchases with oil and liquids rich production potential. Acquisitions in the USA Operations of $2,995 million primarily related to the acquisition of properties in the Eagle Ford shale in south Texas for $2.9 billion, which is predominately an oil-weighted play.

Divestiture proceeds for 2014 in the Canadian Operations of $1,847 million primarily included the sale of the Bighorn properties in west central Alberta for approximately $1,725 million. Divestiture proceeds in the USA Operations of $2,264 million primarily included the sale of properties in Jonah in Wyoming and certain properties in East Texas for aggregate proceeds of $2,131 million. For additional information on acquisitions and divestitures, see the "Recent Developments" section of this Annual Information Form.

Other Transactions

The following transactions relate to the acquisition or disposition of common shares and are therefore excluded from the net capital investment table above.

On November 13, 2014, Encana acquired all of the issued and outstanding shares of common stock of Athlon for $5.93 billion, or $58.50 per share, as described in the "Recent Developments" section of this Annual Information Form. The properties acquired through the acquisition of Athlon are located in the Permian Basin in west Texas, which is an oil-weighted play.

During 2014, Encana divested its royalty business, comprising fee simple mineral title and certain royalty interests, for a total of approximately C$4.27 billion in two separate offerings of common shares of PrairieSky held by Encana. During the second quarter of 2014, the initial public offering of 59.8 million common shares of PrairieSky for C$28.00 per common share was completed for proceeds of approximately C$1.67 billion. During the third quarter of 2014, the secondary offering of the remaining 70.2 million common shares of PrairieSky for C$36.50 per common share was completed for proceeds of approximately C$2.6 billion.

Competitive Conditions

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

- Exploration for and development of new sources of natural gas, oil and NGLs reserves;
- Reserves and property acquisitions;
- Transportation and marketing of natural gas, oil, NGLs and diluents;
- 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 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 business plans with a current price range from approximately $20 to $125 per tonne of emissions, applied to a range of emissions coverage levels. Encana's forecast cost of carbon associated with British Columbia and Alberta regulations is not material to Encana and is being actively managed.

Encana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2014, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material. Encana's current estimate of the total undiscounted future abandonment and reclamation costs to be incurred over the life of the reserves is approximately $3.6 billion. As at December 31, 2014, Encana has recorded an asset retirement obligation of $913 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; engage, listen to and work with stakeholders in a timely, respectful and meaningful way; and align 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 Policy provides all personnel working on an Encana location with the authority and responsibility to stop work without repercussions when an unsafe situation is recognized or suspected.

The Policies and any revisions are approved by Encana's Executive Leadership Team and its Board of Directors. Accountability for implementation of the Policies is at the operational level within Encana's organizational structure. The operating teams have established processes to evaluate risks and programs have been implemented to minimize those risks. Coordination and oversight of the Policies resides with Encana's Policy, Environment and Sustainability group.

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 members of Encana's Board of Directors and the Company's employees;
- An Environmental, Health & Safety ("EH&S") management system and internal corporate audit program that evaluates Encana's compliance with the expectations and requirements of the 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;

- 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 of up to $25,000 per employee, per year;
- An Investigations Practice and an internal Ethics and Compliance team to receive, investigate and resolve complaints regarding potential violations of Encana policies or practices and/or the law;
- 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;
- A Business Code of Conduct which establishes Encana's commitment to conducting business ethically and legally and to which employees, contractors and directors are held accountable; and
- Related policies and practices such as an Anti-Fraud Policy, a Conflict of Interest Policy, a Prevention of Corruption Policy, an Alcohol and Drug Policy, a Political Contributions Policy, an Information Management Policy, an Acceptance of Gifts Practice and a Lobbying Practice which outline Encana's expectations of employee, contractor and director behaviors that are 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, 2014, Encana employed 3,129 employees as set forth in the following table.

	Employees
Canada	1,707
U.S.	1,422
Total	**3,129**

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

Foreign Operations

As at December 31, 2014, 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
Clayton H. Woitas [5,7] Calgary, Alberta, Canada	2008	Chairman Encana Corporation
Peter A. Dea [3,5,6] Denver, Colorado, U.S.A.	2010	President & Chief Executive Officer Cirque Resources LP (Private oil & gas company)
Fred J. Fowler [3,4] Houston, Texas, U.S.A.	2010	Corporate Director
Howard J. Mayson [3,5,6] Breckenridge, Colorado, U.S.A.	2014	Corporate Director
Lee A. McIntire [3,4] Denver, Colorado, U.S.A.	2014	Corporate Director
Suzanne P. Nimocks [2,4,5] Houston, Texas, U.S.A.	2010	Corporate Director
Jane L. Peverett [2,5,6] West Vancouver, British Columbia, Canada	2003	Corporate Director
Brian G. Shaw [2,6] Toronto, Ontario, Canada	2013	Corporate Director
Douglas J. Suttles [8] Calgary, Alberta, Canada	2013	President & Chief Executive Officer Encana Corporation
Bruce G. Waterman [2,4] Calgary, Alberta, Canada	2010	Corporate Director

Notes:
(1) Denotes the year each individual became a director of Encana.
(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. Woitas 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. Suttles is not a member of any Board Committees.

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

At the date of this Annual Information Form, there are 10 directors of the Company. All of the current directors were elected at the last annual meeting of shareholders held on May 13, 2014, except for Howard J. Mayson, who was appointed by the Board of Directors effective June 2, 2014, and Lee A. McIntire, who was appointed by the Board of Directors effective December 1, 2014. At the next annual meeting, shareholders will be asked to elect as directors each of the individuals listed in the above table. 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
Douglas J. Suttles Calgary, Alberta, Canada	President & Chief Executive Officer
Joanne L. Alexander Calgary, Alberta, Canada	Executive Vice-President & General Counsel
Sherri A. Brillon Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
David G. Hill Denver, Colorado, U.S.A.	Executive Vice-President, Exploration & Business Development
Michael G. McAllister Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer
D. Ryder McRitchie Calgary, Alberta, Canada	Vice-President, Investor Relations & Communications
Michael Williams Calgary, Alberta, Canada	Executive Vice-President, Corporate Services
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:

Mr. Suttles joined Encana in June 2013. From March 2011 until June 2013, he was an independent businessman performing consulting services in the oil and gas industry and serving on the boards of Ceres, Inc. (a publicly traded energy crop company) and NEOS GeoSolutions (a privately held geosciences company). Mr. Suttles was Chief Operating Officer at BP Exploration & Production from January 2009 until March 2011.

Mr. Fowler is a director of Spectra Energy Partners, LP (a public entity). He was Chairman of Spectra Energy Partners, LP from October 2008 until November 2013. 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.

Mr. Mayson is a director of Corex Resources Ltd., Endurance Energy Ltd., Hawkwood Energy LLC and Fairfield Energy Ltd. and serves on the Advisory Board for the private equity firm Kern Partners. He has over 35 years of oil and gas industry experience, primarily with BP Exploration & Production where he held various senior roles including Chief Executive Officer of BP Russia, President BP Angola, Director of BP's Exploration & Production Technology Group and headed up BP's Global Subsurface Function.

Mr. McIntire served as President and Chief Executive Officer of CH2M HILL (a private consulting company) from January 2009 to January 2014, Chairman from 2010 through 2014, and served as the Executive Chairman of the Board of Directors of CH2M HILL from January 2014 to October 2014. Mr. McIntire was a director of BAE Systems (British Aerospace) PLC (a public global defence, aerospace and security company) from June 2011 to August 2013.

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.

Mr. Shaw has been a director of NuVista Energy Ltd. (a public oil and gas company) since August 2014, Manulife Bank of Canada (a private chartered bank) since February 2012 and Manulife Trust Company (a private trust company) since February 2012. Prior to that, Mr. Shaw was Chairman and Chief Executive Officer of CIBC World Markets Inc. from 2005 through 2008.

Mr. Waterman was Executive Vice President, International Development of Agrium Inc. (a public agricultural supply company) from February 2012 through January 2013. From April 2011 through February 2012, Mr. Waterman was Executive Vice President and Chief Strategy Development & Investment Officer of Agrium and from April 2000 through April 2011 he was Senior Vice President, Finance & Chief Financial Officer of Agrium.

Mr. Woitas is Chairman of the Board of Encana Corporation and acted as Interim President & Chief Executive Officer of Encana from January 2013 until June 2013. He was Chairman & Chief Executive Officer of Range Royalty Management Ltd. (a private oil and gas royalty company) from 2005 to December 2014.

Ms. Alexander was Senior Vice President, General Counsel and Corporate Secretary of Precision Drilling Corporation (a public oil and gas services company) from April 2008 to December 2014 and General Counsel of Marathon Oil Canada Corporation from 2007 to 2008.

Mr. Williams was Executive Vice President of Corporate Services with Tervita Corporation (a private energy services company) from 2011 to 2014 and Chief Administration Officer for TransAlta Corporation (a public power company) from 2002 to 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 24, 2015, an aggregate of 297,610 common shares representing 0.04 percent of the issued and outstanding voting shares of Encana, and held options to acquire an aggregate of 3,063,036 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 four 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.

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, Associated Electric & Gas Insurance Services Limited (a private mutual insurance company), Postmedia Network Canada Corp. and Postmedia Network Inc. (a public publishing company). She is also the Audit Committee Chair of Canadian Imperial Bank of Commerce. 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 18-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.

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 plc (a public international contract drilling services company), ArcelorMittal (a public international steel company) and Owens Corning (a global producer of residential and commercial building materials). 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.

Brian G. Shaw

Mr. Shaw is a Chartered Financial Analyst, holds a Masters of Business Administration (University of Alberta) and a Bachelor of Commerce (University of Alberta) and is a Corporate Director. Mr. Shaw is a director of NuVista Energy Ltd. (a public oil and gas company), Manulife Bank of Canada (a private chartered bank), Manulife Trust Company (a private trust company) and Ivey Canadian Exploration Ltd. (a private exploration company). He is Chairman of the Risk Committee of Manulife Bank of Canada and also Manulife Trust Company. Mr. Shaw was a director of PrairieSky Royalty Ltd. from April 2014 until December 2014. He has experience in corporate finance, capital markets, investing activities and corporate governance gained through his executive level position at CIBC World Markets Inc., which included his role as Chairman and Chief Executive Officer of CIBC World Markets Inc. from 2005 through 2008.

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). Mr. Waterman is a director of Enbridge Income Fund Holdings Inc. and a trustee of Enbridge Commercial Trust. He is also a director of Irving Oil Limited and Prairie Storm Energy Corp. He was Executive Vice President of Agrium Inc. (a public agricultural company), where he held senior roles as Chief Financial Officer, as well as in Business Development and Strategy, from April 2000 through to his retirement in January 2013. 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 was a director of PrairieSky Royalty Ltd. from April 2014 until December 2014. 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 and as a result of serving as Talisman's Chief Financial Officer for over four years (as noted above). At Amoco (a global chemical, oil and gas company which merged with British Petroleum in 1998), his roles included various positions in finance, accounting and business development.

The above list does not include Clayton H. Woitas 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 2014 and 2013.

(C$ thousands)	**2014**	**2013**
Audit Fees [(1)]	3,303	3,583
Audit-Related Fees [(2)]	877	312
Tax Fees [(3)]	940	415
All Other Fees[(4)]	4	4
Total	**5,124**	**4,314**

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 2014 and 2013, the services provided in this category included reviews in connection with acquisitions and divestitures, research of accounting and audit-related issues and the review of reserves disclosure.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2014 and 2013, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.

(4) During fiscal 2014 and 2013, 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.

Encana did not rely on the *de minimis* exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of Securities and Exchange Commission ("SEC") Regulation S-X in 2014 or 2013.

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 at December 31, 2014, there were approximately 741.2 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 plan are generally fully exercisable between three to four years. Options granted under the plans prior to February 24, 2015 will expire five years after the grant date. Subject to shareholder approval at the Company's 2015 annual meeting of shareholders, options granted under the plans on or subsequent to February 24, 2015 will expire seven years after the grant date.

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 reconfirmed at the Company's 2013 annual 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. Each of the first preferred shares and second preferred shares are subject to a limitation on issue such that the Company may not issue any shares of such class if by so doing the aggregate amount payable to the holders of the applicable class as a return of capital in the event of liquidation, dissolution or winding up of the Company or any other distribution of the assets of the Company among its shareholders for the purpose of winding up its affairs would exceed C$500 million.

