ENCANA CORP
Form 10-K
February 26, 2018
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2017

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-15226

ENCANA CORPORATION

(Exact name of registrant as specified in its charter)

Canada	**98-0355077**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Suite 4400, 500 Centre Street S.E., P.O. Box 2850, Calgary, Alberta, Canada, T2P 2S5

(Address of principal executive offices)

Registrant s telephone number, including area code **(403) 645-2000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each	Name of each exchange

class	on which registered
Common Shares	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [ ] No [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
[ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer , smaller reporting company and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]
	Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act):
Yes [ ] No [X]

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2017	$ 8,563,240,884

Number of registrant s common shares outstanding as of February 16, 2018 973,123,364

Documents Incorporated by Reference

Portions of registrant s definitive proxy statement (Proxy Statement) for the registrant s 2018 annual meeting of shareholders to be held May 1, 2018 (to be filed with the Securities and Exchange Commission prior to April 30, 2018) are incorporated by reference in Part III of this Annual Report on Form 10-K.

Table of Contents

ENCANA CORPORATION

FORM 10-K

TABLE OF CONTENTS

PART I

Items 1 and 2. Business and Properties	5
Item 1A. Risk Factors	24
Item 1B. Unresolved Staff Comments	32
Item 3. Legal Proceedings	32
Item 4. Mine Safety Disclosures	32

PART II

Item 5. Market for Registrant s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities	33
Item 6. Selected Financial Data	36
Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations	37
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	66
Item 8. Financial Statements and Supplementary Data	68
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	126
Item 9A. Controls and Procedures	126
Item 9B. Other Information	126

PART III

Item 10. Directors, Executive Officers and Corporate Governance	127
Item 11. Executive Compensation	127
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters	127
Item 13. Certain Relationships and Related Transactions, and Director Independence	127
Item 14. Principal Accounting Fees and Services	127

PART IV

Item 15. Exhibits and Financial Statement Schedules	128
Signatures	132

Table of Contents

DEFINITIONS

Unless the context otherwise indicates, references to us, we, our, ours, Encana and the Company refer t Corporation and its consolidated subsidiaries. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

AECO means Alberta Energy Company and is the Canadian benchmark price for natural gas.

ASC means Accounting Standards Codification.

ASU means Accounting Standards Update.

bbl or bbls means barrel or barrels.

bbls/d means barrels per day.

Bcf means billion cubic feet.

Bcf/d means billion cubic feet per day.

BOE means barrels of oil equivalent.

BOE/d means barrels of oil equivalent per day.

Btu means British thermal units, a measure of heating value.

DD&A means depreciation, depletion and amortization expenses.

FASB means Financial Accounting Standards Board.

LIBOR means London Interbank Offered Rate.

Mbbls means thousand barrels.

Mbbls/d means thousand barrels per day.

MBOE means thousand barrels of oil equivalent.

MBOE/d means thousand barrels of oil equivalent per day.

Mcf means thousand cubic feet.

Mcf/d means thousand cubic feet per day.

MD&A means Management s Discussion and Analysis of Financial Condition and Results of Operations.

MMbbls means million barrels.

MMbbls/d means million barrels per day.

MMBOE means million barrels of oil equivalent.

MMBOE/d means million barrels of oil equivalent per day.

MMBtu means million Btu.

MMcf means million cubic feet.

MMcf/d means million cubic feet per day.

NGL or NGLs means natural gas liquids.

NYMEX means New York Mercantile Exchange.

NYSE means New York Stock Exchange.

OPEC means Organization of the Petroleum Exporting Countries.

SEC means United States Securities and Exchange Commission.

Standardized measure means the present value of after-tax future net revenues discounted at 10% per annum.

S&P 500 means Standard and Poor s 500 index.

S&P/TSX Composite Index means Standard and Poor s index for Canadian equity markets.

TSX means Toronto Stock Exchange.

U.S. or United States or USA means United States of America.

U.S. GAAP means U.S. Generally Accepted Accounting Principles.

WTI means West Texas Intermediate.

Table of Contents

CONVERSIONS

In this Annual Report on Form 10-K, a conversion of natural gas volumes to BOE is on the basis of six Mcf to one bbl. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value, particularly if used in isolation.

CONVENTIONS

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. In addition, all information provided herein is presented on an after royalties basis.

The term liquids is used to represent oil, NGLs and condensate. The term liquids rich is used to represent natural gas streams with associated liquids volumes. The term play is used to describe an area in which hydrocarbon accumulations or prospects of a given type occur. Encana s focus of development is on hydrocarbon accumulations known to exist over a large areal expanse and/or thick vertical section and are developed using hydraulic fracturing. This type of development typically has a lower geological and/or commercial development risk and lower average decline rate, when compared to conventional development.

The term core asset refers to plays that are the focus of the Company s current capital investment and development plan. The Company continually reviews funding for development of its plays based on strategic fit, profitability and portfolio diversity and, as such, the composition of plays identified as a core asset may change over time.

References to information contained on the Company s website at www.encana.com are not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

FORWARD-LOOKING STATEMENTS AND RISK

This Annual Report on Form 10-K and documents incorporated herein by reference contain certain forward-looking statements or information (collectively, forward-looking statements) within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements include: composition of the Company s core assets, including the allocation of capital and focus of development plans; growth in long-term shareholder value; vision to being a leading North American resource play company; statements with respect to the Company s strategic objectives including capital allocation strategy, focus of investment, growth of high margin liquids volumes, operating and capital efficiencies and ability to preserve balance sheet strength; ability to lower costs and improve efficiencies to achieve competitive advantage, including benefits of integrated supply chain model and self-sourcing; ability to repeat and deploy successful practices across the Company s multi-basin portfolio; balancing commodity portfolio; anticipated commodity prices; success of and benefits from technology and innovation, including cube development approach, precision well targeting and advanced completion designs; reduced dependence on fresh water requirements and anticipated water infrastructure; ability to accelerate activity levels; ability to optimize well and completion designs, including changes to lateral lengths drilled, stage, well spacing and stacking optimization; future well inventory; anticipated drilling, number of drilling rigs and the success thereof; anticipated drilling costs and cycle times; anticipated proceeds and future benefits from various joint venture, partnership and other agreements; expected timing for construction of facilities and costs thereof; expansion of future midstream services; estimates of reserves and resources; expected production and product types; ability to replicate successful test wells to future production; statements regarding anticipated cash flow, non-GAAP cash flow margin

and leverage ratios; anticipated cash and cash equivalents; anticipated hedging and outcomes of risk management program, including ability to leverage marketing fundamentals expertise, exposure to certain commodity prices and foreign exchange, amount of hedged production, market access and physical sales locations; impact of changes in laws and regulations, including recent U.S. tax reform and potential changes to free trade agreements; compliance with environmental legislation and claims related to the purported causes and impact of climate change, and the costs therefrom; adequacy of provisions for abandonment and site reclamation costs; financial flexibility and discipline; access to cash and cash equivalents and other methods of funding; ability to meet financial obligations, manage debt and financial ratios, finance growth and compliance with financial covenants; impact to the Company as a result of a downgrade to its credit rating; access to the Company s credit facilities; planned annualized dividend and the declaration and payment of future dividends, if any; managing capital structure including adjustments to capital spending or dividends, issuing debt or equity, purchasing shares through a normal course issuer bid (NCIB) or repaying existing debt; the Company s planned NCIB, including amounts and number of shares to be acquired, anticipated timeframe, method and location of purchases, and source of

Table of Contents

funding thereof; adequacy of the Company s provision for taxes and legal claims; projections and expectation of meeting the targets contained in the Company s corporate guidance and five-year plan; ability to manage cost inflation and expected cost structures, including expected operating, transportation and processing and administrative expenses; competitiveness and pace of growth of the Company s assets within North America and against its peers; outlook of oil and gas industry generally and impact of geopolitical environment; returns from the Company s core assets; anticipated capital spending plans and source of funding thereof; anticipated staffing levels; expected future interest expense; the Company s commitments and obligations; statements with respect to future ceiling test impairments; and the possible impact and timing of accounting pronouncements, rule changes and standards.

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; ability to access credit facilities and shelf prospectuses; assumptions contained in the Company s corporate guidance, five-year plan and as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of the Company s drive to productivity and efficiencies; results from innovations; expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; and expectations and projections made in light of, and generally consistent with, Encana s historical experience and its perception of historical trends, including with respect to the pace of technological development, benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: ability to generate sufficient cash flow to meet obligations; commodity price volatility; ability to secure adequate transportation and potential pipeline curtailments; variability and discretion of Encana s board of directors (the Board of Directors) to declare and pay dividends, if any; timing and costs of well, facilities and pipeline construction; business interruption, property and casualty losses or unexpected technical difficulties, including impact of weather; counterparty and credit risk; impact of a downgrade in credit rating and its impact on access to sources of liquidity; fluctuations in currency and interest rates; risks inherent in the Company s corporate guidance; failure to achieve cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; changes in or interpretation of royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; risks associated with existing and potential lawsuits and regulatory actions made against the Company; impact of disputes arising with its partners, including suspension of certain obligations and inability to dispose of assets or interests in certain arrangements; the Company s ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities, including future net revenue estimates; risks associated with past and future acquisitions or divestitures of certain assets or other transactions or receipt of 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 o various conditions not being met; and other risks described in Item 1A. Risk Factors of this Annual Report on Form 10-K and risks and uncertainties impacting Encana s business as described from time to time in the Company s other periodic filings with the SEC incorporated by reference in this Annual Report on Form 10-K.

Although the Company believes 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 assumptions, risks and uncertainties referenced above and in the documents incorporated by reference herein are not exhaustive. Forward-looking statements are made as of the date of this document (or, in the case of a document incorporated by reference, the date of such document incorporated by reference) and, except as required by law, the Company undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements

contained or incorporated by reference in this Annual Report on Form 10-K are expressly qualified by these cautionary statements.

The reader should read carefully the risk factors described in the documents incorporated by reference in this Annual Report on Form 10-K for a description of certain risks that could, among other things, cause actual results to differ from these forward-looking statements.

Table of Contents

PART I

Items 1 and 2. Business and Properties

GENERAL

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

Encana s registered and principal office is located at 4400, 500 Centre Street S.E., Calgary, Alberta T2P 2S5, Canada. Encana s common shares are listed and posted for trading on the TSX and on the NYSE under the symbol ECA . Encana is incorporated under the Canada Business Corporations Act (the CBCA) and was formed in 2002 through the business combination of two predecessor companies.

Available Information

Encana is subject to the informational requirements of the United States Securities Exchange Act of 1934, as amended (the Exchange Act) and, in accordance with the Exchange Act, it also files reports with and furnishes other information to the SEC. The public may read any document Encana files with or furnishes to the SEC at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. Readers may also obtain copies of the same documents from the public reference room of the SEC at 100 F Street, N.E., Washington D.C. 20549 by paying a fee. Please call the SEC at 1-800-SEC-0330 or contact them at www.sec.gov for further information on the public reference room. Encana s filings are also electronically available from the SEC s Electronic Document Gathering, Analysis, and Retrieval system (EDGAR), which can be accessed at www.sec.gov, or via the System for Electronic Document Analysis and Retrieval (SEDAR), which can be accessed at www.sedar.com, as well as from commercial document retrieval services.

Copies of this Annual Report on Form 10-K and the documents incorporated herein by reference may be obtained on request without charge from Encana s Corporate Secretary, 4400, 500 Centre Street S.E., P.O. Box 2850, Calgary, Alberta T2P 2S5, Canada, telephone: (403) 645-2000. Encana also provides access without charge to all of the Company s SEC filings, including copies of this Annual Report on Form 10-K and the documents incorporated herein by reference, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after filing or furnishing, on Encana s website located at www.encana.com.

Enforceability of Civil Liabilities

Encana is a corporation incorporated under and governed by the CBCA. Some of Encana s officers and directors, and some of the experts named in this Annual Report on Form 10-K, are Canadian residents, and many of Encana s assets or the assets of its officers and directors and the experts are located outside the United States. Encana has appointed an agent for service of process in the United States, but it may be difficult for holders of common shares who reside in the United States to effect service within the United States upon those directors, officers and experts who are not residents of the United States. It may also be difficult for holders of common shares who reside in the United States to realize in the United States upon judgments of courts of the United States predicated upon our civil liability and the civil liability of our officers and directors and experts under the United States federal securities laws.

STRATEGY

Encana s vision is to be a leading North American resource play company that is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. Objectives that support the execution of the Company s strategy include:

- Disciplined capital allocation strategy to core assets
- Focused investment on growing high margin liquids volumes
- Maximizing profitability through operational and capital efficiencies
- Preserving balance sheet strength

The Company has a history of identifying and entering into strategic plays that can be developed with industry leading horizontal drilling and completions methods and leveraging technology to profitably develop oil and natural gas resources within the plays. Encana continually strives to lower costs and improve efficiencies to achieve competitive advantage through

Table of Contents

technology and innovation. Capital and operating efficiencies are achieved by repeating and deploying successful practices across the Company s multi-basin portfolio.

Encana s capital investment strategy is focused on quality growth from a limited number of core, high margin and scalable projects, while balancing the commodity portfolio and optimizing performance from the remainder of the Company s resource base. In addition, Encana leverages its market fundamentals expertise by actively monitoring and managing market volatility and diversifying price and market access risks to enhance the Company s margins.

During 2017, the oil and natural gas industry continued to experience commodity price volatility. In spite of this trend, Encana has continued to execute on its strategy by focusing capital investment to core assets with high margin liquids and future growth potential and divesting of non-strategic assets. Moreover, the Company focused on lowering overhead costs and enhancing capital and operating efficiencies by leveraging technology and innovation to maximize efficiencies and results. Encana also focused on reducing costs by leveraging its integrated supply chain model by self-sourcing key drilling and completions consumables to obtain scale advantages from negotiating better contract pricing as well as security of supply services. Through continued execution of its strategy, Encana is well positioned for growth in the current price environment. For additional discussion on the Company s results, see Item 7 of this Annual Report on Form 10-K.

REPORTING SEGMENTS

Encana s predominant operations are focused on the finding and development of oil, NGL and natural gas reserves. The Company is also focused on creating and capturing additional value through its market optimization segment. The Company conducts a substantial portion of its business through subsidiaries. Encana s operating and reportable segments are: (i) Canadian Operations; (ii) USA Operations; and (iii) Market Optimization.

- **Canadian Operations** includes the exploration for, development of, and production of oil, NGLs, natural gas and other related activities within Canada. Core assets that are part of Encana s strategic development focus include: Montney in northeast British Columbia and northwest Alberta and Duvernay in west central Alberta. Other Upstream Operations comprise assets that are not part of Encana s current strategic focus and primarily include: Wheatland in southern Alberta, Horn River in northeast British Columbia and Deep Panuke located offshore Nova Scotia.

- **USA Operations** includes the exploration for, development of, and production of oil, NGLs, natural gas and other related activities within the U.S. Core assets that are part of Encana s strategic development focus include: Eagle Ford in south Texas and Permian in west Texas. Other Upstream Operations comprise assets that are not part of Encana s current strategic focus and primarily includes San Juan in northwest New Mexico.

- **Market Optimization** activities are managed by the Midstream, Marketing & Fundamentals team, which is primarily responsible for the sale of the Company s proprietary production to third party customers and enhancing the associated netback price. Market Optimization activities also include third party purchases and sales of product to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification.

For additional information regarding Encana s reporting segments, see Note 2 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

Table of Contents

OIL AND GAS PROPERTIES AND ACTIVITIES

The following map outlines the location of Encana s North American landholdings and assets as at December 31, 2017.

The term Core Asset in the map above reflects plays identified with high growth and return potential and are the focus of the Company s current capital investment and development plan. The term Other in the map above reflects base and option value plays that are not part of Encana s current strategic focus. Base plays are managed to generate cash flows and focus on enhancing operational efficiency and cost reductions rather than development programs. Option value plays may receive funding for exploration or development based on strategic fit, play profitability driven by price and energy fundamentals and portfolio diversity.

Table of Contents

Canadian Operations

Overview: In 2017, the Canadian Operations had total capital investment of approximately $426 million and drilled approximately 117 net wells all of which were in Montney and Duvernay. Production averaged approximately 29.5 Mbbls/d of oil and NGLs and approximately 838 MMcf/d of natural gas. At December 31, 2017, the Canadian Operations had an established land position in Canada of approximately 1.7 million net acres including approximately 1.2 million net undeveloped acres. In addition, the Canadian Operations accounted for 38% of production sales during 2017 and 59% of total proved reserves as at December 31, 2017.

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, 2017)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Montney	560	357	718	451	1,278	808	63%
Duvernay	105	44	541	330	646	374	58%
Other Upstream Operations [1]	229	157	622	381	851	538	63%
Total Canadian Operations	**894**	**558**	**1,881**	**1,162**	**2,775**	**1,720**	**62%**

(1) Other Upstream Operations includes Wheatland, Horn River and Deep Panuke.

Producing Wells

	Oil		**Natural Gas**		**Total**	
(number of wells at December 31, 2017) [1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Montney	6	5	1,282	1,173	1,288	1,178
Duvernay	11	4	156	78	167	82
Other Upstream Operations [2]	18	12	609	505	627	517
Total Canadian Operations	**35**	**21**	**2,047**	**1,756**	**2,082**	**1,777**

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

(2) Other Upstream Operations includes Wheatland, Horn River and Deep Panuke.

Production	**Oil** (Mbbls/d)		**Plant Condensate** (Mbbls/d)		**NGLs Other** (Mbbls/d)		**Total** (Mbbls/d)		**Natural Gas** (MMcf/d)	
(average daily)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Montney [1]	0.2	1.9	14.6	10.4	4.5	6.2	19.1	16.6	644	735

Duvernay	0.2	-	8.3	7.1	1.3	1.2	9.6	8.3	64	54
Other Upstream Operations [2]	-	0.1	0.2	0.1	0.2	0.2	0.4	0.3	130	177
Total Canadian Operations	**0.4**	**2.0**	**23.1**	**17.6**	**6.0**	**7.6**	**29.1**	**25.2**	**838**	**966**

(1) During 2016, Encana divested of the Gordondale assets in Montney. Prior to the disposition, production from Gordondale averaged 1.6 Mbbls/d of oil, 3.7 Mbbls/d of NGLs and 45 MMcf/d of natural gas.
(2) Other Upstream Operations includes Wheatland, Horn River and Deep Panuke.

Montney

Montney is primarily a condensate rich natural gas play located in northeast British Columbia and northwest Alberta. While Encana is currently targeting the development of condensate rich locations in the Montney formation, the acreage comprising the Montney play also includes landholdings with incremental producing formations such as Cadomin and Doig. In 2017, total production from the play averaged approximately 19.3 Mbbls/d of oil and NGLs and approximately 644 MMcf/d of natural gas. As at December 31, 2017, Encana controlled approximately 808,000 net acres in the play.

During 2017, Encana continued to focus development in the Montney formation, which is characterized by up to six stacked horizons spanning over 1,000 feet of stratigraphy and is being developed exclusively with horizontal well technology. At December 31, 2017, Encana held a large position in the Montney formation of approximately 475,000 net acres, including 259,000 net undeveloped acres and production averaged approximately 19.1 Mbbls/d of oil and NGLs and approximately 567 MMcf/d of natural gas.

Table of Contents

Significant efficiency improvements with respect to Montney drilling and completions have been achieved using the cube development approach. In addition to utilizing larger multi-well pads and simultaneous use of multiple drilling rigs, Encana also focused on tighter well spacing, increased completions intensity and reducing costs. In 2017, Encana drilled approximately 108 net horizontal wells with lateral lengths ranging from approximately 3,200 to 12,800 feet and tighter inter-well spacing ranging from approximately 490 to 880 feet. As Encana continues to optimize well and completion designs, lateral lengths drilled, stage and well spacing may change. The Company also continued to focus on reducing water costs through its centralized water hub by re-using produced water from drilling operations and utilizing otherwise unusable saline water from a subsurface water aquifer.

As at December 31, 2017, Encana has access to natural gas processing capacity of approximately 1,200 MMcf/d, of which approximately 1,000 MMcf/d is under contract with third parties under varying terms and duration and approximately 215 MMcf/d is owned by the Company. Encana also has access to gathering and compression capacity of approximately 1,300 MMcf/d, of which approximately 1,200 MMcf/d is under contract with third parties under varying terms and duration and approximately 100 MMcf/d is owned by the Company. During the fourth quarter of 2017, access to liquids handling capacity increased due to three new facilities that provide compression and processing under contract with third parties.

Encana has a partnership agreement with a subsidiary of Mitsubishi Corporation (Mitsubishi), the Cutbank Ridge Partnership (CRP), to jointly develop certain lands predominately in Montney. Under the agreement, Mitsubishi agreed to invest approximately C$2.9 billion for its 40 percent partnership interest in the CRP, of which approximately C$2.5 billion has been received as of December 31, 2017. In addition to its 40 percent of the CRP s future capital funding investment, Mitsubishi is expected to invest the remaining amount of approximately C$0.4 billion under an agreed upon five-year development plan of the area, thereby reducing Encana s capital funding commitment to 30 percent of the total expected capital investment until the remaining investment commitment is satisfied.

Duvernay

Duvernay is a liquids rich shale gas play located in west central Alberta and includes properties that are primarily located in the Duvernay formation, but also holds potential in other overlapping formations such as the Montney. As at December 31, 2017, Encana controlled approximately 374,000 net acres in the play.

The Duvernay formation within the play primarily comprises approximately 332,000 net acres, including 290,000 net undeveloped acres, and extends across the Simonette, Pinto, Edson and Willesden Green properties. Encana is currently targeting the development of condensate rich locations in the north and south Simonette areas of the formation using multi-well pad horizontal drilling technology. During 2017, Encana focused on efficient development to fill existing processing capacity, reducing drilling days and leveraging successful advanced completions designs to maximize well productivity. Encana also drilled approximately 9 net wells during the year with lateral lengths ranging from approximately 6,400 to 10,800 feet with inter-well spacing averaging approximately 1,000 feet. As Encana continues to optimize well and completion designs, lateral lengths drilled, stage and well spacing may change. In 2017, production averaged approximately 9.8 Mbbls/d of oil and NGLs and approximately 64 MMcf/d of natural gas. In addition, Encana focused on reducing operating costs by approximately 15 percent since 2016 primarily from the automation and centralized monitoring of wells and facilities and lowering of water handling costs by utilizing existing infrastructure to dispose of water to plant site disposal wells, eliminating costs to truck disposal water to third party disposal sites.

Encana holds an approximate 50.1 percent ownership in three Simonette natural gas processing plants and the associated gathering and compression, of which Encana s share of natural gas processing capacity is approximately 90

MMcf/d with NGLs production capacity of approximately 18.0 Mbbls/d.

Encana has an agreement with a subsidiary of PetroChina Company Limited (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, of which the investment was substantially received as of December 31, 2017. In February 2018, Encana received the final investment from PetroChina, satisfying the commitment under the agreement.

Other Upstream Operations:

Wheatland

Wheatland is located in southern Alberta and includes producing horizons primarily in the coals and sands of the Cretaceous Edmonton and Belly River Groups. In the fourth quarter of 2017, Encana divested of approximately 511,000 net acres and approximately 4,720 net wells in the play. As at December 31, 2017, Encana had approximately 525 gross producing wells (approximately 464 net producing wells) and controlled approximately 207,000 net acres in the play. During 2017, Encana

Table of Contents

focused on play optimization, reducing production declines and lowering operating costs. In 2017, natural gas production from the remaining properties averaged approximately 6 MMcf/d.

Horn River

Horn River is located in northeast British Columbia, where development was historically in the Horn River Basin shales (Muskwa, Otter Park and Evie), which are upwards of 500 feet thick. In 2017, Encana s natural gas production averaged approximately 49 MMcf/d. As at December 31, 2017, Encana had approximately 97 gross producing horizontal wells (49 net producing horizontal wells) and controlled approximately 164,000 net acres, which includes 143,000 net undeveloped acres in the Horn River Basin shales. Encana owns an interest in natural gas compression capacity in Horn River of approximately 285 MMcf/d at various facilities in the area. Encana has a processing arrangement with a third party related to a previously planned expansion of the Cabin natural gas processing plant, for which commissioning and expansion was suspended in 2012.

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). 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 northeastern U.S.

In 2017, natural gas production averaged approximately 19 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, under a seasonal operating strategy. At December 31, 2017, Encana had approximately 4 gross producing wells (4 net producing wells) and controlled approximately 30,000 net acres offshore Nova Scotia. Encana operates five of its six licenses in these areas.

Table of Contents

USA Operations

Overview: In 2017, the USA Operations had total capital investment of approximately $1,358 million and drilled approximately 168 net wells. Production averaged approximately 75.9 Mbbls/d of oil, approximately 23.7 Mbbls/d of NGLs and approximately 266 MMcf/d of natural gas. At December 31, 2017, the USA Operations had an established land position of approximately 399,000 net acres including approximately 119,000 net undeveloped acres. In addition, the USA Operations accounted for 62% of production sales during 2017 and 41% of total proved reserves as at December 31, 2017.

During 2017, Encana divested of approximately 550,000 net acres in Piceance located in northwestern Colorado for proceeds of approximately $605 million, after closing adjustments and the sale of approximately 144,000 net acres in Tuscaloosa Marine Shale (TMS) located in east Louisiana and west Mississippi.

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

Landholdings	**Developed**		**Undeveloped**		**Total**		
	Acreage		**Acreage**		**Acreage**		**Average Working**
(thousands of acres at December 31, 2017)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Eagle Ford	44	42	1	1	45	43	96%
Permian	97	86	44	32	141	118	84%
Other Upstream Operations [1]	251	152	153	86	404	238	59%
Total USA Operations	**392**	**280**	**198**	**119**	**590**	**399**	68%

(1) Other Upstream Operations primarily includes San Juan.

Producing Wells

	Oil		**Natural Gas**		**Total**	
(number of wells at December 31, 2017) [1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Eagle Ford	424	411	59	55	483	466
Permian	1,645	1,541	-	-	1,645	1,541
Other Upstream Operations [2]	119	68	259	179	378	247
Total USA Operations	**2,188**	**2,020**	**318**	**234**	**2,506**	**2,254**

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

(2) Other Upstream Operations primarily includes San Juan.

Production	**Oil**	**NGLs** **Plant Condensate**	**NGLs** **Other**	**Total**	**Natural Gas**
		(Mbbls/d)			

	(Mbbls/d)				(Mbbls/d)		(Mbbls/d)		(MMcf/d)	
(average daily)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Eagle Ford	30.8	32.4	1.4	0.6	6.8	6.6	8.2	7.2	51	48
Permian	41.4	29.8	1.5	1.1	12.1	8.9	13.6	10.0	67	50
Other Upstream Operations [1, 2]	3.7	9.5	0.3	1.0	1.6	5.0	1.9	6.0	148	319
Total USA Operations	**75.9**	**71.7**	**3.2**	**2.7**	**20.5**	**20.5**	**23.7**	**23.2**	**266**	**417**

(1) Other Upstream Operations primarily includes San Juan.

(2) Other Upstream Operations includes production from Piceance and TMS which were divested in 2017 and from DJ Basin which was divested in 2016.

Eagle Ford

Eagle Ford is a tight oil play located in south Texas in the Karnes and Atascosa counties. The focus is on the development of the thickest portion of the Eagle Ford shale in the Karnes Trough, where Encana holds a largely contiguous position. At December 31, 2017, Encana controlled approximately 43,000 net acres in the play. Encana is focused on developing the lower Eagle Ford exclusively using horizontal drilling, as well as optimizing upper Eagle Ford and Austin Chalk targets. During 2017, Encana drilled approximately 37 net wells in the area with lateral lengths ranging from approximately 2,600 to 6,800 feet with an average measured total depth of approximately 16,700 feet. Production averaged approximately 30.8 Mbbls/d of oil, approximately 8.2 Mbbls/d of NGLs and approximately 51 MMcf/d of natural gas during the year.