On February 24, 2015, the Board of Directors authorized amendments to the Company's articles to redesignate the Company's existing first and second preferred shares into a single class of preferred shares to be designated as "Class A Preferred Shares". The Class A Preferred Shares will be similar to the existing preferred shares in terms of their priority over the common shares of the Company and the fact that they may be issued in one or more series as determined by the Board of Directors from time to time; however, they will have additional restrictions, including that the Class A Preferred Shares will be non-voting except in certain limited circumstances and will only be convertible into another series of Class A Preferred Shares (and not common shares of the Company). In addition, the proposed terms of Class A Preferred Shares provide that the number of Class A Preferred Shares which may be issued and outstanding at any time shall be limited to a number equal to not more than twenty percent of the number of issued and outstanding common shares of the Company at the time of issuance of any Class A Preferred Shares.

In order to become effective, the amendments to the Company's articles must be approved by a special resolution of the holders of the Company's common shares. The Company intends to seek shareholder approval at the Company's 2015 annual meeting of shareholders whereby the special resolution must be passed by not less than 66⅔ percent of the votes cast in respect of the special resolution.

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 transactions for risk management activities.

The following table outlines the ratings issued by the respective rating agencies as of February 24, 2015.

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

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality. 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 commitments. S&P's short-term commercial paper ratings are on a scale that ranges from A-1+ to C, which represents the range from highest to lowest quality. A rating of A-2 is the fourth highest of seven categories and indicates satisfactory capacity of the obligor to fulfill its financial commitment on the obligation, while exhibiting higher susceptibility to changing circumstances or economic conditions than obligators rated A-1.

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 judged to be medium grade and subject to moderate credit risk. As such, they 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 BBB by DBRS is within the fourth highest of ten categories and is assigned to obligations considered to be of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable. 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-2 (mid) is the fifth highest of ten categories and indicates that the short-term debt is of adequate credit quality. The capacity for the payment of short-term financial obligations as they fall due is acceptable and the issuer may be vulnerable to future events or may be exposed to other factors that could reduce credit quality.

Encana has paid each of S&P, Moody's and DBRS their customary fees in connection with the provision of the above ratings. Encana has also made payments to S&P, Moody's and DBRS over the past two years for subscriptions to use their online credit analytical tools.

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 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 2014.

	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)
2014								
January	20.59	18.52	20.02	48.6	18.60	17.18	17.97	12.5
February	21.75	19.55	21.00	56.4	19.63	17.61	18.98	17.2
March	23.87	20.90	23.61	47.6	21.59	18.89	21.38	17.8
April	26.16	23.21	25.39	47.0	23.85	21.10	23.21	17.8
May	26.08	24.32	25.25	48.5	23.93	22.36	23.31	19.1
June	26.85	25.09	25.28	39.6	24.83	22.95	23.71	13.6
July	25.17	22.78	23.48	41.9	23.96	21.23	21.55	16.4
August	25.07	22.78	25.07	28.5	23.05	20.77	23.03	12.9
September	25.69	23.05	23.78	48.1	23.40	20.72	21.21	18.0
October	24.41	19.58	21.00	60.5	21.74	17.41	18.63	30.2
November	21.84	18.02	18.02	41.8	19.30	15.76	15.78	23.7
December	18.38	13.31	16.17	80.3	16.15	11.45	13.87	37.2

Encana’s Dividend Reinvestment Plan (“DRIP”) permits the Company to issue to participating shareholders Encana common shares at a discount, as determined by the Board of Directors from time to time, to the average market price for the applicable dividend payment date. On February 25, 2015, Encana announced that any future dividends of common shares distributed to shareholders participating in the DRIP will be issued from Encana’s treasury at a two percent discount to the average market price of common shares (as defined in the DRIP) unless otherwise announced by Encana via news release. During 2014, common shares distributed to participating shareholders pursuant to the DRIP were issued from Encana’s treasury without a discount to the average market price.

Dividends

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2014 Encana paid a quarterly dividend of $0.07 per share ($0.28 per share annually). In 2013 Encana paid a quarterly dividend of $0.20 for the first three quarters and $0.07 for the fourth quarter ($0.67 per share annually). In 2012, Encana paid a quarterly dividend of $0.20 per share ($0.80 per share annually).

Legal Proceedings

Encana is involved in various legal claims and actions arising in the course of the Company's operations. Although the outcome of these matters cannot be predicted with certainty and there can be no assurance that such matters will be resolved in Encana's favour, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined.

See "Risk Factors – The Company is subject to claims, litigation, administrative proceedings and regulatory actions".

Risk Factors

If any event arising from the risk factors set forth below occurs, Encana's business, prospects, financial condition, results of operations, cash flows or the trading prices of securities 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, environmental, regulatory, reputational and safety aspects of the identified risk factor.

A substantial or extended decline in natural gas, oil or NGLs prices and price differentials could have a material adverse effect on Encana.

Encana's financial performance and condition are substantially dependent on the prevailing prices of natural gas, oil or NGLs. Fluctuations in natural gas, oil or NGLs prices and significant North American and Canadian price differentials 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, oil or NGLs fluctuate in response to changes in the supply and demand for natural gas, oil or NGLs, 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, and renewable energy initiatives). Oil prices are largely determined by international and domestic 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 and domestic supply of oil, the price of foreign imports, the availability of alternate fuel sources, transportation and infrastructure constraints and weather conditions. Historically, NGLs prices have generally been correlated with oil prices, and are determined based on supply and demand in international and domestic NGLs markets.

A substantial or extended decline in the price of natural gas, oil or NGLs, or a continued low price environment for natural gas, oil or NGLs 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.

Natural gas and oil producers in North America, and particularly in Canada, currently receive discounted prices for their production relative to certain international prices due to constraints on their ability to transport and sell such production to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by natural gas and oil producers, including Encana.

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, oil or NGLs 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, reliance on industry partners and service providers, unexpected cost increases, royalties, taxes, volatility in natural gas, oil or NGLs 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. In addition, some of these risks may be magnified due to the concentrated nature of funding certain assets within the Company's portfolio of oil and natural gas properties that are operated within limited geographic areas. As a result, a number of the Company's assets could experience any of the same risks and conditions at the same time, resulting in a relatively greater impact on the Company's financial condition and results of operations than they might have on other companies that have a more geographically diversified portfolio of properties.

Declines in natural gas, oil or NGLs prices create fiscal challenges for the oil and gas industry. These conditions impact companies in the oil and gas industry and may alter the Company's spending and operating plans. There may be unexpected business impacts from market uncertainty, including volatile changes in currency exchange rates, inflation, interest rates, defaults of suppliers 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.

Encana's reserves data and future net revenue estimates are uncertain.

There are numerous uncertainties inherent in estimating quantities of natural gas, oil and NGLs 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 NGLs 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 NGLs 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.

Furthermore, estimates with respect to the reserves to be developed and produced in the future are based upon certain expectations and assumptions, including the allocation of capital, which may be subject to change.

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 NGLs 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. In addition, part of Encana's strategy is focused on a limited number of strategic growth assets which results in a concentration of capital and potential risks. To the extent that cash flows from the Company's 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 NGLs reserves and production 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.

The Company's business is subject to environmental regulation in all jurisdictions in which it operates and any changes in such regulation could negatively affect its results of operations.

All phases of the natural gas, oil or NGLs 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 regulation").

Environmental regulation 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 regulation 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 regulation can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties and failure to comply with environmental regulation may result in the imposition of fines and penalties.

Although it is not expected that the costs of complying with environmental regulation 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 regulation 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 U.S. federal government has noted climate change action as a priority for the current administration. On January 14, 2015, the U.S. Environmental Protection Agency ("EPA") outlined a series of steps to address methane and volatile organic compound emissions from the oil and gas industry, including a new goal to reduce oil and gas methane emissions by 40 percent to 45 percent from 2012 levels by 2025. The reductions will be achieved through yet to be announced regulatory and voluntary measures. The EPA plans to propose this new rule and guidance in late summer 2015 with a final rule and guidance expected in 2016. The Canadian federal government has announced that it will align greenhouse gas emission reduction targets with the U.S. The Canadian federal government has taken a sector-specific approach, and while progress has been made working with industry and the provinces on the development of oil and gas sector-specific regulations, the Canadian federal government has not committed to a definitive timeline for the implementation or release of legislation. 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 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 the state of Colorado, several cities have passed local ordinances limiting or banning certain oil and gas activities, including hydraulic fracturing. These local rule-making initiatives have not significantly impacted the Company's operations or development plans in the state to date. The ballot initiatives previously filed in the state seeking to transfer the authority to regulate all oil and gas activities, including hydraulic fracturing, to local governments were withdrawn in 2014. Encana continues to work with state and local governments, academics and industry leaders to develop and respond to hydraulic fracturing related concerns in Colorado. The Company recognizes that additional hydraulic fracturing ballot initiatives and/or local rule making limiting or restricting oil and gas development activities are a possibility in the future and will continue to monitor and respond to these developments in 2015.

Further, certain governments in jurisdictions where the Company does not currently operate have considered or implemented moratoriums 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 or curtailment of production in order to comply with legislation governing emissions and hydraulic fracturing.

Encana may not realize anticipated benefits or be subject to unknown risks from acquisitions.

Encana has completed a number of acquisitions in order to strengthen its position and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

Acquiring oil and natural gas properties requires the Company to assess reservoir and infrastructure characteristics, including estimated recoverable reserves, future production, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities. Although the acquired properties are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired properties are in geographic areas where the Company has not historically operated. Further, the Company also may not be able to obtain or realize upon contractual indemnities from the seller for liabilities created prior to an acquisition and it may be required to assume the risk of the physical condition of the properties that may not perform in accordance with its expectations.

Encana is subject to risks associated with joint ventures and partnerships.

Some of Encana's projects are conducted through joint ventures, partnerships or other arrangements, where Encana is dependent on its partners to fund their contractual share of the capital and operating expenditures related to such projects. If these partners do not approve or are unable to fund their contractual share of certain capital or operating expenditures or otherwise fulfill their obligations, this may result in project delays or additional future costs to Encana, all of which may affect the viability of such projects.

These partners may also have strategic plans, objectives and interests that do not coincide with and may conflict with those of Encana. While certain operational decisions may be made solely at the discretion of Encana in its capacity as operator of certain projects, major capital and strategic decisions affecting such projects may require agreement among the partners. While Encana and its partners generally seek consensus with respect to major decisions concerning the direction and operation of the project assets, no assurance can be provided that the future demands or expectations of any party, including Encana, relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet such demands or expectations may affect Encana's or its partners' participation in the operation of such assets or the timing for undertaking various activities, which could negatively affect Encana's operations and financial results.

The Company may be unable to dispose of certain assets on attractive terms, or at all, and may be required to retain liabilities for certain matters.

The Company may identify certain assets, the disposition of which could increase capital available for other activities or reduce the Company's existing indebtedness. Various factors could materially affect the Company's ability to dispose of those assets or complete announced transactions including current commodity prices, the availability of purchasers willing to purchase certain assets at prices and on terms acceptable to the Company, approval by Encana's Board of Directors, due diligence, favourable market conditions and stock exchange, regulatory and third party approvals.

The Company may also retain certain liabilities for certain matters in a sale transaction. The magnitude of any such retained liabilities or indemnification obligations may be difficult to quantify at the time of the transaction and could ultimately be material. Further, certain third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after the sale of certain assets, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the purchaser of the assets fails to perform its obligations.

The Company's level of indebtedness may limit its financial flexibility.

As of December 31, 2014, the Company had total long-term debt of $7,340 million, which includes a $1,277 million outstanding balance under its revolving credit facilities. The terms of the Company's various financing arrangements, including but not limited to the indentures relating to its outstanding senior notes and its revolving credit facilities, impose restrictions on its ability and, in some cases, the ability of the Company's subsidiaries, to take a number of actions that it or they may otherwise desire to take, including (i) incurring additional debt, including guarantees of indebtedness; (ii) creating liens on the Company's or its subsidiaries assets; and (iii) selling certain of the Company's or its subsidiaries' assets.

The Company's level of indebtedness could affect its operations by:

- requiring it to dedicate a portion of cash flows from operations to service its indebtedness, thereby reducing the availability of cash flow for other purposes;
- reducing its competitiveness compared to similar companies that have less debt;
- limiting its ability to obtain additional future financing for working capital, capital investments and acquisitions;
- limiting its flexibility in planning for, or reacting to, changes in its business and industry; and
- increasing its vulnerability to general adverse economic and industry conditions.

The Company's ability to meet its debt obligations and service those debt obligations depends on future performance. General economic conditions, natural gas, oil or NGLs prices, and financial, business and other factors affect the Company's operations and future performance. Many of these factors are beyond the

Company's control. If the Company is unable to satisfy its obligations with cash on hand, the Company could attempt to refinance debt or repay debt with proceeds from a public offering of securities or selling certain assets. No assurance can be given that the Company will be able to generate sufficient cash flow to pay the interest obligations on its debt, or that funds from future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance its debt, or on terms that will be favourable to the Company. Further, future acquisitions may decrease the Company's liquidity by using a significant portion of its available cash or borrowing capacity to finance such acquisitions, and such acquisitions could result in a significant increase in the Company's interest expense or financial leverage if it incurs additional debt to finance such acquisitions.

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's risk management 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, oil or NGLs prices.

Under U.S. GAAP, derivative instruments that do not qualify or are not designated as hedges for accounting purposes 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 if the Company is unable to produce natural gas, oil or NGLs, or if counterparties to the Company's hedging agreements fail to fulfill their obligations under the hedging agreements, particularly during periods of declining commodity prices.

Encana's operations are subject to the risk of business interruption and casualty losses. Our insurance may not fully protect us against these risks and liabilities.

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.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations. A breach in the Company's security measures or a loss of its material and confidential information could result in a disruption to its business activities or competitive position. The significance of any such event is difficult to quantify, but may in certain circumstances have a material adverse effect on the Company's business or results of operations.

We maintain insurance against some, but not all, of these risks and losses. 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.

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's liquidity may also be impacted if any lender under the Company's existing credit facilities is unable to fund its commitment. 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.

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. 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 revenue and 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.

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 is subject to claims, litigation, administrative proceedings and regulatory actions.

Encana may be subject to claims, litigation, administrative proceedings and regulatory actions. The outcome of these matters may be difficult to assess or quantify, and there cannot be any assurance that such matters will be resolved in the Company's favour. If Encana is unable to resolve such matters favourably, the Company or its directors, officers or employees may become involved in legal proceedings that could result in an onerous or unfavourable decision, including fines, sanctions and monetary damages. The defence of such matters may also be costly and time consuming, and could divert the attention of management and key personnel from the Company's operations. Encana may also be subject to adverse publicity associated with such matters, regardless of whether such allegations are valid or whether the Company is ultimately found liable. As a result, such matters could have a material adverse effect on the Company's reputation, financial position, results of operations or liquidity. See also "Legal Proceedings" in this Annual Information Form.

The Company relies on certain key personnel and the ability to attract and retain personnel necessary for its business.

The Company relies on certain key personnel for the development of its business. The experience, knowledge and contributions of the Company's existing management team and directors to the immediate and near-term operations and direction of the Company are likely to continue to be of central importance for the foreseeable future. As such, the loss of services from or retirement of such key personnel could have a material adverse effect on the Company. In addition, the competition for qualified personnel in the oil and gas industry is intense, and there can be no assurance that the Company will be able to continue to attract and retain such personnel with the required specialized skills necessary for its business.

The Company may be subject to future changes in laws.

Income tax laws, royalty regimes, environmental laws or other laws and regulations may in the future be changed or interpreted in a manner that adversely affects the Company or its securityholders. Tax authorities having jurisdiction over the Company or its shareholders could change their administrative practices, or may disagree with the manner in which the Company calculates its tax liabilities or structures its arrangements, to the detriment of the Company or its securityholders. Changes to existing laws and regulations or the adoption of new laws and regulations could also increase the Company's cost of compliance and adversely affect the Company's business, financial position, cash flows or results of operations.

Encana has certain indemnification obligations to certain counterparties.

Encana has agreed to indemnify or be indemnified by numerous counterparties for certain liabilities and obligations associated with businesses or assets retained or transferred by the Company. Specifically, 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 also has indemnification obligations under certain acquisition and divestiture activities it has undertaken, including the activities described in the "Recent Developments" section of this Annual Information Form.

Encana cannot determine whether it will be required to indemnify certain counterparties for any substantial obligations. Encana also cannot be assured that, if a counterparty is required to indemnify Encana and its affiliates for any substantial obligations, such counterparties will be able to satisfy such obligations. Any indemnification claim against Encana pursuant to the provisions of the transaction agreements could have a material adverse effect on Encana.

Transfer Agents and Registrars

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

In Canada:
CST Trust 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

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 website at: www.canstockta.com/en/InvestorServices/InvestorInquiryForm.

Interest of Experts

The Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated March 3, 2015 in respect of the Company's Consolidated Financial Statements as at December 31, 2014 and December 31, 2013, and for each of the years in the three year period ended December 31, 2014, and the Company's effectiveness of internal control over financial reporting as at December 31, 2014. 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 Cawley, Gillespie & Associates, Inc., 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 Cawley, Gillespie & Associates, Inc., 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, 2014.

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", "agreed to", "is to" 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 the Company's focus of developing its strong portfolio of diverse plays producing natural gas, oil and NGLs
- the expected timing and closing date of the Veresen Midstream Limited Partnership transaction and the expectation that regulatory approvals will be obtained and closing conditions satisfied
- anticipated future proceeds from various joint venture, partnership and other agreements entered into by the Company, including the successful implementation of and other expected benefits to be generated from those agreements
- the Company's commitment to growing long-term shareholder value through a disciplined focus on generating profitable growth
- the Company's plan to maximize profitability through operational efficiency, reducing costs, disciplined capital allocation and focused capital investment in strategic, high return scalable assets
- maintaining a balanced portfolio with flexibility to respond to changing market conditions
- anticipated cost reductions and the ability to preserve balance sheet strength
- anticipated cash flow
- anticipated access to capital markets and ability to meet financial obligations and finance growth
- the success of implementing the resource play hub strategy across certain plays
- expected accelerated growth from a limited number of high return projects while optimizing the Company's base production
- anticipated drilling and number of drilling rigs and the success thereof and anticipated production from wells and the product composition of such production
- anticipated drilling costs and cycle times
- anticipated oil, natural gas and NGLs prices
- expectation for risk management contracts to mitigate market risk associated with future cash flows
- estimated reserves and resources
- availability of large inventory of internal growth opportunities
- anticipated dividends
- amendments to the Company's articles and stock-based compensation plans
- 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 and the potential impact to the Company relating to air quality, water, land and hydraulic fracturing
- maintaining satisfactory credit ratings
- pending and potential litigation and having adequate provision for the same

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, oil or NGLs prices, including substantial or extended decline of the same and their adverse effect on the Company's operations and financial condition and the value and amount of its reserves
- assumptions based upon the Company's current guidance
- risks and uncertainties associated with announced but not completed transactions including the risk that the transactions may not be completed on a timely basis or at all
- fluctuations in currency and interest rates
- risk that the Company may not conclude divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) 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, oil or NGLs from 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
- risks associated with the Company's hedging activities including realized and unrealized losses and the Company's ability to enter into attractive hedges to protect the Company's capital program
- business interruption and casualty losses
- risks associated with 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
- potential variability of dividend payment amounts, and the continued future payment of dividends
- Encana's ability to generate sufficient cash flow from operations to meet its current and future obligations
- Encana's ability to access external sources of debt and equity capital
- 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
- risk arising from price basis differentials
- 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 NGLs 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 NGLs 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. The Canadian protocol disclosure is contained in ***Appendix A*** and under “Narrative Description of the Business”. Encana 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***.

Further, Encana obtained an exemption dated January 21, 2015 (the “2015 Exemption Order”) from certain requirements of NI 51-101, to permit it to use the definition of “product type” contained in the amendments to NI 51-101 published by the securities regulatory authority in each of the jurisdictions of Canada on December 4, 2014 that are anticipated to come into force on July 1, 2015, as it relates to its Canadian protocol disclosure contained in Appendix A.

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. Certain terms in this Annual Information Form relating to oil and gas reserves and operating activities have the meaning assigned to them in NI 51-101 or are otherwise defined in this Annual Information Form.

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

In this Appendix, except as described otherwise in this Annual Information Form, Encana provides disclosure of its reserves and oil and gas information in accordance with the requirements of NI 51-101 and the terms of the 2015 Exemption Order. 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, 2014 and was prepared as of February 23, 2015.

Since inception, Encana has retained IQREs to evaluate and prepare reports on 100 percent of Encana's natural gas, oil and NGLs 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 NGLs 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 some indirect costs 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 tables included in this Appendix refer to the following product types [(1):]

- **Shale Gas**, which includes Duvernay and Horn River in the Canadian Operations and Haynesville in the USA Operations. This product type also includes natural gas associated with tight oil in Permian, Eagle Ford and Tuscaloosa Marine Shale in the USA Operations.

- **Coalbed Methane**, which includes coalbed methane commingled with shallow gas sands, related to the Clearwater play in the Canadian Operations.

- **Conventional Gas**, which includes natural gas other than coalbed methane and shale gas. This product type includes the following plays: Montney, Deep Panuke, Cadomin/Doig and Granite Wash/Doig in the Canadian Operations; and DJ Basin and Piceance in the USA Operations. Excluding Deep Panuke, the formations being targeted in these plays are of low permeability and require fracking to produce commercial quantities of natural gas. This product type also includes natural gas associated with tight oil in San Juan in the USA Operations.

- **Tight Oil**, which includes Montney and Duvernay in the Canadian Operations and Eagle Ford, Permian, San Juan, DJ Basin and Tuscaloosa Marine Shale tight oil in the USA Operations. This product type also includes field condensate from the USA Operations.

- **Natural Gas Liquids**, which includes NGLs processed from natural gas production within the plays.

Note:

(1) On January 21, 2015, Encana obtained the 2015 Exemption Order with respect to product types which is further described in the "Note Regarding Reserves Data and Other Oil and Gas Information" section of this Annual Information Form. Comparative information has accordingly been reorganized.

Reserves Data (Canadian Protocol)

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

As at December 31, 2014

Canadian Operations

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	298	588	1,595	2,481	10.5	39.1	49.5
Developed non-producing	12	13	83	108	-	2.2	2.3
Undeveloped	73	100	991	1,163	3.6	41.8	45.4
Total Proved	383	701	2,668	3,752	14.0	83.1	97.2
Probable	180	191	2,158	2,529	5.1	72.4	77.5
Total Gross Proved Plus Probable	**563**	**891**	**4,826**	**6,280**	**19.1**	**155.5**	**174.6**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	586	-	1,248	1,834	128.1	61.0	189.1
Developed non-producing	11	-	43	55	14.3	6.0	20.3
Undeveloped	607	-	215	823	101.9	46.2	148.2
Total Proved	1,205	-	1,507	2,712	244.3	113.3	357.6
Probable	514	-	755	1,269	468.8	142.2	611.0
Total Gross Proved Plus Probable	**1,719**	**-**	**2,262**	**3,980**	**713.1**	**255.5**	**968.5**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	884	588	2,843	4,316	138.6	100.1	238.7
Developed non-producing	23	13	126	162	14.3	8.3	22.6
Undeveloped	680	100	1,206	1,986	105.5	88.1	193.5
Total Proved	1,588	701	4,175	6,463	258.4	196.4	454.7
Probable	694	191	2,913	3,798	473.9	214.6	688.4
Total Gross Proved Plus Probable	**2,282**	**891**	**7,088**	**10,261**	**732.2**	**411.0**	**1,143.2**

* Numbers may not add due to rounding

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) "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.

c) "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.

d) "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.

e) "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.

f) "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.

g) "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 Oil and Gas Reserves [(1)]
(Forecast Prices and Costs; After Royalties)

As at December 31, 2014

Canadian Operations

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	278	517	1,378	2,173	8.0	29.9	37.9
Developed non-producing	11	8	73	92	-	1.8	1.8
Undeveloped	70	62	855	987	2.7	33.8	36.5
Total Proved	359	588	2,306	3,252	10.7	65.5	76.2
Probable	164	164	1,805	2,133	3.6	56.2	59.9
Total Net Proved Plus Probable	**522**	**752**	**4,111**	**5,386**	**14.3**	**121.8**	**136.1**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	463	-	1,105	1,568	99.9	48.2	148.2
Developed non-producing	9	-	36	45	11.2	4.8	16.0
Undeveloped	475	-	183	657	79.8	36.4	116.2
Total Proved	946	-	1,324	2,270	190.9	89.5	280.3
Probable	398	-	707	1,105	360.7	111.9	472.6
Total Net Proved Plus Probable	**1,344**	**-**	**2,030**	**3,375**	**551.6**	**201.3**	**752.9**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				Oil & NGLs (MMbbls)		
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved							
Developed producing	741	517	2,483	3,741	107.9	78.1	186.1
Developed non-producing	20	8	109	137	11.2	6.6	17.8
Undeveloped	544	62	1,038	1,645	82.5	70.2	152.7
Total Proved	1,305	588	3,630	5,522	201.6	155.0	356.5
Probable	562	164	2,512	3,238	364.3	168.1	532.4
Total Net Proved Plus Probable	**1,867**	**752**	**6,142**	**8,760**	**565.9**	**323.1**	**889.0**

* Numbers may not add due to rounding

Notes:

(1) Definitions

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

b) "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.

c) "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.

d) "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.

e) "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.

f) "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.