During 2017, Encana continued to focus on precision well targeting, spacing and stacking optimization and improving completions designs. Performance improvements were achieved from optimizing fracture complexity by driving down stage spacing and cluster spacing to less than 20 feet, while optimizing cluster efficiency through thin fluids design, resulting in

Table of Contents

increased well productivity and optimized capital efficiency. In addition, Encana expanded development activity in the Austin Chalk, drilling 12 net horizontal wells in 2017. As Encana continues to optimize development and apply advanced completions designs, lateral lengths drilled, cluster spacing and well spacing may change. Encana also focused on reducing operating costs by negotiating better contract pricing, optimizing artificial lift systems and streamlining well interventions.

The play is located within close proximity to markets and has a well-developed infrastructure. Oil and natural gas production is gathered at various 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 access to firm natural gas gathering capacity of up to approximately 52 MMcf/d and firm processing capacity of up to approximately 72 MMcf/d with third parties under varying terms and duration. Encana utilizes interruptible capacity arrangements for excess production.

Permian

Permian is a tight oil play located in west Texas in the Midland, Martin, Howard, Glasscock and Upton counties. The primary focus is on the development of the Spraberry and Wolfcamp formations in the Midland basin, where Encana holds a large position. At December 31, 2017, Encana controlled approximately 118,000 net acres in the play. The properties are characterized by exposure of up to 11 potential producing horizons spanning approximately 4,000 feet of stratigraphy (also referred to as stacked pay), an extensive production history and mature infrastructure. In 2017, production averaged approximately 41.4 Mbbls/d of oil, approximately 13.6 Mbbls/d of NGLs and approximately 67 MMcf/d of natural gas.

During 2017, Encana focused on maximizing efficiency improvements at an industrial scale and maximizing resource recovery by accessing layers of the stacked pay simultaneously using the cube development approach. This approach utilizes large multi-well pads, multi- rig spreads and frac spreads running in parallel to optimize cycle times, increase capital efficiency and reduce costs through economies of scale from higher utilization of services and consumable supplies, while minimizing the development or surface footprint. Encana also reduced capital costs through centralized wellsite facilities and water infrastructure. Encana also focused on increasing well productivity by optimizing completions designs, with precision targeting of the wells drilled, tighter cluster spacing and using cleaner and thinner fluids to maximize fracture complexity. During 2017, Encana drilled 126 horizontal net wells with lateral lengths ranging from approximately 4,200 to 11,000 feet at a measured average total depth of approximately 17,300 feet with well spacing ranging from approximately 360 to 660 feet. As Encana continues to optimize well and completion designs, lateral lengths drilled, stage and well spacing may change.

Oil and natural gas facilities include field gathering systems, storage batteries, saltwater disposal systems, separation equipment and pumping units. The majority of Encana s acreage and associated oil production is dedicated to a pipeline gathering agreement, which has a total remaining term of 12 years including optional renewal terms. In the event of pipeline capacity constraints, Encana s oil production is trucked by a third party. Natural gas is delivered by Encana to the purchaser s meter and pipeline interconnection point in the field.

Other Upstream Operations:

San Juan

San Juan is a light sweet oil play located in the San Juan Basin in northwest New Mexico where Encana has its land position almost exclusively in the oil window of the play. Development is focused on the liquids in Tocito and El Vado formations within the play. At December 31, 2017, Encana controlled approximately 198,000 net acres in the

play, which includes 69,000 net undeveloped acres. During 2017, Encana drilled 3 horizontal net wells in the Tocito and 1 horizontal net wells in El Vado with lateral lengths ranging from approximately 3,600 to 7,900 feet at a measured average total depth of approximately 12,300 feet. In 2017, Encana applied successful drilling and completions strategies from its other plays, drilling the wells in a transverse orientation utilizing thinner fluids and tighter cluster spacing to optimize fracture complexity. Encana is currently evaluating the stacked pay potential and future well inventory of the play from the well spacing trial. Production averaged approximately 3.9 Mbbls/d of oil and NGLs and approximately 9 MMcf/d of natural gas during the year. Encana has access to natural gas processing capacity of up to approximately 50 MMcf/d under a dedication agreement with a third party.

Table of Contents

PROVED RESERVES AND OTHER OIL AND GAS INFORMATION

The process of estimating oil, NGL and natural gas reserves is complex and requires significant judgment. Encana s estimates of proved reserves and associated future net cash flows were evaluated and prepared by the Company s qualified reserves evaluators (QREs) and are the responsibility of management. As a result, Encana has developed internal policies that prescribe procedures and standards to be followed for preparing, estimating and recording reserves in compliance with SEC definitions and regulations. Encana s policies assign responsibilities for compliance in booking reserves and require that reserve estimates be made by its QREs. QRE is defined as a registered professional licensed to practice engineering, geology, geophysics and an individual who has a minimum of five years practical experience, with at least three recent years of experience in the evaluation of reserves.

Encana s Vice-President, Corporate Reserves and Chief Reservoir Engineering and nine other staff (collectively, the Corporate Reserves Group) under this individual s direction, oversee the internal preparation, review and approval of the reserves estimates. The Corporate Reserves Group reports to the Executive Vice-President, Exploration and Business Development and is separate and independent from the preparation of reserves estimates which are within operations who report to Encana s Executive Vice-President & Chief Operating Officer. The Corporate Reserves Group maintains Encana s internal policies that prescribe procedures and standards to be followed for preparing, estimating and recording reserves, which includes updating the Company s reserves manual, and also conducts periodic internal audits of the procedures, records and controls relating to the preparation of reserves estimates. Encana s QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the review of the Company s reserves manual and internal training programs administered by the Corporate Reserves Group. The Corporate Reserves Group also oversees the engagement of independent qualified reserves evaluators (IQREs) or independent qualified reserves auditors (IQRAs), if any, retained by the Company.

As a member of the Corporate Reserves Group, the Company s Director, Corporate Reserves reports to Encana s Vice-President, Corporate Reserves and Chief Reservoir Engineering and is primarily responsible for overseeing the preparation of proved reserves estimates. The Director, Corporate Reserves has a Bachelor of Science with a degree in Petroleum Engineering from the University of Alberta, is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the Society of Petroleum Evaluation Engineers (Calgary Chapter).

Annually, each play is reviewed in detail by the QREs, the Corporate Reserves Group, the Company s executive officers and an internal Reserves Review Committee, as appropriate. The Corporate Reserves Group also conducts a separate review to ensure the effectiveness of the disclosure controls and that the reserves estimates are free from material misstatement. The final reserves estimates are reviewed by Encana s Reserves Committee of the Board of Directors (the Reserves Committee), for approval by the Board of Directors. The Reserves Committee comprises directors that are independent and familiar with estimating oil and gas reserves and disclosure requirements. The Reserves Committee provides additional oversight to the Company s reserves process, meeting with management periodically to review the reserves process, the portfolio of properties results and related disclosures. The Reserves Committee is also responsible for reviewing the qualifications and appointment of IQREs or IQRAs, if any, retained by the Company, including recommending the selection of such IQREs or IQRAs to the Board of Directors for its approval, and will meet with such IQREs or IQRAs to review their reports.

For year-ended December 31, 2017, Encana involved IQRAs to audit and review the processes relating to the Company s internal oil and gas reserve estimates for certain properties. In 2017, McDaniel & Associates Consultants Ltd. audited 75 percent of Encana s estimated Canadian proved reserves volumes and Netherland, Sewell & Associates, Inc. audited 80 percent of Encana s estimated U.S. proved reserves volumes. An audit of reserves is an examination of a company s oil and gas reserves and future net cash flows by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and

have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation methods and procedures.

Proved oil and gas reserves are those quantities of oil, gas and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. To be considered proved, oil and gas reserves must be economically producible before contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Also, the project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

Table of Contents

The Company s reserve estimates are conducted from fundamental petrophysical, geological, engineering, financial and accounting data. Reserves are estimated based on production decline analysis, analogy to producing offsets, detailed reservoir modeling, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations and using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in assessments include information obtained directly from the subsurface through wellbores such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. 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. The tools used to interpret the data included proprietary and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir are based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development, and operating expenditures with respect to the reserves associated with the Company s properties may vary from the information presented herein, and such variations could be material.

The SEC regulations require that proved reserves be estimated using existing economic conditions (constant pricing). Based on this methodology, Encana s reserves have been calculated utilizing the 12-month average trailing historical price for each of the years presented prior to the effective date of the report. The 12-month average is calculated as an unweighted average of the first-day-of-the-month price for each month. The reserves estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

Encana does not file any estimates of total net proved reserves with any U.S. federal authority or agency other than the SEC and the Department of Energy (DOE). Reserve estimates filed with the SEC correspond with the estimates of the Company s reserves contained in its reports. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of Encana s reserves that are filed with the SEC, however, the DOE requires reports to include the interests of all owners in wells that Encana operates and to exclude all interests in wells that Encana does not operate. Encana is also 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) which is filed concurrently on SEDAR at www.sedar.com under Encana s issuer profile. The primary differences between NI 51-101 reporting requirements and SEC requirements include the disclosure of proved and probable reserves estimated using forecast prices and costs, presentation of reserves and production before royalties and granular product type disclosures. The reserves data prepared in accordance in NI 51-101 do not form part of this Annual Report on Form 10-K.

The reserves and other oil and gas information set forth below has an effective date of December 31, 2017 and was prepared as of January 15, 2018. The audit reports prepared by the IQRA s are attached in Exhibits 99.1 and 99.2 of this Annual Report on Form 10-K.

The following table is a summary of the Company s proved reserves and estimates of future net cash flows and discounted future net cash flows from proved reserves information relating to proved reserves which can also be found in Note 25 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

Table of Contents

Proved Reserves

The table below summarizes the Company s total proved reserves by natural gas, oil and NGLs and by geographic area as at December 31, 2017 and other summary operating data.

As at December 31, 2017

	Canada	U.S.	Total
Proved Reserves:[1]			
Oil (MMbbls):			
Developed	0.2	104.7	104.9
Undeveloped	-	87.7	87.7
Total	0.2	192.3	192.5
Natural Gas Liquids (MMbbls):			
Developed	40.5	41.6	82.1
Undeveloped	74.5	25.8	100.3
Total	115.0	67.5	182.5
Natural Gas (Bcf):			
Developed	1,082	243	1,325
Undeveloped	1,053	141	1,195
Total	2,135	384	2,519
Total Proved Reserves (MMBOE):			
Developed	221.0	186.8	407.8
Undeveloped	250.0	137.0	387.1
Total	471.0	323.9	794.9
Percent Proved Developed	47%	58%	51%
Percent Proved Undeveloped	53%	42%	49%
Production (MBOE/d)	169.1	144.1	313.2
Capital Investments (millions)	$ 426	$1,358	$1,784
Total Net Producing Wells [2]	1,835	2,339	4,174
Standardized Measure of Discounted Net Cash Flows: [3]			
Pre-Tax (millions)	$1,635	$2,731	$4,366

Taxes (millions)	53	-	53
After-Tax (millions)	$1,582	$2,731	$4,313

(1) Numbers may not add due to rounding.
(2) Total net producing wells includes producing wells and wells mechanically capable of production.
(3) The Pre-Tax standardized measure of discounted cash flows (standardized measure) is a non-GAAP measure. The Company believes the Pre-Tax standardized measure is a useful measure in addition to the After-Tax standardized measure, as it assists in both the estimation of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The After-Tax standardized measure is dependent on the unique tax situation of each individual company, while the Pre-Tax standardized measure is based on prices and discount factors, which are more consistent between peer companies. See Note 25 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K for the standardized measure.

Changes to the Company s proved reserves during 2017 are summarized in the table below:

	2017			
	Oil	**NGLs**	**Natural Gas**	**Total**
	(MMbbls)	(MMbbls)	(Bcf)	(MMBOE)
Beginning of year [1]	155.6	150.4	2,902	789.7
Revisions and improved recovery [2]	(15.8)	(18.1)	(58)	(43.6)
Extensions and discoveries	85.1	72.9	871	303.1
Purchase of reserves in place	0.8	0.4	2	1.5
Sale of reserves in place	(5.4)	(3.8)	(795)	(141.6)
Production	(27.8)	(19.3)	(403)	(114.3)
End of year	192.5	182.5	2,519	794.9
Developed	104.9	82.1	1,325	407.8
Undeveloped	87.7	100.3	1,195	387.1
Total	192.5	182.5	2,519	794.9

(1) Numbers may not add due to rounding.
(2) Changes in reserve estimates resulting from application of improved recovery techniques are nil and are included in revisions of previous estimates.

Table of Contents

In 2017, Encana s proved oil and NGLs reserves of 375.0 MMbbls increased 69.0 MMbbls from 2016 primarily due to extensions and discoveries of 158.0 MMbbls in the Permian, Montney, and Eagle Ford and purchase of reserves in place of 1.2 MMbbls, partly offset by production of 47.1 MMbbls, negative revisions and improved recovery of 33.9 MMbbls and by sale of reserves of 9.2 MMbbls. Revisions and improved recovery of oil and NGLs were negative primarily due to negative revisions resulting from changes in the approved development plan of 40.3 MMbbls and forecast changes resulting from well performance of 7.7 MMbbls, partly offset by positive revisions of 14.0 MMbbls from higher 12-month average trailing oil and NGL prices.

In 2017, Encana s proved natural gas reserves of approximately 2,519 Bcf decreased 383 Bcf from 2016 primarily due to sales of reserves in place of 795 Bcf resulting from the divestiture of the Piceance natural gas play and production of 403 Bcf. Revisions and improved recovery of natural gas were negative primarily due to negative revisions of 258 Bcf resulting from changes in the approved development plan, partly offset by positive revisions of 111 Bcf from higher 12-month average trailing natural gas prices and by positive forecast changes other than price of 89 Bcf. Extensions and discoveries of 871 Bcf were due to successful drilling and delineation of Permian, Montney and Eagle Ford assets.

Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2017 were WTI: $51.34 per bbl, Edmonton Condensate: C$67.65 per bbl, Henry Hub: $2.98 per MMBtu, and AECO: C$2.32 per MMBtu. Prices for natural gas, oil and NGLs can fluctuate widely.