g) "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, 2014

Canadian Operations

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	4,059	3,411	2,850	2,446	2,153
Developed non-producing	332	246	196	165	143
Undeveloped	3,633	2,062	1,275	828	551
Total Proved	8,024	5,719	4,321	3,439	2,847
Probable	9,937	4,790	2,799	1,831	1,288
Total Proved Plus Probable	**17,961**	**10,509**	**7,120**	**5,270**	**4,135**

USA Operations

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	9,928	6,373	4,769	3,866	3,286
Developed non-producing	886	530	381	302	254
Undeveloped	6,529	3,159	1,786	1,078	657
Total Proved	17,343	10,062	6,936	5,246	4,197
Probable	30,004	13,032	6,928	4,113	2,594
Total Proved Plus Probable	**47,347**	**23,094**	**13,864**	**9,359**	**6,791**

Total Encana

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	13,987	9,784	7,619	6,312	5,439
Developed non-producing	1,218	776	577	467	397
Undeveloped	10,162	5,221	3,061	1,906	1,208
Total Proved	25,367	15,781	11,257	8,685	7,044
Probable	39,941	17,822	9,727	5,944	3,882
Total Proved Plus Probable	**65,308**	**33,603**	**20,984**	**14,629**	**10,926**

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

As at December 31, 2014

Canadian Operations

($ millions)	Future Net Revenue After Future Income Tax and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed producing	3,377	2,907	2,454	2,119	1,872
Developed non-producing	255	188	149	125	108
Undeveloped	2,826	1,559	929	574	355
Total Proved	6,458	4,654	3,532	2,818	2,335
Probable	7,489	3,548	2,032	1,299	890
Total Proved Plus Probable	**13,947**	**8,202**	**5,564**	**4,117**	**3,225**

USA Operations

($ millions)	Future Net Revenue After Future Income Tax and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed producing	9,275	6,182	4,694	3,824	3,254
Developed non-producing	563	386	308	263	231
Undeveloped	4,164	2,030	1,151	688	407
Total Proved	14,002	8,598	6,153	4,775	3,892
Probable	19,152	8,274	4,357	2,549	1,574
Total Proved Plus Probable	**33,154**	**16,872**	**10,510**	**7,324**	**5,466**

Total Encana

($ millions)	Future Net Revenue After Future Income Tax and Discounted at 0%	5%	10%	15%	20%
Proved					
Developed producing	12,652	9,089	7,148	5,943	5,126
Developed non-producing	818	574	457	388	339
Undeveloped	6,990	3,589	2,080	1,262	762
Total Proved	20,460	13,252	9,685	7,593	6,227
Probable	26,641	11,822	6,389	3,848	2,464
Total Proved Plus Probable	**47,101**	**25,074**	**16,074**	**11,441**	**8,691**

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

As at December 31, 2014

	Canadian Operations		USA Operations		Total	
($ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Revenues	23,337	44,332	39,484	103,712	62,821	148,044
Royalties and production / mineral taxes	3,577	7,221	9,965	27,519	13,542	34,740
Operating costs	8,881	14,247	8,145	16,628	17,026	30,875
Development costs	2,189	4,168	3,242	11,153	5,431	15,321
Abandonment and reclamation costs	666	735	789	1,065	1,455	1,800
Future net revenue, before income taxes	8,024	17,961	17,343	47,347	25,367	65,308
Income tax	1,566	4,014	3,341	14,193	4,907	18,207
Future Net Revenue, After Income Taxes	**6,458**	**13,947**	**14,002**	**33,154**	**20,460**	**47,101**

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

As at December 31, 2014

Reserves Category	Production Group	Future Net Revenue Before Income Taxes discounted at 10%/yr	Unit Value	
Proved	Shale Gas and Coalbed Methane (including by-products)	1,764	1.05	$/Mcf (1)
	Associated and Non-associated Gas (including by-products)	4,423	1.30	$/Mcf (1)
	Tight Oil (including solution gas and other by-products)	5,070	27.93	$/bbl (2)
	Total	**11,257**		
Proved Plus Probable	Shale Gas and Coalbed Methane (including by-products)	2,471	1.19	$/Mcf (1)
	Associated and Non-associated Gas (including by-products)	6,969	1.20	$/Mcf (1)
	Tight Oil (including solution gas and other by-products)	11,544	21.42	$/bbl (2)
	Total	**20,984**		

Notes:
(1) Unit values are based on net natural gas reserves volumes.
(2) Unit values are based on net oil reserves volumes.

Price Assumptions (Forecast Prices)

The following table of natural gas and oil benchmark prices, exchange rates and inflation rates summarizes the assumptions utilized by the IQREs in estimating Encana's reserves data using forecast prices and costs. NGLs prices (ethane, propane, butanes, pentanes plus, condensate or mixtures thereof) are typically referenced to delivery points such as Edmonton (Alberta), Conway (Kansas) and Mont Belvieu (Texas). All forecast prices utilized were based on GLJ Petroleum Consultants Ltd. commodity price forecasts effective January 1, 2015, which are available at www.gljpc.com.

	Natural Gas		Oil		Foreign Exchange Rate	Inflation Rate
Year	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton [1] (C$/bbl)	US$/C$	%/yr
2014 [2,3]	4.41	4.44	93.00	94.57	0.905	2.0
2015	3.31	3.31	62.50	64.71	0.850	2.0
2016	3.75	3.77	75.00	80.00	0.875	2.0
2017	4.00	4.02	80.00	85.71	0.875	2.0
2018	4.25	4.27	85.00	91.43	0.875	2.0
2019	4.50	4.53	90.00	97.14	0.875	2.0
2020-2024	4.75-5.68	4.78-5.71	95.00-104.57	102.86-112.67	0.875	2.0
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.875	2.0

Notes:

(1) Light Sweet.
(2) Actual weighted average historical prices for 2014.
(3) Encana's weighted average prices before royalties for 2014 excluding the impact of realized hedging were $4.73/Mcf for natural gas, $81.51/bbl for oil and $48.19/bbl for 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, 2014, presented using forecast prices and costs.

Proved Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	387	841	3,803	5,031	24.7	116.5	141.1	979.7
Extensions and improved recovery	36	-	355	391	5.9	21.3	27.3	92.5
Technical revisions	(23)	70	(218)	(171)	(10.2)	4.6	(5.7)	(34.2)
Discoveries	28	-	-	28	-	4.7	4.7	9.4
Acquisitions	-	-	7	7	-	0.1	0.1	1.2
Dispositions	-	(59)	(873)	(932)	(2.5)	(54.1)	(56.6)	(212.0)
Economic factors	(10)	(37)	(10)	(58)	-	(0.5)	(0.5)	(10.1)
Production	(35)	(113)	(396)	(544)	(3.8)	(9.4)	(13.2)	(103.9)
December 31, 2014	**383**	**701**	**2,668**	**3,752**	**14.0**	**83.1**	**97.2**	**722.5**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	1,093	-	3,794	4,887	66.6	69.6	136.2	950.6
Extensions and improved recovery	497	-	98	594	21.1	8.9	30.0	129.1
Technical revisions	(496)	-	(166)	(662)	2.0	(2.1)	(0.1)	(110.4)
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	300	-	-	300	189.5	68.2	257.7	307.7
Dispositions	(28)	-	(1,875)	(1,903)	(17.9)	(24.5)	(42.4)	(359.5)
Economic factors	(5)	-	(65)	(69)	(0.7)	(0.7)	(1.4)	(12.9)
Production	(157)	-	(279)	(436)	(16.4)	(6.1)	(22.5)	(95.1)
December 31, 2014	**1,205**	**-**	**1,507**	**2,712**	**244.3**	**113.3**	**357.6**	**809.5**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	1,480	841	7,597	9,918	91.3	186.0	277.3	1,930.3
Extensions and improved recovery	533	-	453	986	27.1	30.2	57.3	221.6
Technical revisions	(519)	70	(384)	(833)	(8.2)	2.4	(5.7)	(144.6)
Discoveries	28	-	-	28	-	4.7	4.7	9.4
Acquisitions	300	-	7	307	189.5	68.3	257.8	309.0
Dispositions	(28)	(59)	(2,748)	(2,835)	(20.4)	(78.6)	(99.0)	(571.5)
Economic factors	(15)	(37)	(75)	(127)	(0.7)	(1.2)	(1.9)	(23.1)
Production	(192)	(113)	(674)	(980)	(20.2)	(15.5)	(35.7)	(199.0)
December 31, 2014	**1,588**	**701**	**4,175**	**6,463**	**258.4**	**196.4**	**454.7**	**1,532.0**

* Numbers may not add due to rounding

Probable Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	203	156	1,997	2,356	21.3	71.0	92.4	485.0
Extensions and improved recovery	20	-	130	150	0.3	8.2	8.5	33.5
Technical revisions	(68)	56	583	572	(15.3)	13.6	(1.7)	93.6
Discoveries	50	-	-	50	-	13.1	13.1	21.4
Acquisitions	-	-	25	25	-	0.3	0.3	4.4
Dispositions	-	(14)	(578)	(593)	(1.3)	(33.8)	(35.1)	(133.8)
Economic factors	(24)	(8)	1	(31)	-	0.1	0.1	(5.1)
Production	-	-	-	-	-	-	-	-
December 31, 2014	**180**	**191**	**2,158**	**2,529**	**5.1**	**72.4**	**77.5**	**498.9**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	998	-	1,283	2,281	29.6	38.5	68.1	448.4
Extensions and improved recovery	84	-	140	224	18.8	8.9	27.7	64.9
Technical revisions	(993)	-	(64)	(1,057)	(6.6)	(2.4)	(9.0)	(185.1)
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	433	-	-	433	435.3	113.4	548.7	620.8
Dispositions	(7)	-	(556)	(563)	(6.8)	(15.1)	(21.9)	(115.8)
Economic factors	-	-	(49)	(49)	(1.6)	(1.0)	(2.6)	(10.9)
Production	-	-	-	-	-	-	-	-
December 31, 2014	**514**	**-**	**755**	**1,269**	**468.8**	**142.2**	**611.0**	**822.4**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	1,201	156	3,280	4,637	51.0	109.5	160.5	933.4
Extensions and improved recovery	103	-	270	374	19.1	17.1	36.1	98.4
Technical revisions	(1,061)	56	519	(485)	(21.8)	11.2	(10.7)	(91.5)
Discoveries	50	-	-	50	-	13.1	13.1	21.4
Acquisitions	433	-	25	458	435.3	113.7	549.0	625.3
Dispositions	(7)	(14)	(1,134)	(1,155)	(8.1)	(49.0)	(57.0)	(249.6)
Economic factors	(24)	(8)	(48)	(81)	(1.6)	(1.0)	(2.6)	(16.0)
Production	-	-	-	-	-	-	-	-
December 31, 2014	**694**	**191**	**2,913**	**3,798**	**473.9**	**214.6**	**688.4**	**1,321.3**

* Numbers may not add due to rounding

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

Canadian Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	590	997	5,800	7,387	46.0	187.5	233.5	1,464.7
Extensions and improved recovery	56	-	485	541	6.2	29.5	35.7	125.9
Technical revisions	(91)	126	366	400	(25.5)	18.2	(7.3)	59.4
Discoveries	78	-	-	78	-	17.7	17.7	30.7
Acquisitions	-	-	32	32	-	0.4	0.4	5.7
Dispositions	-	(73)	(1,452)	(1,525)	(3.8)	(87.9)	(91.7)	(345.8)
Economic factors	(34)	(45)	(9)	(89)	-	(0.5)	(0.5)	(15.3)
Production	(35)	(113)	(396)	(544)	(3.8)	(9.4)	(13.2)	(103.9)
December 31, 2014	**563**	**891**	**4,826**	**6,280**	**19.1**	**155.5**	**174.6**	**1,221.4**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	2,091	-	5,077	7,168	96.2	108.1	204.3	1,399.0
Extensions and improved recovery	581	-	237	818	39.9	17.8	57.7	194.0
Technical revisions	(1,489)	-	(230)	(1,719)	(4.5)	(4.6)	(9.1)	(295.6)
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	733	-	-	733	624.8	181.6	806.4	928.6
Dispositions	(35)	-	(2,430)	(2,466)	(24.7)	(39.7)	(64.3)	(475.2)
Economic factors	(5)	-	(114)	(119)	(2.3)	(1.7)	(4.0)	(23.8)
Production	(157)	-	(279)	(436)	(16.4)	(6.1)	(22.5)	(95.1)
December 31, 2014	**1,719**	**-**	**2,262**	**3,980**	**713.1**	**255.5**	**968.5**	**1,631.9**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)			**Total** (MMBOE)
	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total	
December 31, 2013	2,681	997	10,877	14,555	142.3	295.6	437.8	2,863.7
Extensions and improved recovery	637	-	723	1,359	46.1	47.3	93.4	320.0
Technical revisions	(1,580)	126	136	(1,319)	(30.0)	13.6	(16.4)	(236.2)
Discoveries	78	-	-	78	-	17.7	17.7	30.7
Acquisitions	733	-	32	765	624.8	182.0	806.8	934.2
Dispositions	(35)	(73)	(3,882)	(3,990)	(28.5)	(127.5)	(156.0)	(821.1)
Economic factors	(39)	(45)	(123)	(207)	(2.3)	(2.2)	(4.5)	(39.1)
Production	(192)	(113)	(674)	(980)	(20.2)	(15.5)	(35.7)	(199.0)
December 31, 2014	**2,282**	**891**	**7,088**	**10,261**	**732.2**	**411.0**	**1,143.2**	**2,853.3**

* Numbers may not add due to rounding

Undeveloped Reserves, Significant Factors or Uncertainties and Future Development Costs

Undeveloped Reserves
(Forecast Prices and Costs; Before Royalties)

Proved and probable undeveloped reserves are attributed where warranted on the basis of economics, 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, 2014 are scheduled for development within the next five and eight years, respectively. Proved and probable undeveloped reserves are reviewed annually for retention or reclassification if development has not proceeded as previously planned.