Proved Undeveloped Reserves

Changes to the Company s proved undeveloped reserves during 2017 are summarized in the table below:

(MMBOE)	**2017**
Beginning of year	341.0
Revisions of prior estimates	(98.7)
Extensions and discoveries	225.7
Conversions to developed	(82.4)
Purchase of reserves in place	1.5
Sale of reserves in place	-
End of Year	**387.1**

* Numbers may not add due to rounding.

As of December 31, 2017, there were no proved undeveloped reserves that will remain undeveloped for five years or more.

Revisions of previous estimates of proved undeveloped reserves were revised down by 98.7 MMBOE primarily due to the removal of proved undeveloped locations of 83.3 MMBOE resulting from changes in the development plan related to Montney, Permian, Eagle Ford, and San Juan where specific locations previously planned to be drilled within five years were shifted to a later development timeframe and replaced with different locations that are included in extensions and discoveries. In addition, revisions of previous estimates also included a negative revision of 17.4 MMBOE from decreased well performance, offset by a positive revision of 2.0 MMBOE due to higher commodity prices.

Conversions of proved undeveloped reserves to proved developed status were 82.4 MMBOE, equating to 24 percent of the total prior year-end proved undeveloped reserves. Approximately 70 percent of proved undeveloped reserves conversions occurred in Canada in Montney and Duvernay and 30 percent occurred in the U.S. in Permian and Eagle Ford. Encana spent approximately $427 million to develop proved undeveloped reserves in 2017, of which approximately 40 percent related to the Canadian properties and 60 percent related to the U.S. properties.

Purchases of proved undeveloped reserves of 1.5 MMBOE relate to acquisitions in the Eagle Ford and Permian.

Table of Contents

Sales Volumes, Prices and Production Costs

The following table summarizes the Company s production by final product sold, average sales price, and production cost per BOE for each of the last three years by geographic area:

	Production			Average Sales Price[1]			Average Production Cost[2]
	Oil	NGLs	Natural Gas	Oil	NGLs	Natural Gas	
	(MMbbls)	(MMbbls)	(Bcf)	($/bbl)	($/bbl)	($/Mcf)	($/BOE)
2017							
Canada [3]	0.1	10.6	306	42.33	45.35	2.16	11.46
USA	27.7	8.7	97	49.14	22.30	3.03	9.42
Total	27.8	19.3	403	49.10	34.98	2.37	10.52
2016 [4]							
Canada	0.7	9.2	353	36.32	32.32	1.77	10.69
USA	26.3	8.5	153	38.67	14.86	2.29	10.89
Total	27.0	17.7	506	38.61	23.94	1.93	10.78
2015 [4]							
Canada	2.0	8.3	354	43.90	29.21	2.75	11.74
USA	29.8	8.6	242	43.31	14.37	2.60	13.96
Total	31.8	16.9	596	43.35	21.66	2.69	12.92

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem, severance and property taxes.
(3) Annual production from fields that comprise greater than 15% of the Company s total proved reserves as at December 31, 2017 related to Dawson North in Montney and included 81 Bcf of natural gas (2016 89 Bcf; 2015 67 Bcf) and 2.3 MMbbls of NGLs (2016 1.3 MMbbls; 2015 0.9 MMbbls).
(4) Encana had no fields where annual production comprised greater than 15% of the Company s total proved reserves for the periods ended December 31, 2016 and December 31, 2015.

The following table summarizes the Company s revenues by product sold and by geographic area for each of the last three years:

	Net Production Sales					Total Revenue
($ millions)	Oil	NGLs	Natural Gas	Other Revenue[1]	Gains (losses) on risk management, net	
2017						
Canada	$ 7	$ 481	$ 662	$ 189	$ 522	$ 1,861
USA	1,360	193	296	773	(40)	2,582

Total	$ 1,367	$ 674	$ 958	$ 962	$ 482	$ 4,443
2016						
Canada	$ 26	$ 298	$ 628	$ 166	$ (151)	$ 967
USA	1,015	126	350	584	(124)	1,951
Total	$ 1,041	$ 424	$ 978	$ 750	$ (275)	$ 2,918
2015						
Canada	$ 90	$ 243	$ 976	$ 222	$ 166	$ 1,697
USA	1,288	124	629	258	426	2,725
Total	$ 1,378	$ 367	$ 1,605	$ 480	$ 592	$ 4,422

(1) Includes market optimization and other revenues such as purchased product sold to third parties, sublease revenues and gathering and processing services provided to third parties.

Table of Contents

Drilling and other exploratory and development activities [1, 2]

The following tables summarize Encana s gross participation and net interest in wells drilled for the periods indicated by geographic area.

	Exploratory				Development				Total			
	Productive		Dry		Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2017												
Canada	2	1	-	-	189	116	-	-	191	117	-	-
USA	-	-	-	-	183	168	-	-	183	168	-	-
Total	**2**	**1**	**-**	**-**	**372**	**284**	**-**	**-**	**374**	**285**	**-**	**-**
2016												
Canada	1	-	1	-	100	44	3	-	101	44	4	-
USA	3	3	-	-	124	113	-	-	127	116	-	-
Total	**4**	**3**	**1**	**-**	**224**	**157**	**3**	**-**	**228**	**160**	**4**	**-**
2015												
Canada	-	-	1	-	173	135	-	-	173	135	1	-
USA	-	-	-	-	402	265	2	-	402	265	2	-
Total	**-**	**-**	**1**	**-**	**575**	**400**	**2**	**-**	**575**	**400**	**3**	**-**

(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.

Drilling and other exploratory and development activities [1, 2]

The following table summarizes the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion by geographic area at December 31, 2017.

	Wells in the Process of Drilling or in Active Completion				Wells Suspended or Waiting on Completion [3]			
	Exploratory		Development		Exploratory		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2017								
Canada	-	-	19	13	-	-	57	34
USA	-	-	23	23	-	-	11	11
Total	**-**	**-**	**42**	**36**	**-**	**-**	**68**	**45**

(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)

Wells suspended or waiting on completion include exploratory and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

Oil and gas properties, wells, operations, and acreage

The following table summarizes the number of producing wells and wells mechanically capable of production by geographic area at December 31, 2017.

Productive Wells [1, 2]	**Oil** [3]		**Natural Gas** [4]		**Total**	
	Gross	Net	Gross	Net	Gross	Net
2017						
Canada	36	22	2,121	1,813	2,157	1,835
USA	2,234	2,060	367	279	2,601	2,339
Total	**2,270**	**2,082**	**2,488**	**2,092**	**4,758**	**4,174**

(1) Gross wells are the total number of wells in which Encana has an interest.
(2) Net wells are the number of wells obtained by aggregating Encana s working interest in each of its gross wells.
(3) Includes 66 gross oil wells (13 net oil wells) containing multiple completions.
(4) Includes 1,994 gross natural gas wells (1,674 net natural gas wells) containing multiple completions.

Table of Contents

The following table summarizes Encana s developed, undeveloped and total landholdings by geographic area as at December 31, 2017.

Landholdings (1 - 6)		**Developed**		**Undeveloped**		**Total**	
(thousands of acres)		Gross	Net	Gross	Net	Gross	Net
Canada							
Onshore	Crown	815	503	1,605	975	2,420	1,478
	Freehold	58	34	217	172	275	206
	Fee	1	1	3	3	4	4
Offshore	Crown	20	20	56	12	76	32
Total Canada		**894**	**558**	**1,881**	**1,162**	**2,775**	**1,720**
United States							
	Federal/State	235	140	128	80	363	220
	Freehold	156	140	65	38	221	178
	Fee	1	-	5	1	6	1
Total United States		**392**	**280**	**198**	**119**	**590**	**399**
International							
Australia		-	-	104	40	104	40
Total International		**-**	**-**	**104**	**40**	**104**	**40**
Total		**1,286**	**838**	**2,183**	**1,321**	**3,469**	**2,159**

(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 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) Crown/Federal/State lands are those owned by the federal, provincial or state government or First Nations, in which Encana has purchased a working interest lease.
(3) Freehold lands are owned by individuals (other than a government or Encana), in which Encana holds a working interest lease.
(4) Gross acres are the total area of properties in which Encana has an interest.
(5) Net acres are the sum of Encana s fractional interest in gross acres.
(6) 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.

Of the total 2.2 million net acres, approximately 0.8 million net acres is held by production. The table above includes acreage subject to leases that will expire over the next three years: 2018 approximately 78,000 net acres; 2019 approximately 201,000 net acres; and 2020 approximately 192,000 net acres, if the Company does not establish production or take any other action to extend the terms. For acreage that the Company intends to further develop, Encana will perform operational and administrative actions to continue the lease terms that are set to expire. As a result, it is not expected that a significant portion of the Company s net acreage will expire before such actions occur.

Title to Properties

As is customary in the oil and natural gas industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time Encana acquires properties. The Company believes that title to all of the various interests set forth in the above table is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in Encana s operations. The interests owned by Encana may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as production payments, net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in the Company s operations.

Table of Contents

MARKETING ACTIVITIES

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. In marketing production, Encana looks to minimize market related shut-ins, maximize realized prices and manage concentration of credit-risk exposure. Market Optimization activities include third party purchases and sales of product to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification. In conjunction with certain divestitures, Encana has also agreed to market and transport certain portions of the acquirer s production with remaining terms of less than five years.

Encana s produced oil, NGLs and natural gas, are primarily marketed to refiners, local distributing companies, energy marketing companies and electronic exchanges. Prices received by Encana are based primarily upon prevailing market index prices in the region in which it is sold. Prices are impacted by regional and global supply and demand and by competing fuels in such markets.

Encana s oil production is sold under short term and evergreen contracts or under dedication agreements, for which prices received by Encana are based primarily upon the prevailing index prices in the relevant region where the product is sold. Encana s NGLs production is sold under short term and long-term contracts that range up to 11 years, or under dedication arrangements at the relevant market price at the time the product is sold. Encana s natural gas production is sold under short-term delivery contracts with terms less than 2 years in duration, at the relevant monthly or daily market price at the time the product is sold. Natural gas production from Deep Panuke is sold under a dedication agreement with a third party for prevailing market prices in that region.

Encana also seeks to mitigate the market risk associated with future cash flows by entering into various financial risk management contracts relating to produced oil, NGLs and natural gas. Details of contracts related to Encana s various financial risk management positions are found in Note 22 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

The Company enters into various contractual agreements to sell oil, NGLs and natural gas, some of which require the delivery of fixed and determinable quantities. As of December 31, 2017, Encana was committed to deliver approximately 3,600 Mbbls of oil and NGLs and approximately 180,000 MMcf of natural gas in the Canadian Operations and approximately 44,000 MMcf of natural gas in the USA Operations with terms under two years.

Certain transportation and processing commitments result in the following financial commitments:

($ millions)	1 Year	2-3 Years	4-5 Years	> 5 years	Total
Transportation & Processing					
Canadian Operations					
Oil & NGLs	51	137	127	281	596
Natural Gas	406	779	657	1,809	3,651
Total Canadian Operations	457	916	784	2,090	4,247
USA Operations					
Oil & NGLs	3	6	6	17	32
Natural Gas	144	449	310	208	1,111

Total USA Operations	147	455	316	225	1,143
Total Canadian and USA Operations	**604**	**1,371**	**1,100**	**2,315**	**5,390**

In general, Encana expects to fulfill delivery commitments with production from proved developed reserves, with longer term delivery commitments to be filled from the Company s proved undeveloped reserves. Where proved reserves are not sufficient to satisfy the Company s delivery commitments, Encana can and may use spot market purchases to satisfy the respective commitments. In addition, for the Company s long-term transportation and processing agreements, Encana also expects to fulfill delivery commitments from the future development of resources not yet characterized as proved reserves. Likewise, where delivery commitments are not transferred along with property divestitures, Encana may market and transport certain portions of the acquirer s production to meet the delivery requirements.

Table of Contents

In addition, production from the Company s reserves are not subject to any priorities or curtailments that may affect quantities delivered to its customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond the Company s control that may affect Encana s ability to meet contractual obligations other than those discussed in Item 1A. Risk Factors of this Annual Report on Form 10-K.

MAJOR CUSTOMERS

In connection with the marketing and sale of Encana s production and purchased oil, NGLs and natural gas for the year ended December 31, 2017, the Company had two customers, Royal Dutch Shell Group and Flint Hills Resources, which individually accounted for more than 10 percent of Encana s consolidated revenues (2016 and 2015 two customers, Royal Dutch Shell Group and Flint Hills Resources). Encana does not believe that the loss of any single customer would have a material adverse effect on the Company s financial condition or results of operations. Further information on Encana s major customers are found in Note 2 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

COMPETITION

The Company s competitors include national, integrated and independent oil and gas companies, as well as oil and gas marketers and other participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. 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 oil, NGLs and natural gas reserves;
- Reserves and property acquisitions;
- Transportation and marketing of oil, NGLs, natural gas 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 oil, NGLs or natural gas.

EMPLOYEES

At December 31, 2017, Encana employed 2,107 employees as set forth in the following table.

	Employees
Canada	1,157
U.S.	950
Total	2,107

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

ENVIRONMENTAL AND REGULATORY MATTERS

As Encana is an owner or lessee and operator of oil and gas properties and facilities in Canada and the United States, the Company is subject to numerous federal, provincial, state, local, tribal and foreign country laws and regulations

relating to pollution, protection of the environment and the handling 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, remediating damage caused by the use or release of specified substances, and require suspension or cessation of operations in affected areas. The following are significant areas of government control and regulation affecting Encana s operations:

Exploration and Development Activities:

Our operations are subject to federal, tribal, state, provincial and local laws and regulations. These laws and regulations relate to matters that include: acquisition of seismic data; location, drilling and casing of wells; well design; hydraulic

Table of Contents

fracturing; well production; use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the restoration of properties upon which wells have been drilled and facilities have been constructed; plugging and abandoning of wells; transportation of production; and calculation and disbursement of royalty payments and production and other taxes.

The Company s operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells that may be drilled in a unit; the rate of production allowable from oil and gas wells; and the unitization or pooling of oil and gas properties. In addition, conservation laws generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas that can produce from the Company s wells and the number of wells or the locations that can be drilled.