The following tables disclose, for each product type, the volumes of proved undeveloped and probable undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, prior to that time. First attributed volumes are those which were initially booked in the year in question.

Proved Undeveloped Reserves	**Natural Gas** (Bcf)							
	Shale Gas		**Coalbed Methane**		**Conventional Gas**		**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
Prior	2,981	2,981	651	651	3,942	3,942	7,574	7,574
2012	286	2,666	112	540	906	2,881	1,304	6,087
2013	137	646	-	122	823	2,622	960	3,390
2014	637	680	-	100	317	1,206	954	1,986

* Numbers may not add due to rounding

Proved Undeveloped Reserves	**Oil & NGLs** (MMbbls)					
	Tight Oil		**NGLs**		**Total**	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	17.4	17.4	64.4	64.4	81.8	81.8
2012	20.4	30.3	54.0	140.3	74.4	170.7
2013	23.0	39.5	40.4	100.7	63.5	140.2
2014	93.1	105.5	53.2	88.1	146.3	193.5

* Numbers may not add due to rounding

Probable Undeveloped Reserves	**Natural Gas** (Bcf)							
	Shale Gas		**Coalbed Methane**		**Conventional Gas**		**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
Prior	3,880	3,880	232	232	4,085	4,085	8,197	8,197
2012	1,505	3,210	11	137	1,600	3,417	3,116	6,764
2013	923	1,054	-	11	1,020	2,580	1,943	3,645
2014	516	540	-	11	505	2,371	1,021	2,921

* Numbers may not add due to rounding

Probable Undeveloped Reserves	**Oil & NGLs** (MMbbls)					
	Tight Oil		**NGLs**		**Total**	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	16.0	16.0	36.7	36.7	52.7	52.7
2012	56.8	68.2	76.8	127.1	133.6	195.3
2013	35.4	42.7	46.9	92.3	82.2	134.9
2014	458.3	467.5	156.4	201.6	614.8	669.1

* Numbers may not add due to rounding

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.

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 Operations		USA Operations		Total Encana	
($ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
2015	278	397	895	1,492	1,173	1,889
2016	514	664	678	1,547	1,192	2,211
2017	647	964	532	1,434	1,179	2,398
2018	338	836	498	1,654	836	2,490
2019	285	416	371	1,602	656	2,018
Remainder	127	891	268	3,424	395	4,315
Total	**2,189**	**4,168**	**3,242**	**11,153**	**5,431**	**15,321**

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 flows, available cash balances, divestitures, joint ventures, or a combination of these. In addition, the Company currently has available capacity on its credit facilities and shelf prospectus.

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 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 2014, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material. Encana's current estimate of the total undiscounted future abandonment and reclamation costs to be incurred is approximately $3.6 billion ($502 million discounted at 10 percent). As at December 31, 2014, Encana has recorded an asset retirement obligation of $913 million. These estimates include the abandonment of 19,510 net wells. Over the next three years, Encana's net well abandonment and reclamation cost is expected to total $268 million ($217 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

The Company currently estimates that it will pay income tax in 2015.

2014 Costs Incurred

($ millions)	Canadian Operations	USA Operations (1,2)	Total (1,2)
Acquisitions			
Unproved	15	5,452	5,467
Proved	6	5,008	5,014
Total acquisitions	21	10,460	10,481
Exploration costs	10	38	48
Development costs	1,216	1,247	2,463
Total costs incurred	**1,247**	**11,745**	**12,992**

Notes:
(1) Unproved includes $5,338 million from the acquisition of Athlon.
(2) Proved includes $2,127 million from the acquisition of Athlon.

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, 2014.

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	12,246	11,472	231	201	12,477	11,673	898	686	133	93	1,031	779
British Columbia	913	812	-	-	913	812	166	133	3	-	169	133
Nova Scotia	4	4	-	-	4	4	-	-	-	-	-	-
Total Canadian Operations	**13,163**	**12,288**	**231**	**201**	**13,394**	**12,489**	**1,064**	**819**	**136**	**93**	**1,200**	**912**
Colorado	5,017	3,690	-	-	5,017	3,690	865	725	-	-	865	725
Kansas	1	1	-	-	1	1	-	-	-	-	-	-
Louisiana	561	278	5	5	566	283	4	3	-	-	4	3
Mississippi	-	-	35	19	35	19	-	-	6	4	6	4
Montana	-	-	-	-	-	-	1	1	-	-	1	1
North Dakota	2	-	9	-	11	-	-	-	-	-	-	-
New Mexico	161	55	172	140	333	195	-	-	22	19	22	19
Texas	-	-	1,526	1,430	1,526	1,430	-	-	181	163	181	163
Utah	4	2	-	-	4	2	-	-	-	-	-	-
Wyoming	404	309	7	6	411	315	135	94	-	-	135	94
Total USA Operations	**6,150**	**4,335**	**1,754**	**1,600**	**7,904**	**5,935**	**1,005**	**823**	**209**	**186**	**1,214**	**1,009**
Total Encana	**19,313**	**16,623**	**1,985**	**1,801**	**21,298**	**18,424**	**2,069**	**1,642**	**345**	**279**	**2,414**	**1,921**

Notes:

(1) Encana has varying royalty interests in approximately 2,933 natural gas wells and approximately 203 oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: approximately 23,465 gross natural gas wells (22,066 net wells); and approximately 182 gross oil wells (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 2015, 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 as at December 31, 2014 and the net acres with no attributed reserves for which we expect our rights to explore, develop and exploit to expire during 2015.

(thousands of acres)	Gross Acres (1)	Net Acres (1)	Net Acres Expiring Within One Year
Canada			
Alberta	2,002	1,387	184
British Columbia	838	576	105
Newfoundland and Labrador	35	2	-
Northwest Territories	45	12	-
Nova Scotia	21	10	-
Total Canada	**2,941**	**1,987**	**289**
United States			
Colorado	766	716	7
Louisiana	322	164	-
Mississippi	240	175	37
New Mexico	329	187	-
Texas	71	91	8
Wyoming	224	194	10
Other	11	10	2
Total United States	**1,963**	**1,537**	**64**
International			
Australia	104	40	-
Total International	**104**	**40**	**-**
Total	**5,008**	**3,564**	**353**

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
2014 [3]											
Canadian Operations	2	1	1	1	2	1	-	-	2	7	3
USA Operations	2	2	4	-	-	-	-	-	-	6	2
Total	**4**	**3**	**5**	**1**	**2**	**1**	**-**	**-**	**2**	**13**	**5**

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, 2014, Encana was in the process of drilling the following exploratory and development wells: approximately 7 gross wells (7 net wells) in Canada; and approximately 29 gross wells (20 net wells) in the U.S.

Development Wells Drilled [1,2]

	Gas		Oil		Service		Dry and Abandoned		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2014 [3]											
Canadian Operations	299	255	22	22	5	3	-	-	37	363	280
USA Operations	239	82	144	120	-	-	1	-	11	395	202
Total	**538**	**337**	**166**	**142**	**5**	**3**	**1**	**-**	**48**	**758**	**482**

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, 2014, Encana was in the process of drilling the following exploratory and development wells: approximately 7 gross wells (7 net wells) in Canada; and approximately 29 gross wells (20 net wells) in the U.S.

Production Volumes (Before Royalties)

2015 Production Estimates (Before Royalties)

The following table summarizes the total volume of production estimated for the year ended December 31, 2015, 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.

Canadian Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)		
(annual)	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved	39	100	295	433	2.6	7.7	10.3
Probable	5	4	20	30	0.3	1.3	1.5
Total Proved Plus Probable	**44**	**104**	**315**	**463**	**2.8**	**9.0**	**11.8**

* Numbers may not add due to rounding

USA Operations

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)		
(annual)	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved	117	-	154	271	29.6	9.9	39.5
Probable	5	-	2	7	5.9	1.3	7.2
Total Proved Plus Probable	**122**	**-**	**156**	**278**	**35.5**	**11.2**	**46.7**

* Numbers may not add due to rounding

Total Encana

	Natural Gas (Bcf)				**Oil & NGLs** (MMbbls)		
(annual)	Shale Gas	Coalbed Methane	Conventional Gas	Total	Tight Oil	NGLs	Total
Proved	156	100	449	704	32.1	17.6	49.8
Probable	10	4	23	37	6.2	2.6	8.8
Total Proved Plus Probable	**166**	**104**	**471**	**741**	**38.3**	**20.2**	**58.6**

* Numbers may not add due to rounding

2014 Production Volumes by Country
(Before Royalties)

(average daily)	2014 Annual	Q4	Q3	Q2	Q1
Shale Gas (MMcf/d)					
Canadian Operations	97	96	102	92	98
USA Operations	444	401	443	495	437
	541	497	545	587	535
Coalbed Methane (MMcf/d)					
Canadian Operations	333	297	331	345	361
USA Operations	-	-	-	-	-
	333	297	331	345	361
Conventional Gas (MMcf/d)					
Canadian Operations	1,081	859	1,073	1,172	1,225
USA Operations	750	511	563	835	1,101
	1,831	1,370	1,636	2,007	2,326
Total Produced Gas (MMcf/d)					
Canadian Operations	1,511	1,252	1,506	1,609	1,684
USA Operations	1,194	912	1,006	1,330	1,538
	2,705	2,164	2,512	2,939	3,222
Tight Oil (Mbbls/d)					
Canadian Operations	15.2	11.1	16.4	15.6	17.7
USA Operations	44.9	74.3	60.2	25.0	19.2
	60.1	85.4	76.6	40.6	36.9
NGLs (Mbbls/d)					
Canadian Operations	26.8	20.8	30.6	27.6	28.3
USA Operations	16.7	23.0	17.6	12.7	13.5
	43.5	43.8	48.2	40.3	41.8
Total Oil & NGLs (Mbbls/d)					
Canadian Operations	42.0	31.9	47.0	43.2	46.0
USA Operations	61.6	97.3	77.8	37.7	32.7
	103.6	129.2	124.8	80.9	78.7

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)

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Shale Gas ($/Mcf)					
Canadian Operations					
Price, before royalties	4.02	3.48	3.79	4.25	4.61
Royalties	0.06	0.05	0.05	0.05	0.10
Production and mineral taxes	-	-	-	-	-
Transportation and processing	2.71	2.78	2.50	2.80	2.77
Operating	0.39	0.20	0.52	0.41	0.44
Netback	0.86	0.45	0.72	0.99	1.30
USA Operations					
Price, before royalties	4.18	3.63	3.68	4.49	4.86
Royalties	0.88	0.85	0.76	0.93	0.99
Production and mineral taxes	0.06	0.09	0.07	0.04	0.06
Transportation and processing	0.93	1.05	0.97	0.92	0.79
Operating	0.35	0.48	0.32	0.31	0.30
Netback	1.96	1.16	1.56	2.29	2.72
Total Encana					
Price, before royalties	4.15	3.60	3.70	4.45	4.81
Royalties	0.74	0.69	0.62	0.79	0.83
Production and mineral taxes	0.05	0.08	0.05	0.03	0.05
Transportation and processing	1.25	1.38	1.26	1.21	1.16
Operating	0.36	0.43	0.35	0.33	0.33
Netback	**1.75**	**1.02**	**1.42**	**2.09**	**2.44**
Coalbed Methane ($/Mcf)					
Canadian Operations and Total Encana					
Price, before royalties	4.14	3.60	3.97	4.29	4.62
Royalties	0.48	0.56	0.46	0.47	0.46
Production and mineral taxes	0.04	0.05	0.04	0.01	0.06
Transportation and processing	0.55	0.66	0.43	0.49	0.62
Operating	0.96	0.97	0.84	0.88	1.14
Netback	**2.11**	**1.36**	**2.20**	**2.44**	**2.34**