Environmental and Occupational Regulations:

The Company is subject to many federal, state, provincial, local and tribal laws and regulations concerning occupational health and safety as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to:

- the discharge of pollutants into federal, provincial and state waters;
- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials, including hazardous substances;
- the emission of certain gases into the atmosphere;
- the sourcing and disposal of water;
- the protection of endangered species and habitat;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- the development of emergency response and spill contingency plans; and
- employee health and safety.

Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company s activities in a particular area. Although environmental requirements have a substantial impact upon the energy industry as a whole, Encana does not believe that these requirements affect the Company differently, to any material degree, as compared to other companies in the oil and natural gas industry. For further information regarding regulations relating to environmental protection, see Item 1A. Risk Factors of this Annual Report on Form 10-K.

Operating and capital costs incurred to comply with the requirements of these laws and regulations are necessary business costs in the oil and gas industry. As a result, Encana has established policies for continuing compliance with environmental laws and regulations. The Corporate Responsibility, Environment, Health and Safety Committee of the 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 performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. The Company has established operating procedures and training programs designed to limit the environmental impact of the Company s field facilities and identify, communicate and comply with changes in existing laws and regulations. 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. In addition, the Board of Directors is advised of significant contraventions thereof, and receives updates on trends, issues or events which could have a significant impact on the Company.

The Company believes that it is in material compliance with existing environmental and occupational health and safety regulations. Further, the Company believes that the cost of maintaining compliance with these existing laws and regulations will not have a material adverse effect on its business, financial condition or results of operations. In addition, Encana maintains insurance coverage for insurable risks against certain environmental and occupational health and safety risks that is consistent with insurance coverage held by other similarly situated industry participants, but the Company is not fully insured

Table of Contents

against all such risks. However, it is possible that developments, such as new or more stringently applied existing laws and regulations as well as claims for damages to property or persons resulting from the Company s operations, could result in substantial costs and liabilities to the Company. As a result, Encana is unable to predict with any reasonable degree of certainty future exposures concerning such matters.

EXECUTIVE OFFICERS OF THE REGISTRANT

Encana s Executive Officers are set out in the table below:

Name	Age (1)	Years Served as Executive Officer	Corporate Office
Douglas J. Suttles	57	5	President & Chief Executive Officer
Joanne L. Alexander	51	3	Executive Vice-President & General Counsel
Sherri A. Brillon	58	11	Executive Vice-President & Chief Financial Officer
David G. Hill	56	4	Executive Vice-President, Exploration & Business Development
Michael G. McAllister	59	7	Executive Vice-President & Chief Operating Officer
Michael Williams	58	4	Executive Vice-President, Corporate Services
Renee E. Zemljak	53	8	Executive Vice-President, Midstream, Marketing & Fundamentals

(1) As of February 26, 2018

Mr. Suttles was appointed President & Chief Executive Officer in June 2013. Prior to that, Mr. Suttles was an independent businessman performing consulting services in the oil and gas industry and serving on the boards of Ceres, Inc. (a public energy crop company) and NEOS GeoSolutions (a privately held geosciences company) from March 2011 until June 2013. Mr. Suttles was also Chief Operating Officer at BP Exploration & Production from January 2009 until March 2011.

Ms. Alexander was appointed Executive Vice-President & General Counsel in January 2015. Prior to that, 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 (an oil and gas company) from 2007 to 2008.

Ms. Brillon was appointed Executive Vice-President & Chief Financial Officer in November 2009. Ms. Brillon joined one of Encana s predecessor companies in 1985 and assumed a variety of leadership roles, including her previous position as Executive Vice-President, Strategic Planning and Portfolio Management in January 2007. Ms. Brillon served as a director of the Canadian Chamber of Commerce (a not-for-profit company) from 2007 to 2009, as a director of PrairieSky Royalty Ltd. (a public oil and gas royalty company) from April 2014 to September 2014 and as a director of Tim Horton s Inc. (a public restaurant company) from November 2013 to December 2014.

Mr. Hill was appointed Executive Vice-President, Exploration & Business Development in November 2013. Mr. Hill joined Encana in November 2002 and assumed a variety of leadership roles, including his previous position as Vice-President, Natural Gas Economy Operations. Prior to these positions, Mr. Hill was President of TICORA Geosciences (a privately held geosciences company) from 2000 to 2002.

Mr. McAllister was appointed Executive Vice-President & Chief Operating Officer in November 2013. Mr. McAllister joined one of Encana s predecessor companies in June 2000 and assumed a variety of leadership roles, including his previous position as Executive Vice-President & Senior Vice-President, Canadian Division in February 2011. Before joining Encana, Mr. McAllister worked in various technical and leadership roles for Texaco Canada and Imperial Oil Resources.

Mr. Williams was appointed Executive Vice-President, Corporate Services in March 2014. Prior to that, 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.

Ms. Zemljak was appointed Executive Vice-President, Midstream, Marketing & Fundamentals in November 2009. Ms. Zemljak joined one of Encana s predecessor companies in November 2000 and assumed a variety of leadership roles, including her previous position as Vice-President of USA Marketing in May 2002. Prior to joining Encana, Ms. Zemljak worked in various roles for Montana Power (formerly a public power company).

Table of Contents

ITEM 1A. 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 s financial condition.

Encana s financial performance and condition are substantially dependent on the prevailing prices of natural gas, oil and NGLs. Low natural gas, oil or NGLs prices and significant U.S. and Canadian price differentials will 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, transportation and infrastructure constraints, prices and availability of alternate sources of energy (including refined products, coal, and renewable energy initiatives) and by technological advances affecting energy consumption. Oil prices are largely determined by international and domestic supply and demand. Factors which affect oil prices include the actions of the OPEC, 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 could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment or shut-in of 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 the applicable accounting standards. If natural gas, oil or NGLs prices decline further, 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 which may have a material adverse effect on its business, financial condition or results of operations.

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, changes to free trade agreements, including the North American Free Trade Agreement (NAFTA), reliance on industry partners and service providers, unexpected cost increases, royalties, taxes, including the impact of recent U.S. tax reform and potential U.S. Treasury Department regulations and guidance, 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, physical impacts from adverse weather conditions and other natural disasters, the availability and proximity of processing and pipeline capacity, transportation interruptions and constraints, 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

Table of Contents

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 compared to other companies that may have a more geographically diversified portfolio of properties.

Fluctuations in natural gas, oil or NGLs prices can create fiscal challenges for the oil and gas industry. These conditions have impacted companies in the oil and gas industry and the Company s spending and operating plans and may continue to do so in the future. 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 a 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 proved reserves are estimates and any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause quantities and net present value of our reserves to be overstated or understated.

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 Report on Form 10-K and other published reserves and resources data 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 commodity 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 and resources 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.

The estimates of reserves included in this Annual Report on Form 10-K are prepared in accordance with SEC regulations and require, subject to limited exceptions, that proved undeveloped reserves may only be classified as proved reserves if the related wells are scheduled to be drilled within five years after the date of booking. 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. Proved undeveloped reserves may be reclassified to unproved due to delays in the development of reserves, or projects becoming uneconomical due to increases in costs to drill such reserves, or lower future net revenues from further decreases in commodity prices.

Commodity prices used to estimate reserves included in this Annual Report on Form 10-K are calculated as the average oil and natural gas price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. Significant future price changes can have a material effect on the quantity and value of the Company s proved reserves. The standardized measure of discounted future net cash flows included in this Annual Report on Form 10-K will not represent the current market value of Encana s

Table of Contents

estimated reserves. In addition, these reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage.

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 oil, NGLs and natural gas reserves and production, and therefore its cash flows, are highly dependent upon its success in developing 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 core assets which results in a concentration of capital and increased 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.

In addition, Encana s operations utilize horizontal multi-pad drilling, tighter drill spacing and completions techniques that evolve over time as learnings are captured and applied. The use of this technology may increase the risk of unintentional communication with other wells and the potential for acceleration of current reserves or an increase in recovery factor from the reservoir. If drilling and completions results are less than anticipated, the production volumes may be lower than anticipated.

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 and NGLs businesses are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, tribal, 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 availability and management of fresh, potable or brackish 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 as discussed below.

Climate Change - A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases and certain air pollutants. These governments are currently developing regulatory and policy frameworks to deliver on their announcements. The Canadian federal government along with certain provinces and territories, including Alberta and British Columbia, have announced a pan-Canadian climate change framework that is consistent with the outcome reached at the 21st Conference of the Parties in Paris and which includes imposing an economy wide cost on carbon emissions in Canada

Table of Contents

by 2023. The Alberta government outlined its Climate Leadership Plan which includes four key areas, one of which is targeting a 45 percent reduction in methane gas emissions from oil and gas operations by 2025, to be achieved through equipment replacement and leak detection and repair regulations. Both Alberta and British Columbia have implemented a provincial carbon tax; Alberta introduced a carbon levy in January 2017 of C$20 per tonne of CO_2e, increasing to C$30 per tonne of CO_2e in 2018 while British Columbia has an established carbon levy of C$30 per tonne of CO_2e, increasing by C$5 per tonne of CO_2e per year starting April 1, 2018 until it reaches C$50 per tonne of CO_2e in 2021. In the United States, the U.S. Environmental Protection Agency (EPA) has proposed to delay the implementation of rules currently in effect that regulate methane emissions from the oil and gas industry. As part of the proposed delay, the EPA intends to evaluate whether to regulate oil and gas methane emissions directly or as a co-benefit of regulating volatile organic compounds. Encana s cost of complying with emerging climate and cost of carbon regulations is not currently forecast to be material to the Company, however as these and additional federal and regional programs are in their early implementation stage or under development, Encana is unable to predict the total future impact of the potential regulations upon its business. Therefore, it is possible that the Company could face future increases in operating costs in order to comply with legislation governing emissions. Further, certain local governments, stakeholders and other groups have made claims against companies in the oil and gas industry, including the Company, relating to the purported causes and impact of climate change. These claims have, among other things, resulted in litigation, shareholder proposals and local ballot initiatives targeted against certain companies and the oil and gas industry generally. As these claims are in their early stages, the Company is unable to assess the impact of such claims on its business, but the defense of such matters may be costly and time consuming and could have a material adverse effect on the Company s reputation.

Hydraulic Fracturing - The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments continue to review certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. 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 continue to suggest 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.

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 delays, 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 and oil that the Company is ultimately able to produce from its reserves. 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.

As these federal and regional programs are in their early implementation stage or 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 hydraulic fracturing.

Seismic Activity Some areas of North America are experiencing increasing localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas

operations is generally very low, it has been linked to deep disposal of wastewater in the United States and has been correlated with hydraulic fracturing in Western Canada which has prompted legislative and regulatory initiatives intended to address these concerns. These initiatives have the potential to require additional monitoring, restrict the injection of produced water in certain disposal wells and/or modify or curtail hydraulic fracturing operations which could lead to operational delays, increase compliance costs or otherwise adversely impact the Company s operations.

Encana s risk management activities may prevent the Company from fully benefiting from price increases and expose us to other risks.

The nature of the Company s operations results in exposure to fluctuations in commodity prices and foreign currency exchange rates. The Company monitors its exposure to such fluctuations and, where the Company deems it appropriate,

Table of Contents

utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in natural gas, oil or NGLs prices and fluctuations in foreign currency exchange rates.

Under U.S. GAAP, derivative financial 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 risk management agreements and the amount of estimated production hedged 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 risk management agreements fail to fulfill their obligations under the agreements, particularly during periods of declining commodity prices.

Downgrades in Encana s credit ratings 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. One of the Company s credit ratings is below an investment-grade credit rating. There can be no assurance that the Company s other credit ratings will not also be downgraded, including below an investment-grade credit rating.

The Company s borrowing costs and ability to raise funds are directly impacted by its credit ratings. A downgrade may increase the cost of borrowing under the Company s existing credit facilities, limit access to private and public markets to raise short-term and long-term debt, and negatively impact the Company s cost of capital. Further, as a result of one of the Company s credit ratings being below investment grade, access to the Company s U.S. commercial paper program has been eliminated.

Credit ratings may also be important to suppliers or counterparties when they seek to engage in certain transactions. Downgrades in one or more of the Company s credit ratings below investment-grade may require the Company to post collateral, letters of credit, cash or other forms of security as financial assurance of the Company s performance under certain contractual arrangements with marketing counterparties, facility construction contracts, and pipeline and midstream service providers. Additionally, certain of these arrangements contain financial assurance language that may, under certain circumstances, permit the Company s counterparties to request additional collateral.

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 based on 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.

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

As at December 31, 2017, the Company had total long-term debt of $4,197 million and no 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.

Table of Contents

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.

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

The Company s business is subject to 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, loss of well control, surface spills and uncontrolled ground releases of fluids during hydraulic fracturing or other similar activities, and 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 and other natural disasters, spills and migration of hazardous chemicals, pollution and other environmental risks.

The Company has become increasingly dependent upon information technology systems to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial and operating data, analyze seismic and drilling information, and communicate with employees and third-party partners. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to the Company s business activities or its competitive position. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems and are reviewed by the appropriate senior management with oversight from the Company s Board of Directors; however these controls may not adequately prevent cyber-security breaches. There is no assurance that the Company will not suffer losses associated with cyber-security breaches in the future, and the Company may be required to expend significant additional resources to investigate, mitigate and remediate any potential vulnerabilities.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of a significant event against the Company which Encana is not fully insured could have a material adverse effect on the Company s financial position.

Encana is dependent on partners to fund development projects conducted through joint ventures and partnerships, which if such funding is unavailable may adversely affect the Company s operations and financial condition.

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, suspend or terminate such arrangements 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

Table of Contents

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. Further, Encana is involved from time to time in disputes with its partners and, as such, it may be unable to dispose of assets or interests in certain arrangements if such disputes cannot be resolved in a satisfactory or timely manner.

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, type curve performance and 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 or in new or emerging formations. New or emerging formations and areas often have limited or no production history and the Company may be less able to predict future drilling and production results over the life-cycles of the wells in such areas. 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.

The Company may be unable to dispose of certain assets and may be required to retain liabilities for certain matters.