Netbacks by Country
(Before Royalties)

	2014				
	Annual	Q4	Q3	Q2	Q1
Conventional Gas ($/Mcf)					
Canadian Operations					
Price, before royalties	5.10	3.98	3.65	4.21	8.06
Royalties	0.35	0.33	0.25	0.32	0.46
Production and mineral taxes	-	-	-	-	-
Transportation and processing	1.54	1.70	1.51	1.59	1.41
Operating	0.37	0.35	0.36	0.39	0.38
Netback	2.84	1.60	1.53	1.91	5.81
USA Operations					
Price, before royalties	4.88	4.20	4.30	4.87	5.52
Royalties	0.85	0.58	0.66	0.89	1.03
Production and mineral taxes	0.12	0.17	(0.26)	0.17	0.27
Transportation and processing	1.83	2.35	2.37	1.78	1.33
Operating	0.65	0.73	0.71	0.68	0.57
Netback	1.43	0.37	0.82	1.35	2.32
Total Encana					
Price, before royalties	5.01	4.06	3.87	4.49	6.86
Royalties	0.55	0.42	0.39	0.56	0.73
Production and mineral taxes	0.05	0.07	(0.09)	0.07	0.13
Transportation and processing	1.66	1.94	1.81	1.67	1.37
Operating	0.49	0.49	0.48	0.51	0.47
Netback	**2.26**	**1.14**	**1.28**	**1.68**	**4.16**
Total Produced Gas ($/Mcf)					
Canadian Operations					
Price, before royalties	4.82	3.85	3.73	4.23	7.13
Royalties	0.36	0.36	0.29	0.34	0.44
Production and mineral taxes	0.01	0.01	0.01	-	0.01
Transportation and processing	1.40	1.54	1.34	1.43	1.32
Operating	0.50	0.49	0.48	0.50	0.55
Netback	2.55	1.45	1.61	1.96	4.81
USA Operations					
Price, before royalties	4.62	3.95	4.03	4.73	5.33
Royalties	0.86	0.70	0.70	0.91	1.02
Production and mineral taxes	0.10	0.14	(0.11)	0.12	0.21
Transportation and processing	1.49	1.78	1.75	1.46	1.18
Operating	0.54	0.62	0.53	0.54	0.49
Netback	1.63	0.71	1.16	1.70	2.43
Total Encana					
Price, before royalties	4.73	3.89	3.85	4.46	6.27
Royalties	0.58	0.50	0.45	0.60	0.72
Production and mineral taxes	0.05	0.07	(0.04)	0.06	0.11
Transportation and processing	1.44	1.64	1.51	1.44	1.25
Operating	0.52	0.54	0.50	0.52	0.52
Netback	**2.14**	**1.14**	**1.43**	**1.84**	**3.67**

Netbacks by Country (Before Royalties)

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Total Tight Oil ($/bbl)					
Canadian Operations					
Price, before royalties	82.39	65.58	85.42	90.60	82.97
Royalties	8.35	9.84	8.64	9.56	6.03
Production and mineral taxes	1.74	0.25	1.72	2.67	1.87
Transportation and processing	9.49	12.03	7.64	10.59	8.63
Operating	5.12	10.14	5.28	2.54	4.07
Netback	57.69	33.32	62.14	65.24	62.37
USA Operations					
Price, before royalties	81.21	66.15	91.63	94.43	89.99
Royalties	16.26	13.04	19.51	17.83	16.50
Production and mineral taxes	3.72	2.86	3.72	5.00	5.45
Transportation and processing	-	-	-	-	-
Operating	7.03	7.49	8.01	5.28	4.43
Netback	54.20	42.76	60.39	66.32	63.61
Total Encana					
Price, before royalties	81.51	66.07	90.30	92.95	86.62
Royalties	14.25	12.62	17.18	14.64	11.48
Production and mineral taxes	3.22	2.52	3.29	4.11	3.73
Transportation and processing	2.40	1.57	1.64	4.08	4.13
Operating	6.55	7.83	7.42	4.22	4.25
Netback	**55.09**	**41.53**	**60.77**	**65.90**	**63.03**
Total NGLs ($/bbl) [(1)]					
Canadian Operations					
Price, before royalties	53.97	53.39	54.36	51.75	56.19
Royalties	6.91	5.34	6.07	7.97	7.99
Production and mineral taxes	-	-	-	-	-
Transportation and processing	0.90	1.59	1.72	0.24	0.11
Operating	-	-	-	-	-
Netback	46.16	46.46	46.57	43.54	48.09
USA Operations					
Price, before royalties	38.91	28.84	39.15	44.56	50.76
Royalties	6.95	5.42	7.02	7.59	8.90
Production and mineral taxes	2.17	1.51	1.94	2.73	3.11
Transportation and processing	1.16	1.67	2.20	-	-
Operating	-	-	-	-	-
Netback	28.63	20.24	27.99	34.24	38.75
Total Encana					
Price, before royalties	48.19	40.50	48.81	49.49	54.43
Royalties	6.93	5.38	6.42	7.85	8.29
Production and mineral taxes	0.83	0.79	0.71	0.86	1.00
Transportation and processing	1.00	1.63	1.90	0.16	0.08
Operating	-	-	-	-	-
Netback	**39.43**	**32.70**	**39.78**	**40.62**	**45.06**

Note:
(1) Operating costs related to Shale Gas, Coalbed Methane and Conventional Gas are not allocated to NGLs.

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Total Oil & NGLs ($/bbl)					
Canadian Operations					
Price, before royalties	64.26	57.63	65.20	65.80	66.51
Royalties	7.43	6.90	6.97	8.55	7.24
Production and mineral taxes	0.63	0.09	0.60	0.97	0.72
Transportation and processing	4.01	5.23	3.79	3.98	3.39
Operating	1.85	3.53	1.84	0.92	1.57
Netback	50.34	41.88	52.00	51.38	53.59
USA Operations					
Price, before royalties	69.72	57.33	79.75	77.61	73.83
Royalties	13.73	11.24	16.69	14.38	13.37
Production and mineral taxes	3.30	2.54	3.32	4.24	4.48
Transportation and processing	0.32	0.40	0.50	-	-
Operating	5.12	5.72	6.20	3.50	2.60
Netback	47.25	37.43	53.04	55.49	53.38
Total Encana					
Price, before royalties	67.50	57.40	74.27	71.30	69.55
Royalties	11.17	10.17	13.02	11.26	9.79
Production and mineral taxes	2.22	1.93	2.29	2.49	2.28
Transportation and processing	1.81	1.59	1.74	2.13	1.98
Operating	3.80	5.18	4.55	2.12	2.00
Netback	**48.50**	**38.53**	**52.67**	**53.30**	**53.50**

Impact of Realized Hedging on Encana's Netbacks (Before Royalties)

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas ($/Mcf)					
Canadian Operations	(0.13)	0.21	0.15	(0.30)	(0.50)
USA Operations	(0.19)	0.16	0.10	(0.35)	(0.47)
Total	(0.16)	0.19	0.13	(0.33)	(0.48)
Oil & NGLs ($/bbl)					
Canadian Operations	1.21	8.25	(0.28)	(1.06)	(0.08)
USA Operations	2.65	7.19	0.20	(1.86)	0.03
Total	2.06	7.45	0.02	(1.43)	(0.04)

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, 2014 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, 2014, 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, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Board of Directors:

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 16, 2015	Canada	708
GLJ Petroleum Consultants Ltd.	January 27, 2015	Canada	6,412
Netherland, Sewell & Associates, Inc.	January 13, 2015	United States	5,467
Cawley, Gillespie & Associates, Inc.	January 16, 2015	United States	8,397
Total			**20,984**

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.
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) GLJ Petroleum Consultants Ltd.
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(signed) Netherland, Sewell & Associates, Inc.
Netherland, Sewell & Associates, Inc.
Dallas, Texas, U.S.A.

(signed) Cawley, Gillespie & Associates, Inc.
Cawley, Gillespie & Associates, Inc.
Fort Worth, Texas, U.S.A.

February 23, 2015

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, 2014, 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 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, on the recommendation of the Reserves Committee, 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) Douglas J. Suttles
Douglas J. Suttles
President & Chief Executive Officer

(signed) David G. Hill
David G. Hill
Executive Vice-President,
Exploration & Business Development

(signed) Clayton H. Woitas
Clayton H. Woitas
Director and Chairman of the Board

(signed) Howard J. Mayson
Howard J. Mayson
Director and Chair of the Reserves Committee

February 24, 2015

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 NGLs 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 historical price for each of the years presented within this Appendix.

Net Proved Reserves (U.S. Protocol)

Natural Gas Reserves

In 2014, Encana's proved natural gas reserves of approximately 5.5 Tcf decreased 2.4 Tcf from 2013 primarily due to sales of reserves in place of 2.4 Tcf, resulting from Encana's strategy to refocus on oil and liquids rich plays.

In 2013, Encana's proved natural gas reserves of approximately 7.9 Tcf decreased 0.9 Tcf from 2012 primarily due to changes in the Company's development plans and the resulting impact on proved undeveloped reserves bookings. Extensions and discoveries of 1.0 Tcf were comparable with the prior year and split approximately one-half in the U.S. and one-half in Canada.

In 2012, Encana's proved natural gas reserves of approximately 8.8 Tcf decreased 4.0 Tcf from 2011 primarily due to the impact of lower 12-month average historical prices and dispositions.

Oil & NGLs Reserves

In 2014, Encana's proved oil reserves of 205.0 MMbbls increased 127.7 MMbbls from 2013 primarily due to purchases of reserves in place of 148.2 MMbbls. These purchases took place in the U.S. and were consistent with Encana's strategy to refocus on oil and liquid rich plays. In 2014, Encana's proved NGLs reserves of 156.7 MMbbls increased 13.2 MMbbls from 2013 primarily due to extensions and discoveries of 31.1 MMbbls, which in turn were partially offset by sales net of purchases of reserves in place of 12.4 MMbbls.

In 2013, Encana's proved oil and NGLs reserves of approximately 220.8 MMbbls increased 10.8 MMbbls from 2012. Extensions and discoveries of 55.8 MMbbls were split approximately one-half in the U.S. and one-half in Canada. Revisions and improved recovery was impacted by a decrease in NGLs reserves primarily due to ethane rejection in the U.S. Ethane rejection is where ethane is not recovered from the production stream as NGLs but is instead sold as natural gas.

In 2012, Encana's proved oil and NGLs reserves of approximately 210.0 MMbbls increased 76.8 MMbbls from 2011 primarily due to activities in the U.S., including the impact of renegotiated gathering and processing agreements. The renegotiated agreements result in Encana receiving additional NGLs volumes from the Company's processed gas, which increased oil and NGLs reserves and reduced natural gas reserves.

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

	Natural Gas (Bcf)			**Oil** (MMbbls)			**NGLs** (MMbbls)		
	Canada	**United States**	**Total**	**Canada**	**United States**	**Total**	**Canada**	**United States**	**Total**
2012									
Beginning of year	6,329	6,511	12,840	5.9	38.2	44.1	89.1	-	89.1
Revisions and improved recovery [3]	(1,497)	(1,701)	(3,198)	3.0	(5.0)	(2.0)	(13.0)	43.9	30.9
Extensions and discoveries	638	338	976	7.4	19.3	26.7	18.5	19.9	38.4
Purchase of reserves in place	38	8	46	-	0.1	0.1	-	-	-
Sale of reserves in place	(461)	(321)	(782)	(0.7)	(2.8)	(3.5)	(1.5)	(1.0)	(2.5)
Production	(497)	(593)	(1,090)	(2.6)	(3.8)	(6.4)	(4.5)	(0.4)	(4.9)
End of year	4,550	4,242	8,792	13.0	46.0	59.0	88.6	62.4	151.0
Developed	2,985	2,628	5,613	9.9	25.0	34.9	37.9	18.1	56.0
Undeveloped	1,565	1,614	3,179	3.1	21.0	24.1	50.7	44.3	95.0
Total	**4,550**	**4,242**	**8,792**	**13.0**	**46.0**	**59.0**	**88.6**	**62.4**	**151.0**
2013									
Beginning of year	4,550	4,242	8,792	13.0	46.0	59.0	88.6	62.4	151.0
Revisions and improved recovery [4]	(256)	(362)	(618)	2.6	(1.2)	1.4	(9.6)	(16.1)	(25.7)
Extensions and discoveries	499	482	981	11.5	14.3	25.8	16.7	13.3	30.0
Purchase of reserves in place	-	7	7	-	0.5	0.5	-	0.1	0.1
Sale of reserves in place	(295)	(1)	(296)	-	-	-	(1.5)	(0.1)	(1.6)
Production	(523)	(491)	(1,014)	(4.3)	(5.1)	(9.4)	(6.8)	(3.5)	(10.3)
End of year	3,975	3,877	7,852	22.8	54.5	77.3	87.4	56.1	143.5
Developed	2,744	2,619	5,363	16.5	31.1	47.6	44.6	24.1	68.7
Undeveloped	1,231	1,258	2,489	6.3	23.4	29.7	42.8	32.0	74.8
Total	**3,975**	**3,877**	**7,852**	**22.8**	**54.5**	**77.3**	**87.4**	**56.1**	**143.5**
2014									
Beginning of year	3,975	3,877	7,852	22.8	54.5	77.3	87.4	56.1	143.5
Revisions and improved recovery [5]	250	(511)	(261)	(5.0)	(2.7)	(7.7)	10.9	(2.6)	8.3
Extensions and discoveries	385	493	879	4.7	21.4	26.1	22.3	8.8	31.1
Purchase of reserves in place	6	234	240	-	148.2	148.2	0.1	52.9	53.0
Sale of reserves in place	(885)	(1,473)	(2,358)	(6.6)	(14.2)	(20.8)	(45.5)	(20.0)	(65.4)
Production	(503)	(355)	(858)	(5.0)	(13.1)	(18.0)	(8.6)	(5.0)	(13.6)
End of year	3,229	2,265	5,494	10.9	194.1	205.0	66.6	90.2	156.7
Developed	2,282	1,606	3,887	8.2	112.3	120.5	31.6	53.4	85.0
Undeveloped	947	660	1,607	2.8	81.8	84.5	34.9	36.8	71.7
Total	**3,229**	**2,265**	**5,494**	**10.9**	**194.1**	**205.0**	**66.6**	**90.2**	**156.7**

* Numbers may not add due to rounding

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 NGLs reserves with any U.S. federal authority or agency other than the SEC.