The Company may identify certain assets for disposition, 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 the Board of Directors, associated asset retirement obligations, due diligence, favourable market conditions, the assignability of joint venture, partnership or other arrangements and stock exchange, regulatory and third party approvals. These factors may also reduce the proceeds or value to Encana.

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 decision to pay dividends and the amount of such dividends is subject to the discretion of the 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 vary from time to time and could be increased, 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

Table of Contents

requirements; access to equity markets; foreign currency exchange rates and interest rates; and the risk factors set forth in this Annual Report on Form 10-K.

The decision whether or not to pay dividends and the amount of any such dividends are subject to the discretion of the 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.

Changes to existing regulations related to income tax laws, royalty regimes, environmental laws or other regulations could adversely affect the Company s business, financial position, cash flows or results of operations.

Income tax laws, including recent U.S. tax reform and potential U.S. Treasury Department regulations and guidance, royalty regimes, environmental laws or other laws and regulations, and free trade agreements, including NAFTA, may change or be 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 does not operate all of its properties and assets and has limited control over factors that could adversely affect the Company s financial performance.

Other companies operate a portion of the assets in which Encana has ownership interests. Encana may have limited ability to exercise influence over operation 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 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.

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. Although Encana s financial results are consolidated in Canadian dollars, the Company reports its financial results in U.S. dollars. As Encana operates in both Canada and the U.S., many of the Company s expenses are incurred outside of the U.S. and 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 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 inability of our customers and other contractual counterparties to satisfy their obligations to us may have a material adverse effect on us.

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.

Table of Contents

The Company is subject to claims, litigation, administrative proceedings and regulatory actions that may not be resolved in the Company s favour.

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, monetary damages or the inability to engage in certain operations or transactions. 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 Item 3 of this Annual Report on Form 10-K.

Encana relies on certain key personnel, and if the Company is unable to attract and retain key personnel necessary for its business, Encana s operations may be negatively impacted.

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 unexpected 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 means there can be no assurance that the Company will be able to attract and retain such personnel with the required specialized skills necessary for its business.

Encana has certain indemnification obligations to certain counterparties that could have a material adverse effect on Encana.

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 a corporate reorganization to split into two independent publicly traded energy companies, Encana and Cenovus Energy Inc. (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.

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 claims against Encana pursuant to the provisions of the transaction agreements could have a material adverse effect on Encana.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

Encana is involved in various legal claims and actions arising in the normal course of the Company s operations. Although the outcome of these claims cannot be predicted with certainty, 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 impact on the Company s consolidated net earnings or loss for the period in which the effect becomes reasonably estimable. See Item 1A. Risk Factors, The Company is subject to claims, litigation, administrative proceedings and regulatory actions that may not be resolved in the Company s favour. of this Annual Report on Form 10-K.

For additional information, see Note 24 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

PART II

Item 5. Market for Registrant s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

On February 15, 2018, the Company announced plans to spend up to US$400 million to purchase for cancellation up to 35,000,000 common shares through a NCIB, subject to and following TSX approval. On February 26, 2018, the Company announced that the TSX accepted its notice of intention to commence the NCIB beginning February 28, 2018 and ending February 27, 2019, whereby purchases will be made on the open market through the facilities of the TSX, NYSE and/or alternative trading systems at the market price at the time of acquisition, as well as by other means as may be permitted by stock exchange rules and securities laws, including by private agreements. The Company plans to fund the NCIB with cash on hand and has not purchased any of its common shares pursuant to a NCIB within the 12 months prior to such announcements.

MARKET INFORMATION, SHAREHOLDERS, AND DIVIDEND INFORMATION

Market Information

Encana s common shares are listed and posted for trading on the TSX and NYSE under the symbol ECA . The following table sets forth the price range of Encana s common shares as reported by the TSX and NYSE for the periods indicated:

	Toronto Stock Exchange		New York Stock Exchange	
	High	Low	High	Low
	(C$ per share)		($ per share)	
2017				
Three months ended:				
December 31, 2017	16.93	13.03	13.52	10.16
September 30, 2017	14.97	10.54	12.01	8.17
June 30, 2017	16.40	10.64	12.25	8.02
March 31, 2017	18.13	13.61	13.84	10.07
2016				
Three months ended:				
December 31, 2016	17.70	12.03	13.40	8.96
September 30, 2016	13.87	9.56	10.75	7.35
June 30, 2016	11.47	7.41	9.03	5.63
March 31, 2016	8.26	4.14	6.37	3.01

Holders

The Company is authorized to issue an unlimited number of common shares and Class A Preferred Shares limited to a number equal to not more than 20 percent of the issued and outstanding number of common shares at the time of the issuance. As at February 16, 2018, there were approximately 973 million common shares outstanding held by 24,696 shareholders of record, and no Class A Preferred Shares outstanding.

Dividend Information

In 2017, Encana paid a quarterly dividend of US$0.015 per share (US$0.06 per share annually). In 2016, Encana paid a quarterly dividend of US$0.015 per share (US$0.06 per share annually). Dividend payments are not guaranteed and the amount of cash to be distributed as dividends in the future may change. Any decision to pay dividends will be determined at the discretion of the Board of Directors after consideration of numerous factors including: (i) the earnings of the Company; (ii) financial requirements for the Company s operations; (iii) the satisfaction by the Company of liquidity and solvency tests described in the CBCA; and (iv) any agreements relating to the Company s indebtedness that restrict the declaration and payment of dividends. See Item 1A. Risk Factors of this Annual Report on Form 10-K, The decision to pay dividends and the amount of such dividends is subject to the discretion of the Board of Directors based on numerous factors and may vary from time to time . The Company currently pays dividends quarterly to shareholders of record as of the 15th day (or the previous business day) of the last month of each calendar quarter, with the last business day of the same month being the corresponding payment date. The dividends paid on the common shares are expected to be designated as eligible dividends for Canadian income tax purposes, unless otherwise notified.

Table of Contents

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Information concerning securities authorized for issuance under equity compensation plans is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

None.

RECENT SALES OF UNREGISTERED EQUITY SECURITIES

None.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the Securities Act) or the Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to shareholders of Encana s common shares relative to the cumulative total returns of the S&P/TSX Composite Index and a peer group of 24 companies operating in the same industry as the Company on December 31 for each of the years indicated. The companies included in the peer group are Anadarko Petroleum Corporation; Apache Corporation; Baytex Energy Corporation; Cabot Oil & Gas Corporation; Canadian Natural Resources Limited; Chesapeake Energy Corporation; Concho Resources Inc.; Continental Resources Inc.; Crescent Point Energy Corporation; Enerplus Corporation; Devon Energy Corporation; EOG Resources Inc.; Hess Corporation; Murphy Oil Corporation; Newfield Exploration Corporation; Noble Energy Inc.; Marathon Oil Corporation; Obsidian Energy Ltd.; Pengrowth Energy Corporation; Pioneer Natural Resources Company; Range Resources Corporation; Southwestern Energy Company; Vermillion Energy Inc.; and Whiting Petroleum Corporation. The graph was prepared assuming $100 was invested on December 31, 2012 in Encana s common shares, the S&P 500, the S&P/TSX Composite Index and the peer groups, and dividends have been reinvested subsequent to the initial investment. The graph is included for historical comparative purposes only and should not be considered indicative of future share performance.

Table of Contents

Comparison of 5-Year Cumulative Total Return Among

Encana Corporation, the S&P 500, the S&P/TSX Composite Index and a Peer Group

Fiscal Year Ended December 31	2012	2013	2014	2015	2016	**2017**
Encana	$ 100.00	$ 95.00	$ 74.00	$ 28.00	$ 65.00	**$ 75.00**
Peer Group	100.00	129.00	99.00	59.00	87.00	**79.00**
S&P 500	100.00	132.00	150.00	153.00	171.00	**208.00**
S&P/TSX Composite Index	100.00	113.00	125.00	115.00	139.00	**151.00**

Table of Contents

Item 6: Selected Financial Data

The following table sets forth selected financial data of the Company and its consolidated subsidiaries over the five-year period ended December 31, 2017, which has been derived from the Company s audited Consolidated Financial Statements. The financial information below should be read in conjunction with Item 7 and Item 8 of this Annual Report on Form 10-K.

Year Ended December 31 (US$ millions, unless otherwise specified)	**2017**	2016	2015	2014	2013
Statement of Earnings Data					
Revenues	**4,443**	2,918	4,422	8,019	5,858
Impairments	**-**	1,396	6,473	-	21
Operating Income (Loss)	**1,068**	(1,881)	(6,301)	2,331	870
Gain (Loss) on Divestitures, Net	**404**	390	14	3,426	7
Net Earnings (Loss) Attributable to Common Shareholders	**827**	(944)	(5,165)	3,392	236
Per Share Data					
Net Earnings (Loss) per Common Share Basic & Diluted	**0.85**	(1.07)	(6.28)	4.58	0.32
Dividends Declared per Common Share	**0.06**	0.06	0.28	0.28	0.67
Weighted Average Common Shares Outstanding Basic & Diluted (millions)	**973.1**	882.6	822.1	741.0	737.7
Balance Sheet Data					
Cash and Cash Equivalents	**719**	834	271	338	2,566
Total Assets	**15,267**	14,653	15,614	24,492	17,599
Capital Lease Obligations and The Bow Office Building	**1,639**	1,570	1,591	1,959	2,175
Long-Term Debt, Including Current Portion	**4,197**	4,198	5,333	7,301	7,078
Total Shareholders Equity	**6,728**	6,126	6,167	9,685	5,147
Statement of Cash Flow Data					
Cash From (Used In) Operating Activities	**1,050**	625	1,681	2,667	2,289
Non-GAAP Cash Flow [(1)]	**1,343**	838	1,430	2,934	2,581
Capital Expenditures	**1,796**	1,132	2,232	2,526	2,712
Net Acquisitions & (Divestitures)	**(682)**	(1,052)	(1,838)	(1,329)	(521)

Foreign Exchange Rates (US$ per C$1)					
Average	**0.771**	0.755	0.782	0.905	0.971
Period End	**0.797**	0.745	0.723	0.862	0.940
Production Volumes					
Oil (Mbbls/d)	**76.3**	73.7	87.0	49.4	25.8
Total NGLs (Mbbls/d) [2]	**52.8**	48.4	46.4	37.4	28.1
Total Oil & NGLs (Mbbls/d)	**129.1**	122.1	133.4	86.8	53.9
Natural Gas (MMcf/d)	**1,104**	1,383	1,635	2,350	2,777
Total Production (MBOE/d)	**313.2**	352.7	405.9	478.5	516.7
Commodity Prices, Including Realized Gain (Loss) on Risk Management					
Oil ($/bbl)	**49.76**	48.68	49.68	86.03	88.19
Total NGLs ($/bbl) [2]	**34.72**	23.90	21.66	48.09	48.95
Oil & NGLs ($/bbl)	**43.61**	38.85	39.93	69.70	67.75
Natural Gas ($/Mcf)	**2.42**	2.10	3.89	4.59	4.09
Total ($/BOE)	**26.51**	21.69	28.81	35.21	29.05

[1] Non-GAAP Cash Flow is a non-GAAP measure and has no standardized meaning under U.S. GAAP. It is used by Management and investors to help assist in measuring Encana s ability to finance capital programs and meet financial obligations. It is not intended to replace Cash From (Used In) Operating Activities as a measure. Non-GAAP Cash Flow is defined and reconciled in the Non-GAAP Measures section under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

[2] Includes plant condensate.

Table of Contents

Supplemental Quarterly Financial Information (Unaudited)

See Note 26 of Encana s audited Consolidated Financial Statements under Item 8 of this Annual Report on Form 10-K.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

The MD&A is intended to provide a narrative description of Encana s business from management s perspective. This MD&A should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes for the period ended December 31, 2017 (Consolidated Financial Statements), which are included in Item 8 of this Annual Report on Form 10-K. Common industry terms and abbreviations are used throughout this MD&A and are defined in the Definitions, Conversions and Conventions sections of this Annual Report on Form 10-K. This MD&A includes the following sections:

- Executive Overview
- Results of Operations
- Liquidity and Capital Resources
- Accounting Policies and Estimates
- Non-GAAP Measures

Strategy

By executing on its strategy as outlined in Items 1 and 2 of this Annual Report on Form 10-K, Encana focuses on quality growth from high margin, scalable projects located in some of the best plays in North America, referred to as the Core Assets , comprising Montney and Duvernay in Canada and Eagle Ford and Permian in the U.S. These world-class assets form a multi-basin portfolio of oil, NGL and natural gas producing plays enabling flexible and efficient investment of capital. The Company rapidly deploys successful ideas and practices across these assets, becoming more efficient as innovative and sustainable technical improvements are implemented.

In executing its strategy, Encana focuses on its core values of One, Agile and Driven, which guide the organization to be flexible, responsive, determined and motivated with a commitment to excellence and a passion to succeed as a unified team.

In evaluating its operations, the Company reviews performance-based measures such as Non-GAAP Cash Flow and Non-GAAP Cash Flow Margin, which are non-GAAP measures and do not have any standardized meaning under U.S. GAAP. These measures may not be similar to measures presented by other issuers and should not be viewed as a substitute for measures reported under U.S. GAAP. Further information regarding these measures, including reconciliations to the closest GAAP measure, can be found in the Non-GAAP Measures section of this MD&A.

Table of Contents

Highlights

During 2017, Encana met or exceeded substantially all of the targets set in its full year 2017 guidance by successfully executing the Company s 2017 capital plan, maintaining operational efficiencies achieved in 2016 and seeking new ways to reduce costs. Higher benchmark prices during 2017 compared to 2016 contributed to increases in Encana s average realized oil, NGLs and natural gas prices of 27 percent, 46 percent and 23 percent, respectively, resulting in higher revenues.

Significant Developments

- Closed the sale of the Company s Piceance natural gas assets in northwestern Colorado to Caerus Oil and Gas LLC for proceeds of approximately $605 million, after closing and other adjustments. In conjunction with the sale, Encana also reduced its midstream commitments by approximately $430 million (undiscounted).

- Commenced processing of production volumes in support of the Company s liquids growth plans in Montney at the Tower, Saturn and Sunrise processing plants under a midstream agreement with Veresen Midstream Limited Partnership.

Financial Results

- Reported net earnings of $827 million, including before-tax amounts for net gains on risk management in revenues of $482 million, gain on divestitures of $404 million and foreign exchange gain of $279 million, as well as deferred tax expense of $666 million.

- Generated cash from operating activities of $1,050 million, Non-GAAP Cash Flow of $1,343 million and Non-GAAP Cash Flow Margin of $11.75 per BOE.

- Recovered current taxes of approximately $63 million and interest of $17 million, as well as received interest income of $33 million primarily resulting from the successful resolution of certain tax items previously assessed.

- Paid dividends of $0.06 per common share.

- Held cash and cash equivalents of $719 million and had available credit facilities of $4.5 billion for total liquidity of $5.2 billion at year end.

Capital Investment

- Reported total capital spending of $1,796 million which was within the full year 2017 guidance range of $1.6 billion to $1.8 billion.

- Directed $1,729 million, or 96 percent, of total capital spending to the Core Assets, of which 58 percent was directed to Permian.

- Focused on highly efficient capital activity and short-cycle high margin projects providing flexibility to respond to fluctuations in commodity prices.

Production

- Produced average oil and NGL volumes of 129.1 Mbbls/d which accounted for 41 percent of total production volumes and were within the full year 2017 guidance range of 127.0 Mbbls/d to 132.0 Mbbls/d. Average oil and plant condensate production volumes of 102.6 Mbbls/d were 79 percent of total liquids production volumes.

- Produced average natural gas volumes of 1,104 MMcf/d which accounted for 59 percent of total production volumes and were within the full year 2017 guidance range of 1,075 MMcf/d to 1,125 MMcf/d.

- Reported Core Assets production of 260.7 MBOE/d, or 83 percent of total production volumes, and delivered production growth of approximately 31 percent from the fourth quarter of 2016 to the fourth quarter of 2017 surpassing the top end of the full year 2017 guidance range of 25 to 30 percent.

Table of Contents

Operating Expenses

- Continued to benefit from operational efficiencies achieved in 2016, which contributed to further cost savings improvements in 2017.

- Achieved all targets set in the full year 2017 guidance range for transportation and processing expense, and upstream operating expense and administrative expense excluding long-term incentive costs.

- Reduced transportation and processing expense in 2017 by $56 million, or six percent, and reduced operating expense, excluding long-term incentive costs, by $78 million, or 14 percent, compared to 2016.

- Reduced administrative expense by $11 million, or six percent, excluding the impact of long-term incentive costs and restructuring charges compared to 2016.

2018 Outlook

Industry Outlook

The oil and gas industry is cyclical and commodity prices are inherently volatile. Oil prices during 2018 are expected to reflect global supply and demand dynamics as well as the geopolitical environment. At a meeting in November 2017, OPEC and certain non-OPEC countries agreed to further extend an agreement to voluntarily cut crude oil production through the end of 2018. The agreement, which was implemented in January 2017, and recent drawdowns of oil storage inventory levels, were generally supportive of oil prices in 2017; however, production growth in other countries continues to partially offset the expected benefit of the OPEC agreement. OPEC is scheduled to meet again in June 2018 to review production levels and a decision to discontinue or reduce the production cuts could negatively impact oil prices in 2018.

Natural gas prices in 2018 will be affected by the timing of supply and demand growth. Potential for improvement in U.S. natural gas prices is limited due to substantial production increases in Northeast U.S. and associated gas production in the Permian Basin, offsetting the positive impact of colder winter temperatures. Natural gas prices in Canada have seen significant negative price pressure as supply reached multi-year highs, surpassing regional demand and stressing effective pipeline capacity. Stronger condensate prices may also lend support to activity levels resulting in additional downward pressure on natural gas prices.

Company Outlook

Encana has positioned itself to be flexible and to continue to achieve strong returns from the Core Assets through this evolving price cycle. A portion of the Company s oil, NGL and natural gas production is sold at prevailing market prices, which fluctuate as a result of factors that are outside of Encana s control. The Company enters into derivative financial instruments which mitigate price volatility and help sustain revenues during periods of lower prices. As at February 12, 2018, the Company has hedged approximately 104,000 bbls/d of expected oil and condensate production

and 790 MMcf/d of expected natural gas production for the remainder of 2018 using a variety of structures at average prices of $54.48 per bbl and $3.03 per Mcf, respectively.

Markets for crude oil and natural gas are exposed to different price risks. While the market price for crude oil tends to move in the same direction as the global market, natural gas may vary between geographic regions depending on local supply and demand conditions. Encana has proactively utilized transportation contracts to diversify the Company s downstream markets and reduce significant exposure to any given market. Through a combination of derivative financial instruments and transportation capacity, Encana has removed the majority of its exposure to AECO pricing in 2018.

Capital Investment

Total anticipated 2018 capital investment of approximately $1.8 billion to $1.9 billion is expected to be primarily funded from 2018 cash generated from operating activities. Encana plans to focus the majority of its capital investment on its Core Assets with approximately 70 percent directed to Permian and Montney. Capital investment in Permian is expected to be focused on optimizing the cube development approach to maximize returns and recovery. Capital investment in Montney is expected to be allocated to both Cutbank Ridge and Pipestone with a focus on growing condensate. Access to liquids handling infrastructure planned for completion in the second half of 2018 is expected to support liquids growth in Montney.

Table of Contents

Encana continually strives to improve well performance by lowering drilling and completion costs through innovative techniques. Encana s large-scale cube development model utilizes multi-well pads and advanced completion designs to access stacked pay resource to maximize returns and resource recovery from its reservoirs. The impact of Encana s disciplined capital program and continuous innovation create flexibility and opportunity to grow cash flows and production volumes going forward.

Production

As part of the Company s long-term growth strategy, Encana has significantly shifted its production mix to a more balanced portfolio in the recent years, thereby reducing exposure to market volatility. In 2018, Encana expects to continue to focus on growing condensate and expects liquids production volumes of 165.0 Mbbls/d to 175.0 Mbbls/d and natural gas production volumes of 1,150 MMcf/d to 1,250 MMcf/d. Liquids production is expected to be approximately 46 percent of total production in 2018. Liquids growth from Montney will be supported by the Tower, Saturn and Sunrise processing plants completed in 2017, as well as two facilities expected to be completed in the second half of 2018. Core Asset production will account for the majority of total production volumes with significant oil and condensate growth in the second half of the year. Growing production in the Core Assets is expected to increase cash flows and deliver competitive returns.

Operating Expenses

Efficiency improvements and lower service costs are expected to be maintained through the support of the Company s culture of innovation and its focus on continuous improvement in operational execution. As activity in the industry begins to accelerate, Encana expects to continue pursuing innovative ways to reduce upstream operating and administrative expenses. Encana expects upstream operating expense of $3.00 per BOE to $3.30 per BOE and transportation and processing expense of $7.40 per BOE to $7.75 per BOE. Transportation and processing expense includes costs relating to the diversification of the Company s downstream markets that are expected to increase overall margins through higher prices. Administrative expense is expected to be between $1.25 per BOE to $1.50 per BOE. Guidance for upstream operating expense and administrative expense excludes long-term incentive costs.

Service costs are expected to increase with higher activity in the oil and gas industry and the recovery of commodity prices. Encana continues to offset any inflationary pressures with efficiency improvements and effective supply chain management, including favorable price negotiations.

Further information on Encana s 2018 Corporate Guidance can be accessed on the Company s website at www.encana.com.

Table of Contents

Selected Financial Information

($ millions)	2017	2016	2015
Product Revenues	**$ 2,999**	$ 2,443	$ 3,350
Gains (Losses) on Risk Management, net	**482**	(275)	592
Market Optimization	**863**	647	368
Other	**99**	103	112
Total Revenues	**4,443**	2,918	4,422
Total Operating Expenses [1]	**3,375**	4,799	10,723
Operating Income (Loss)	**1,068**	(1,881)	(6,301)
Total Other (Income) Expenses	**(362)**	(261)	1,709
Net Earnings (Loss) Before Income Tax	**1,430**	(1,620)	(8,010)
Net Earnings (Loss)	**$ 827**	$ (944)	$ (5,165)

(1) Total Operating Expenses include non-cash items such as DD&A, impairments, accretion of asset retirement obligations and long-term incentive costs.

Revenues

Encana s revenues are substantially derived from sales of oil, NGL and natural gas production. Increases or decreases in Encana s revenue, profitability and future production are highly dependent on the commodity prices the Company receives. Prices are market driven and fluctuate due to factors beyond the Company s control, such as supply and demand, seasonality and geopolitical and economic factors. Canadian Operations realized prices are closely linked to the Edmonton Condensate and AECO benchmark prices, except for production from Deep Panuke which is closely related to the Algonquin City Gate benchmark price due to the proximity of the offshore production platform to New England. The USA Operations realized prices generally reflect WTI and NYMEX benchmark prices. Realized NGL prices are significantly influenced by oil benchmark prices and the NGL production mix. Recent trends in benchmark prices relevant to Encana are shown in the table below.

Benchmark Prices

(average for the period)	2017	2016	2015
Oil & NGLs			
WTI ($/bbl)	**$ 50.95**	$ 43.32	$ 48.80
Edmonton Condensate (C$/bbl)	**66.90**	56.18	60.33

Natural Gas			
NYMEX ($/MMBtu)	**$ 3.11**	$ 2.46	$ 2.66
AECO (C$/Mcf)	**2.43**	2.09	2.77
Algonquin City Gate ($/MMBtu)	**3.68**	3.10	4.74

Table of Contents

Production Volumes and Realized Prices

	Production Volumes [1]			Realized Prices [2]		
	2017	2016	2015	**2017**	2016	2015
Oil (Mbbls/d, $/bbl)						
Canadian Operations	**0.4**	2.0	5.6	**$ 42.33**	$ 36.32	$ 43.90
USA Operations	**75.9**	71.7	81.4	**49.14**	38.67	43.31
Total	**76.3**	73.7	87.0	**49.10**	38.61	43.35
NGLs Plant Condensate (Mbbls/d, $/bbl)						
Canadian Operations	**23.1**	17.6	13.9	**50.57**	40.97	43.26
USA Operations	**3.2**	2.7	2.9	**40.64**	32.48	37.39
Total	**26.3**	20.3	16.8	**49.35**	39.84	42.26
NGLs Other (Mbbls/d, $/bbl)						
Canadian Operations	**6.0**	7.6	8.9	**25.19**	12.13	7.13
USA Operations	**20.5**	20.5	20.7	**19.42**	12.53	11.20
Total	**26.5**	28.1	29.6	**20.72**	12.42	9.98
Total NGLs (Mbbls/d, $/bbl)						
Canadian Operations	**29.1**	25.2	22.8	**45.35**	32.32	29.21
USA Operations	**23.7**	23.2	23.6	**22.30**	14.86	14.37
Total	**52.8**	48.4	46.4	**34.98**	23.94	21.66
Total Oil & NGLs (Mbbls/d, $/bbl)						
Canadian Operations	**29.5**	27.2	28.4	**45.30**	32.61	32.10
USA Operations	**99.6**	94.9	105.0	**42.74**	32.84	36.80
Total	**129.1**	122.1	133.4	**43.33**	32.79	35.80
Natural Gas (MMcf/d, $/Mcf)						
Canadian Operations	**838**	966	971	**2.16**	1.77	2.75
USA Operations	**266**	417	664	**3.03**	2.29	2.60
Total	**1,104**	1,383	1,635	**2.37**	1.93	2.69
Total Production (MBOE/d, $/BOE)						
Canadian Operations	**169.1**	188.2	190.2	**18.61**	13.82	18.84
USA Operations	**144.1**	164.5	215.7	**35.16**	24.78	25.93
Total	**313.2**	352.7	405.9	**26.22**	18.93	22.61
Production Mix (%)						
Oil & Plant Condensate	**33**	27	26			
NGLs Other	**8**	8	7			
Total Oil & NGLs	**41**	35	33			

Natural Gas	**59**	65	67
Core Asset Production			
Oil (Mbbls/d)	**72.6**	64.1	66.5
NGLs Plant Condensate (Mbbls/d)	**25.8**	19.2	15.1
NGLs Other (Mbbls/d)	**24.7**	22.9	21.3
Total NGLs (Mbbls/d)	**50.5**	42.1	36.4
Total Oil & NGLs (Mbbls/d)	**123.1**	106.2	102.9
Natural Gas (MMcf/d)	**826**	887	838
Total Production (MBOE/d)	**260.7**	254.2	242.6
% of Total Encana Production	**83**	72	60

(1) Average daily.
(2) Average per-unit prices, excluding the impact of risk management activities.

Table of Contents

Product Revenues

($ millions)	Oil	NGLs [1]	Natural Gas	Total
2015 Product Revenues	**$ 1,378**	**$ 367**	**$ 1,605**	**$ 3,350**
Increase (decrease) due to:				
Sales prices	(128)	33	(369)	(464)
Production volumes	(209)	24	(258)	(443)
2016 Product Revenues	**$ 1,041**	**$ 424**	**$ 978**	**$ 2,443**
Increase (decrease) due to:				
Sales prices	290	203	201	694
Production volumes	36	47	(221)	(138)
2017 Product Revenues	**$ 1,367**	**$ 674**	**$ 958**	**$ 2,999**

(1) Includes plant condensate.

Oil Revenues

2017 versus 2016

Oil revenues increased $326 million compared to 2016 primarily due to:

- Higher average realized oil prices of $10.49 per bbl, or 27 percent, increased revenues by $290 million. The increase reflected a higher WTI benchmark price which was up 18 percent. The increase was also due to higher utilization of pipelines to transport oil to more favourable markets to receive a higher realized price, as well as improved regional pricing in the USA Operations; and

- Higher average oil production volumes of 2.6 Mbbls/d increased revenues by $36 million. Higher volumes were primarily due to a successful drilling program in Permian (11.6 Mbbls/d), partially offset by the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 and the Tuscaloosa Marine Shale assets in the second quarter of 2017 (5.3 Mbbls/d), natural declines in the USA Other Upstream Operations (1.5 Mbbls/d) and Eagle Ford (1.3 Mbbls/d) and production constraints resulting from Hurricane Harvey in Eagle Ford and Permian during the third quarter of 2017 (0.5 Mbbls/d).