(3) In 2012, revisions and improved recovery of natural gas included a reduction of 4,589 Bcf due to significantly lower 12-month average historical natural gas prices, partially offset by additions of 1,391 Bcf for technical revisions and improved recovery.

(4) In 2013, revisions and improved recovery of natural gas included a reduction of 2,872 Bcf due to lower proved undeveloped reserves bookings, partially offset by additions of 2,233 Bcf due to significantly higher 12-month average historical gas prices and minor positive revisions.

(5) In 2014, revisions and improved recovery of natural gas included a reduction of 520 Bcf due to changes in the proved undeveloped reserves bookings in the U.S.

Pricing Assumptions (SEC Constant Pricing)

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

	Natural Gas		Oil & NGLs	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton [1] (C$/bbl)
Reserve Pricing [2]				
2012	2.76	2.35	94.71	87.42
2013	3.67	3.14	96.94	93.44
2014	4.34	4.63	94.99	96.40

Notes:
(1) Light Sweet.
(2) All prices were held constant in all future years when estimating net revenues and reserves.

Proved Undeveloped Reserves

Encana's proved undeveloped natural gas reserves represented approximately 29 percent of total proved natural gas reserves at December 31, 2014, a decrease from approximately 32 percent at December 31, 2013. At December 31, 2014, approximately 41 percent of Encana's proved oil reserves were undeveloped, an increase from approximately 38 percent at December 31, 2013. At December 31, 2014, approximately 46 percent of Encana's proved NGLs reserves were undeveloped, a decrease from approximately 52 percent at December 31, 2013.

Bookings of proved undeveloped reserves were predicated on economics, technical merit, commercial considerations and development plans. All of the proved undeveloped reserves at December 31, 2014 are scheduled for development within five years and are attributed to locations that are subject to a development plan adopted by Encana's management. In the evaluation of Encana's reserves at December 31, 2014, the proved undeveloped reserves which have remained or are anticipated to remain undeveloped for five years or more from initial booking are not material.

During 2014, approximately 73.6 MMBOE of proved undeveloped reserves were converted to proved developed reserves. Investments made during 2014 to convert proved undeveloped reserves to proved developed reserves were approximately $0.4 billion.

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.

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

	Canada			United States		
($ millions)	2014	2013	2012	2014	2013	2012
Future cash inflows	19,255	19,039	15,471	26,742	17,217	14,124
Less future:						
Production costs	7,456	7,377	6,273	6,673	4,484	4,095
Development costs	3,276	4,515	5,117	4,087	3,982	4,210
Income taxes	1,727	652	-	2,886	1,615	555
Future net cash flows	6,796	6,495	4,081	13,096	7,136	5,264
Less 10% annual discount for estimated timing of cash flows	2,320	1,836	1,079	6,015	2,978	2,249
Discounted future net cash flows	**4,476**	**4,659**	**3,002**	**7,081**	**4,158**	**3,015**

	Total		
($ millions)	2014	2013	2012
Future cash inflows	45,997	36,256	29,595
Less future:			
Production costs	14,129	11,861	10,368
Development costs	7,363	8,497	9,327
Income taxes	4,613	2,267	555
Future net cash flows	19,892	13,631	9,345
Less 10% annual discount for estimated timing of cash flows	8,335	4,814	3,328
Discounted future net cash flows	**11,557**	**8,817**	**6,017**

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

	Canada			United States		
($ millions)	2014	2013	2012	2014	2013	2012
Balance, beginning of year	4,659	3,002	5,285	4,158	3,015	5,463
Changes resulting from:						
Sales of oil and gas produced during the period	(2,120)	(1,649)	(1,808)	(1,746)	(1,490)	(2,223)
Discoveries and extensions, net of related costs	827	725	509	1,429	633	319
Purchases of proved reserves in place	9	-	7	3,052	16	8
Sales and transfers of proved reserves in place	(1,320)	(304)	(155)	(1,902)	(2)	(369)
Net change in prices and production costs	1,777	2,703	(1,364)	2,567	1,891	(2,106)
Revisions to quantity estimates	314	(178)	(1,290)	(616)	(324)	(2,858)
Accretion of discount	515	311	571	503	333	693
Previously estimated development costs incurred, net of change in future development costs	532	417	946	(3)	708	3,021
Other	(36)	14	(7)	24	(68)	(79)
Net change in income taxes	(681)	(382)	308	(385)	(554)	1,146
Balance, end of year	**4,476**	**4,659**	**3,002**	**7,081**	**4,158**	**3,015**

	Total		
($ millions)	2014	2013	2012
Balance, beginning of year	8,817	6,017	10,748
Changes resulting from:			
Sales of oil and gas produced during the period	(3,866)	(3,139)	(4,031)
Discoveries and extensions, net of related costs	2,256	1,358	828
Purchases of proved reserves in place	3,061	16	15
Sales and transfers of proved reserves in place	(3,222)	(306)	(524)
Net change in prices and production costs	4,344	4,594	(3,470)
Revisions to quantity estimates	(302)	(502)	(4,148)
Accretion of discount	1,018	644	1,264
Previously estimated development costs incurred, net of change in future development costs	529	1,125	3,967
Other	(12)	(54)	(86)
Net change in income taxes	(1,066)	(936)	1,454
Balance, end of year	**11,557**	**8,817**	**6,017**

Results of Operations

($ millions)	Canada 2014	Canada 2013	Canada 2012	United States 2014	United States 2013	United States 2012
Oil and gas revenues, net of royalties, transportation and processing	2,475	2,068	2,205	2,244	2,041	2,713
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	355	419	397	498	551	490
Depreciation, depletion and amortization	625	601	748	992	818	1,102
Impairments	-	-	1,822	-	-	2,842
Operating income (loss)	1,495	1,048	(762)	754	672	(1,721)
Income taxes	376	264	(191)	273	243	(623)
Results of operations	**1,119**	**784**	**(571)**	**481**	**429**	**(1,098)**

($ millions)	Total 2014	Total 2013	Total 2012
Oil and gas revenues, net of royalties, transportation and processing	4,719	4,109	4,918
Less:			
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	853	970	887
Depreciation, depletion and amortization	1,617	1,419	1,850
Impairments	-	-	4,664
Operating income (loss)	2,249	1,720	(2,483)
Income taxes	649	507	(814)
Results of operations	**1,600**	**1,213**	**(1,669)**

Capitalized Costs and Costs Incurred

Capitalized Costs

($ millions)	Canada 2014	Canada 2013	Canada 2012	United States 2014	United States 2013	United States 2012
Proved oil and gas properties	18,271	25,003	26,024	24,279	26,529	24,825
Unproved oil and gas properties	478	598	716	5,655	470	579
Total capital cost	18,749	25,601	26,740	29,934	26,999	25,404
Accumulated DD&A	16,566	23,012	23,962	16,260	22,074	21,236
Net capitalized costs	**2,183**	**2,589**	**2,778**	**13,674**	**4,925**	**4,168**

($ millions)	Other 2014	Other 2013	Other 2012	Total 2014	Total 2013	Total 2012
Proved oil and gas properties	65	71	104	42,615	51,603	50,953
Unproved oil and gas properties	-	-	-	6,133	1,068	1,295
Total capital cost	65	71	104	48,748	52,671	52,248
Accumulated DD&A	65	71	104	32,891	45,157	45,302
Net capitalized costs	**-**	**-**	**-**	**15,857**	**7,514**	**6,946**

Costs Incurred

($ millions)	Canada 2014	Canada 2013	Canada 2012	United States (1,2) 2014	United States (1,2) 2013	United States (1,2) 2012
Acquisitions						
Unproved	15	26	121	5,452	111	235
Proved	6	2	18	5,008	45	5
Total acquisitions	21	28	139	10,460	156	240
Exploration costs	10	22	201	38	412	633
Development costs	1,216	1,343	1,366	1,247	871	1,094
Total costs incurred	**1,247**	**1,393**	**1,706**	**11,745**	**1,439**	**1,967**

($ millions)	Total (1,2) 2014	Total (1,2) 2013	Total (1,2) 2012
Acquisitions			
Unproved	5,467	137	356
Proved	5,014	47	23
Total acquisitions	10,481	184	379
Exploration costs	48	434	834
Development costs	2,463	2,214	2,460
Total costs incurred	**12,992**	**2,832**	**3,673**

Notes:
(1) In 2014, Unproved includes $5,338 million from the acquisition of Athlon.
(2) In 2014, Proved includes $2,127 million from the acquisition of Athlon.

Developed and Undeveloped Landholdings

The following table summarizes Encana's developed, undeveloped and total landholdings as at December 31, 2014.

Landholdings [1 - 7]		Developed		Undeveloped		Total	
(thousands of acres)		Gross	Net	Gross	Net	Gross	Net
Canada							
Alberta	— Crown	1,026	681	1,083	758	2,109	1,439
	— Freehold	1,387	1,260	625	558	2,012	1,818
	— Fee	1	1	2	2	3	3
		2,414	1,942	1,710	1,318	4,124	3,260
British Columbia	— Crown	376	201	983	631	1,359	832
	— Freehold	7	-	-	-	7	-
	— Fee	-	-	1	1	1	1
		383	201	984	632	1,367	833
Newfoundland and Labrador	— Crown	-	-	35	2	35	2
Northwest Territories	— Crown	-	-	45	12	45	12
Nova Scotia	— Crown	20	20	21	10	41	30
Total Canada		**2,817**	**2,163**	**2,795**	**1,974**	**5,612**	**4,137**
United States							
Colorado	— Federal/State	207	196	426	395	633	591
	— Freehold	110	101	87	77	197	178
	— Fee	3	3	14	14	17	17
		320	300	527	486	847	786
Louisiana	— Federal/State	1	1	2	2	3	3
	— Freehold	169	94	111	45	280	139
	— Fee	9	6	62	43	71	49
		179	101	175	90	354	191
Mississippi	— Federal/State	-	-	4	1	4	1
	— Freehold	10	8	233	172	243	180
		10	8	237	173	247	181
New Mexico	— Federal/State	49	30	294	170	343	200
	— Freehold	-	-	9	5	9	5
		49	30	303	175	352	205
Texas	— Federal/State	4	3	2	2	6	5
	— Freehold	132	130	80	67	212	197
		136	133	82	69	218	202
Wyoming	— Federal/State	38	28	173	156	211	184
	— Freehold	5	4	15	12	20	16
		43	32	188	168	231	200
Other	— Federal/State	2	1	6	9	8	10
	— Freehold	2	1	2	1	4	2
	— Fee	-	-	1	-	1	-
		4	2	9	10	13	12
Total United States		**741**	**606**	**1,521**	**1,171**	**2,262**	**1,777**
International							
Australia		-	-	104	40	104	40
Total International		**-**	**-**	**104**	**40**	**104**	**40**
Total		**3,558**	**2,769**	**4,420**	**3,185**	**7,978**	**5,954**

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; (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 1,000 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**
2014 [3]											
Canadian Operations	2	1	1	1	-	-	3	2	2	5	2
USA Operations	2	2	4	-	-	-	6	2	-	6	2
Total	**4**	**3**	**5**	**1**	**-**	**-**	**9**	**4**	**2**	**11**	**4**
2013											
Canadian Operations	31	15	1	1	-	-	32	16	21	53	16
USA Operations	5	5	43	31	-	-	48	36	-	48	36
Total	**36**	**20**	**44**	**32**	**-**	**-**	**80**	**52**	**21**	**101**	**52**
2012											
Canadian Operations	20	15	-	-	-	-	20	15	23	43	15
USA Operations	15	9	45	37	1	1	61	47	-	61	47
Total	**35**	**24**	**45**	**37**	**1**	**1**	**81**	**62**	**23**	**104**	**62**

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, 2014, Encana was in the process of drilling the following exploratory and development wells: approximately 7 gross wells (7 net wells) in Canada; and approximately 29 gross wells (20 net wells) in the U.S.

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
2014 [3]											
Canadian Operations	299	255	22	22	-	-	321	277	37	358	277
USA Operations	239	82	144	120	1	-	384	202	11	395	202
Total	**538**	**337**	**166**	**142**	**1**	**-**	**705**	**479**	**48**	**753**	**479**
2013											
Canadian Operations	329	308	67	66	-	-	396	374	430	826	374
USA Operations	437	201	-	-	-	-	437	201	31	468	201
Total	**766**	**509**	**67**	**66**	**-**	**-**	**833**	**575**	**461**	**1,294**	**575**
2012											
Canadian Operations	356	325	32	32	-	-	388	357	219	607	357
USA Operations	445	237	-	-	1	1	446	238	18	464	238
Total	**801**	**562**	**32**	**32**	**1**	**1**	**834**	**595**	**237**	**1,071**	**595**

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, 2014, Encana was in the process of drilling the following exploratory and development wells: approximately 7 gross wells (7 net wells) in Canada; and approximately 29 gross wells (20 net wells) in the U.S.

Production Volumes (After Royalties)

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

Production Volumes (After Royalties)

	2014				
(average daily)	Annual	Q4	Q3	Q2	Q1
Produced Gas (MMcf/d)					
Canadian Operations	1,378	1,111	1,374	1,463	1,568
USA Operations	972	750	825	1,078	1,241
	2,350	**1,861**	**2,199**	**2,541**	**2,809**
Oil (Mbbls/d)					
Canadian Operations	13.6	9.4	14.7	13.9	16.4
USA Operations	35.8	59.4	47.4	20.3	15.7
	49.4	**68.8**	**62.1**	**34.2**	**32.1**
NGLs (Mbbls/d)					
Canadian Operations	23.6	18.8	27.6	23.5	24.6
USA Operations	13.8	18.8	14.3	10.5	11.2
	37.4	**37.6**	**41.9**	**34.0**	**35.8**
Oil & NGLs (Mbbls/d)					
Canadian Operations	37.2	28.2	42.3	37.4	41.0
USA Operations	49.6	78.2	61.7	30.8	26.9
	86.8	**106.4**	**104.0**	**68.2**	**67.9**

(average daily)	2013	2012
Produced Gas (MMcf/d)		
Canadian Operations	1,432	1,359
USA Operations	1,345	1,622
	2,777	**2,981**
Oil (Mbbls/d)		
Canadian Operations	11.9	7.3
USA Operations	13.9	10.3
	25.8	**17.6**
NGLs (Mbbls/d)		
Canadian Operations	18.5	12.1
USA Operations	9.6	1.3
	28.1	**13.4**
Oil & NGLs (Mbbls/d)		
Canadian Operations	30.4	19.4
USA Operations	23.5	11.6
	53.9	**31.0**

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)

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas ($/Mcf)					
Canadian Operations					
Price, after royalties	4.89	3.93	3.78	4.27	7.17
Production and mineral taxes	0.01	0.01	0.01	-	0.01
Transportation and processing	1.53	1.73	1.47	1.57	1.42
Operating	0.55	0.55	0.52	0.55	0.59
Netback	2.80	1.64	1.78	2.15	5.15
USA Operations					
Price, after royalties	4.62	3.95	4.05	4.72	5.34
Production and mineral taxes	0.12	0.17	(0.14)	0.15	0.26
Transportation and processing	1.83	2.16	2.13	1.80	1.46
Operating	0.66	0.75	0.65	0.67	0.61
Netback	2.01	0.87	1.41	2.10	3.01
Total Encana					
Price, after royalties	4.78	3.94	3.88	4.46	6.37
Production and mineral taxes	0.06	0.08	(0.05)	0.06	0.12
Transportation and processing	1.66	1.90	1.72	1.67	1.44
Operating	0.60	0.63	0.57	0.60	0.60
Netback	**2.46**	**1.33**	**1.64**	**2.13**	**4.21**
Oil ($/bbl)					
Canadian Operations					
Price, after royalties	82.86	66.03	85.78	90.96	83.06
Production and mineral taxes	1.94	0.30	1.92	3.00	2.01
Transportation and processing	10.62	14.26	8.53	11.89	9.31
Operating	5.73	12.02	5.89	2.85	4.39
Netback	64.57	39.45	69.44	73.22	67.35
USA Operations					
Price, after royalties	81.27	66.44	91.55	94.28	89.95
Production and mineral taxes	4.66	3.58	4.72	6.16	6.66
Transportation and processing	-	-	-	-	-
Operating	8.80	9.36	10.16	6.50	5.42
Netback	67.81	53.50	76.67	81.62	77.87
Total Encana					
Price, after royalties	81.71	66.38	90.18	92.93	86.43
Production and mineral taxes	3.91	3.13	4.06	4.87	4.29
Transportation and processing	2.92	1.95	2.02	4.84	4.76
Operating	7.96	9.73	9.15	5.01	4.89
Netback	**66.92**	**51.57**	**74.95**	**78.21**	**72.49**

Netbacks by Country
(After Royalties)

	2014				
	Annual	Q4	Q3	Q2	Q1
NGLs ($/bbl) [(1)]					
Canadian Operations					
Price, after royalties	53.41	53.24	53.61	51.41	55.25
Production and mineral taxes	-	-	-	-	-
Transportation and processing	1.02	1.76	1.91	0.28	0.13
Operating	-	-	-	-	-
Netback	52.39	51.48	51.70	51.13	55.12
USA Operations					
Price, after royalties	38.92	28.54	39.42	44.85	50.58
Production and mineral taxes	2.64	1.84	2.38	3.32	3.75
Transportation and processing	1.42	2.04	2.70	-	-
Operating	-	-	-	-	-
Netback	34.86	24.66	34.34	41.53	46.83
Total Encana					
Price, after royalties	48.09	40.87	48.76	49.39	53.79
Production and mineral taxes	0.97	0.92	0.81	1.02	1.17
Transportation and processing	1.17	1.90	2.18	0.20	0.09
Operating	-	-	-	-	-
Netback	**45.95**	**38.05**	**45.77**	**48.17**	**52.53**
Oil & NGLs ($/bbl)					
Canadian Operations					
Price, after royalties	64.16	57.50	64.79	66.13	66.36
Production and mineral taxes	0.71	0.10	0.67	1.12	0.80
Transportation and processing	4.52	5.92	4.21	4.60	3.80
Operating	2.09	4.00	2.05	1.06	1.75
Netback	56.84	47.48	57.86	59.35	60.01
USA Operations					
Price, after royalties	69.54	57.30	79.43	77.46	73.61
Production and mineral taxes	4.10	3.16	4.18	5.19	5.46
Transportation and processing	0.39	0.49	0.63	-	-
Operating	6.36	7.11	7.80	4.29	3.16
Netback	58.69	46.54	66.82	67.98	64.99
Total Encana					
Price, after royalties	67.24	57.35	73.48	71.23	69.23
Production and mineral taxes	2.65	2.35	2.75	2.95	2.65
Transportation and processing	2.16	1.93	2.09	2.53	2.30
Operating	4.54	6.29	5.46	2.51	2.31
Netback	**57.89**	**46.78**	**63.18**	**63.24**	**61.97**

Note:

(1) Operating costs related to Produced Gas are not allocated to NGLs.

Netbacks by Country
(After Royalties)

	Annual Average	
	2013	**2012**
Produced Gas ($/Mcf)		
Canadian Operations		
Price, after royalties	3.35	2.58
Production and mineral taxes	0.01	-
Transportation and processing	1.37	1.12
Operating	0.61	0.67
Netback	1.36	0.79
USA Operations		
Price, after royalties	3.81	3.03
Production and mineral taxes	0.16	0.11
Transportation and processing	1.47	1.10
Operating	0.69	0.59
Netback	1.49	1.23
Total Encana		
Price, after royalties	3.57	2.83
Production and mineral taxes	0.08	0.06
Transportation and processing	1.42	1.11
Operating	0.65	0.62
Netback	**1.42**	**1.04**
Oil ($/bbl)		
Canadian Operations		
Price, after royalties	83.28	80.25
Production and mineral taxes	2.45	3.00
Transportation and processing	6.89	0.97
Operating	9.11	5.54
Netback	64.83	70.74
USA Operations		
Price, after royalties	90.63	86.77
Production and mineral taxes	6.14	7.09
Transportation and processing	-	0.07
Operating	11.84	6.60
Netback	72.65	73.01
Total Encana		
Price, after royalties	87.25	84.06
Production and mineral taxes	4.45	5.39
Transportation and processing	3.17	0.44
Operating	10.58	6.16
Netback	**69.05**	**72.07**
NGLs ($/bbl) (1)		
Canadian Operations		
Price, after royalties	53.37	65.15
Production and mineral taxes	-	-
Transportation and processing	0.32	0.62
Operating	-	-
Netback	53.05	64.53
USA Operations		
Price, after royalties	40.41	46.42
Production and mineral taxes	2.82	2.94
Transportation and processing	-	-
Operating	-	-
Netback	37.59	43.48
Total Encana		
Price, after royalties	48.95	63.37
Production and mineral taxes	0.96	0.28
Transportation and processing	0.21	0.57
Operating	-	-
Netback	**47.78**	**62.52**

Note:
(1) Operating costs related to Produced Gas are not allocated to NGLs.

Netbacks by Country
(After Royalties)

	Annual Average	
	2013	**2012**
Oil & NGLs ($/bbl)		
Canadian Operations		
Price, after royalties	65.06	70.84
Production and mineral taxes	0.96	1.13
Transportation and processing	2.89	0.75
Operating	3.56	2.09
Netback	57.65	66.87
USA Operations		
Price, after royalties	70.18	82.33
Production and mineral taxes	4.79	6.63
Transportation and processing	-	0.06
Operating	7.02	5.88
Netback	58.37	69.76
Total Encana		
Price, after royalties	67.30	75.12
Production and mineral taxes	2.63	3.18
Transportation and processing	1.63	0.50
Operating	5.07	3.50
Netback	**57.97**	**67.94**

Impact of Realized Hedging on Encana's Netbacks
(After Royalties)

	2014				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas ($/Mcf)					
Canadian Operations	(0.15)	0.24	0.16	(0.33)	(0.53)
USA Operations	(0.24)	0.19	0.12	(0.44)	(0.58)
Total	(0.19)	0.22	0.15	(0.38)	(0.55)
Oil & NGLs ($/bbl)					
Canadian Operations	1.36	9.35	(0.31)	(1.22)	(0.09)
USA Operations	3.29	8.94	0.25	(2.28)	0.04
Total	2.46	9.05	0.02	(1.70)	(0.04)

	Annual Average	
	2013	**2012**
Natural Gas ($/Mcf)		
Canadian Operations	0.51	1.97
USA Operations	0.53	2.01
Total	0.52	1.99
Oil & NGLs ($/bbl)		
Canadian Operations	0.46	-
USA Operations	0.44	-
Total	0.45	-

Note: The Company did not hedge NGLs production for the periods presented.

Appendix E - Audit Committee Mandate

Last updated December 9, 2014.

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 provisions;
- 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 Chair shall be a non-voting member of the Committee. See Quorum for further details.

<u>Appointment of Members</u>

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 independent Director to act as Chair of the Committee. The Board shall appoint the Chair of the Committee.

If the Chair 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 Chair of the Committee presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chair 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.

<u>Meetings</u>

Committee meetings may, by agreement of the Chair 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 Chair of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chair, 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 Chair 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 Vice-President, Finance & Comptroller, the Vice-President, Financial Compliance, Governance & Risk or any vice-president holding a similar role in accounting, risk, compliance and/or 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 judgments, 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 judgmental 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 annual and interim 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). Consideration should be given as to whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such review and discussion should occur before public disclosure and 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 Chair 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 *de minimus* exceptions for non-audit services described, in NI 52-110, the rules and forms under the *Exchange Act*, SEC Regulation S-X or other applicable Canadian or United States federal, provincial and state legislation and regulations, which services 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.