2016 versus 2015

Oil revenues decreased $337 million compared to 2015 primarily due to:

- Lower average realized oil prices of $4.74 per bbl, or 11 percent, decreased revenues by $128 million. The decrease reflected lower WTI and Edmonton Condensate benchmark prices which were down 11 percent and

seven percent, respectively; and

- Lower average oil production volumes of 13.3 Mbbls/d decreased revenues by $209 million. Lower volumes were primarily due to natural declines in the USA Other Upstream Operations (8.3 Mbbls/d) and on Montney oil wells (1.8 Mbbls/d), a reduced capital program in Eagle Ford (4.6 Mbbls/d) and the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 (3.1 Mbbls/d), partially offset by a successful drilling program in Permian (5.8 Mbbls/d).

Table of Contents

NGL Revenues

2017 versus 2016

NGL revenues increased $250 million compared to 2016 primarily due to:

- Higher average realized NGL prices of $11.04 per bbl, or 46 percent, increased revenues by $203 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 18 percent and 19 percent, respectively. The increase was also due to a shift in the NGL production mix to higher value condensate compared to 2016; and

- Higher average NGL production volumes of 4.4 Mbbls/d increased revenues by $47 million. Higher volumes were primarily due to successful drilling programs in the Core Assets (12.3 Mbbls/d), partially offset by asset sales (7.0 Mbbls/d) which mainly include the Gordondale and DJ Basin assets in the third quarter of 2016, and natural declines in Other Upstream Operations (0.6 Mbbls/d).

2016 versus 2015

NGL revenues increased $57 million compared to 2015 primarily due to:

- Higher average realized NGL prices of $2.28 per bbl, or 11 percent, increased revenues by $33 million, mainly reflecting a shift in the NGL production mix to higher value condensate compared to 2015; and

- Higher average NGL production volumes of 2.0 Mbbls/d increased revenues by $24 million. Higher volumes were primarily due to successful drilling programs in the Core Assets (7.8 Mbbls/d), partially offset by the sales of the Gordondale and DJ Basin assets in the third quarter of 2016 (4.5 Mbbls/d) and natural declines in the USA Other Upstream Operations (1.1 Mbbls/d).

Natural Gas Revenues

2017 versus 2016

Natural gas revenues decreased $20 million compared to 2016 primarily due to:

- Lower average natural gas production volumes of 279 MMcf/d decreased revenues by $221 million. Lower volumes were primarily due to asset sales (198 MMcf/d) which mainly include the Piceance natural gas assets in the third quarter of 2017 and the Gordondale and DJ Basin assets in the third quarter of 2016, natural declines in Other Upstream Operations (77 MMcf/d) and increased downtime resulting from scheduled third-party plant maintenance in Montney (19 MMcf/d), partially offset by a successful drilling program in Permian (17 MMcf/d);

partially offset by:

- Higher average realized natural gas prices of $0.44 per Mcf, or 23 percent, increased revenues by $201 million. The increase reflected higher NYMEX, AECO and Algonquin City Gate benchmark prices which were up 26 percent, 16 percent and 19 percent, respectively. The increase was also due to the diversification of the Company s downstream markets to capture a higher realized price.

Table of Contents

2016 versus 2015

Natural gas revenues decreased $627 million compared to 2015 primarily due to:

- Lower average realized natural gas prices of $0.76 per Mcf, or 28 percent, decreased revenues by $369 million. The decrease reflected lower NYMEX, AECO and Algonquin City Gate benchmark prices which were down eight percent, 25 percent and 35 percent, respectively; and

- Lower average natural gas production volumes of 252 MMcf/d decreased revenues by $258 million. Lower volumes were primarily due to the sale of the Haynesville natural gas assets in the fourth quarter of 2015 (152 MMcf/d), the sales of the Gordondale and DJ Basin assets in the third quarter of 2016 (53 MMcf/d) and natural declines in Other Upstream Operations (86 MMcf/d), partially offset by successful drilling programs in Montney and Duvernay (66 MMcf/d).

Gains (Losses) on Risk Management, Net

As a means of managing commodity price volatility, Encana enters into commodity derivative financial instruments on a portion of its expected oil, NGL and natural gas production volumes. The Company s commodity price mitigation program reduces volatility and helps sustain revenues during periods of lower prices. Further information on the Company s commodity price positions as at December 31, 2017 can be found in Note 22 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

The following table provides the effects of Encana s risk management activities on revenues.

	$ millions			Per-Unit		
	2017	2016	2015	**2017**	2016	2015
Realized Gains (Losses) on Risk Management						
Commodity Price						
Oil ($/bbl)	**$ 18**	$ 271	$ 201	**$ 0.66**	$ 10.07	$ 6.33
NGLs ($/bbl) [1]	**(5)**	-	-	**(0.26)**	(0.04)	-
Natural Gas ($/Mcf)	**20**	85	718	**0.05**	0.17	1.20
Other [2]	**7**	5	(2)	**-**	-	-
Total ($/BOE)	**40**	361	917	**$ 0.29**	$ 2.76	$ 6.20
Unrealized Gains (Losses) on Risk Management	**442**	(636)	(325)			
Total Gains (Losses) on Risk Management, Net	**$ 482**	$ (275)	$ 592			

(1) Includes plant condensate.
(2) Other primarily includes realized gains or losses from other derivative contracts with no associated production volumes.

Encana recognizes fair value changes from its risk management activities each reporting period. The changes in fair value result from new positions and settlements that occur during each period, as well as the relationship between contract prices and the associated forward curves. Realized gains or losses on risk management activities related to commodity price mitigation are included in the Canadian Operations, USA Operations and Market Optimization revenues as the contracts are cash settled. Unrealized gains or losses on fair value changes of unsettled contracts are included in the Corporate and Other segment.

Market Optimization Revenues

Market Optimization revenues relate to activities that provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification.

($ millions)	**2017**	2016	2015
Market Optimization	**$ 863**	$ 647	$ 368

Table of Contents

2017 versus 2016

Market Optimization revenues increased $216 million compared to 2016 primarily due to:

- Higher commodity prices ($166 million) and higher sales of third-party purchased volumes used for optimization activities ($50 million).

2016 versus 2015

Market Optimization revenues increased $279 million compared to 2015 primarily due to:

- Higher sales of third-party purchased volumes used for optimization activities ($290 million).

Other Revenues

Other revenues primarily includes amounts related to the sublease of office space in The Bow office building recorded in the Corporate and Other segment, as well as third party transportation and processing revenues with no associated volumes recorded in the Canadian and USA Operations segments. Further information on The Bow office sublease can be found in Note 13 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Operating Expenses

Production, Mineral and Other Taxes

Production, mineral and other taxes include production and property taxes. Production taxes are generally assessed as a percentage of oil and gas production revenues. Property taxes are generally assessed based on the value of the underlying assets.

	$ millions			$/BOE		
	2017	2016	2015	**2017**	2016	2015
Canadian Operations	**$ 20**	$ 23	$ 28	**$ 0.33**	$ 0.33	$ 0.41
USA Operations	**92**	76	116	**$ 1.74**	$ 1.27	$ 1.47
Total	**$ 112**	$ 99	$ 144	**$ 0.98**	$ 0.77	$ 0.97

2017 versus 2016

Production, mineral and other taxes increased $13 million compared to 2016 primarily due to:

.

Higher commodity prices in the USA Operations and higher oil and NGL production volumes in Permian ($31 million);

partially offset by:

- The sales of the DJ Basin and Gordondale assets in the third quarter of 2016 and the Piceance natural gas assets in the third quarter of 2017 ($10 million) and the recovery of certain production taxes in the USA Operations ($8 million).

2016 versus 2015

Production, mineral and other taxes decreased $45 million compared to 2015 primarily due to:

- Lower production volumes and commodity prices primarily in the USA Operations ($23 million), and the sales of the Haynesville natural gas assets in the fourth quarter of 2015 and the DJ Basin and Gordondale assets in the third quarter of 2016 ($17 million).

Table of Contents

Transportation and Processing

Transportation and processing expense includes transportation costs incurred to move product from production points to sales points including gathering, compression, pipeline tariffs, trucking and storage costs. Encana also incurs costs related to processing provided by third parties or through ownership interests in processing facilities to bring raw production to sales-quality product.

	$ millions			$/BOE		
	2017	2016	2015	**2017**	2016	2015
Canadian Operations	**$ 578**	$ 576	$ 654	**$ 9.35**	$ 8.35	$ 9.42
USA Operations	**164**	260	580	**$ 3.12**	$ 4.33	$ 7.37
Upstream Transportation and Processing	**742**	836	1,234	**$ 6.49**	$ 6.48	$ 8.33
Market Optimization	**103**	87	12			
Corporate and Other	**-**	(22)	6			
Total	**$ 845**	$ 901	$ 1,252			

2017 versus 2016

Transportation and processing expense decreased $56 million compared to 2016 primarily due to:

- Asset sales ($107 million) which mainly include the DJ Basin and Gordondale assets in the third quarter of 2016 and the Piceance natural gas assets in the third quarter of 2017, the renegotiation and expiration of certain transportation contracts ($32 million), lower natural gas volumes and lower gas gathering and processing fees in Montney and Other Upstream Operations ($9 million) and lower activity in Duvernay ($4 million);

partially offset by:

- Increased downstream processing and transportation costs primarily in Montney and Duvernay due to Encana s focus on liquids rich wells in the plays and costs relating to the diversification of the Company s downstream markets ($40 million), higher volumes and prices in Permian ($25 million), unrealized risk management gains on power financial derivative contracts in 2016 ($22 million) and the higher U.S./Canadian dollar exchange rate ($11 million).

2016 versus 2015

Transportation and processing expense decreased $351 million compared to 2015 primarily due to:

- The renegotiation and expiration of certain transportation contracts ($138 million), the sale of the Haynesville natural gas assets in the fourth quarter of 2015 ($97 million), the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($46 million), lower activity in Other Upstream Operations ($38 million), unrealized risk management gains on power financial derivative contracts ($28 million) and the lower U.S./Canadian dollar

exchange rate ($25 million);

partially offset by:

- Higher activity primarily in Duvernay and Permian ($24 million).

Table of Contents

Operating

Operating expense includes costs paid by Encana, net of amounts capitalized, to operate oil and gas properties in which the Company has a working interest. These costs primarily include labour, service contract fees, chemicals and fuel.

	$ millions			$/BOE		
	2017	2016	2015	**2017**	2016	2015
Canadian Operations	**$ 122**	$ 152	$ 152	**$ 1.92**	$ 2.16	$ 2.17
USA Operations	**331**	394	519	**$ 6.18**	$ 6.44	$ 6.55
Upstream Operating Expense [1]	**453**	546	671	**$ 3.88**	$ 4.16	$ 4.50
Market Optimization	**35**	35	33			
Corporate and Other	**18**	17	19			
Total	**$ 506**	$ 598	$ 723			

(1) 2017 Upstream Operating Expense per BOE includes long-term incentive costs of $0.19/BOE (2016 - costs of $0.29/BOE; 2015 - a recovery of $0.04/BOE).

2017 versus 2016

Operating expense decreased $92 million compared to 2016 primarily due to:

- Asset sales ($66 million) which mainly include the DJ Basin and Gordondale assets in the third quarter of 2016, the Piceance natural gas assets in the third quarter of 2017 and the Tuscaloosa Marine Shale assets in the second quarter of 2017, lower salaries and benefits and long-term incentive costs due to higher headcount dedicated to the capital program and a smaller increase in Encana s share price during 2017 compared to 2016 ($47 million) and cost-saving initiatives ($24 million);

partially offset by:

- Higher activity in Permian and Montney ($39 million) and the higher U.S./Canadian dollar exchange rate ($4 million).

2016 versus 2015

Operating expense decreased $125 million compared to 2015 primarily due to:

- Cost-saving initiatives ($101 million), lower activity primarily in Other Upstream Operations ($42 million), the sale of the Haynesville natural gas assets in the fourth quarter of 2015 ($28 million) and the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($23 million);

partially offset by:

- Higher long-term incentive costs resulting from the increase in Encana s share price ($55 million).

Further information on Encana s long-term incentives can be found in Note 19 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Purchased Product

Purchased product expense includes purchases of oil, NGLs and natural gas from third parties that are used to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification.

($ millions)	**2017**	2016	2015
Market Optimization	**$ 788**	$ 586	$ 323

Table of Contents

2017 versus 2016

Purchased product expense increased $202 million compared to 2016 primarily due to:

- Higher commodity prices ($152 million) and higher third-party volumes purchased for optimization activities ($50 million).

2016 versus 2015

Purchased product expense increased $263 million compared to 2015 primarily due to:

- Higher third-party volumes purchased for optimization activities ($322 million), partially offset by lower commodity prices ($59 million).

Depreciation, Depletion & Amortization

Proved properties within each country cost centre are depleted using the unit-of-production method based on proved reserves as discussed in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Depletion rates are impacted by impairments, acquisitions, divestitures and foreign exchange rates as well as fluctuations in 12-month average trailing prices which affect proved reserves volumes. Additional information can be found in the Critical Accounting Estimates section of this MD&A under Upstream Assets and Reserve Estimates. Corporate assets are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets.

	$ millions			$/BOE		
	2017	2016	2015	**2017**	2016	2015
Canadian Operations	**$ 236**	$ 260	$ 305	**$ 3.82**	$ 3.77	$ 4.39
USA Operations	**530**	523	1,088	**$ 10.09**	$ 8.68	$ 13.66
Upstream DD&A	**766**	783	1,393	**$ 6.70**	$ 6.06	$ 9.31
Market Optimization	**1**	-	-			
Corporate and Other	**66**	76	95			
Total	**$ 833**	$ 859	$ 1,488			

2017 versus 2016

DD&A decreased $26 million compared to 2016 primarily due to:

-

Lower production volumes ($85 million) and lower straight-line depreciation on corporate assets ($12 million), partially offset by higher depletion rates primarily in the USA Operations ($63 million) and the higher U.S./Canadian dollar exchange rate ($5 million).

The depletion rate increased $0.64 per BOE compared to 2016 primarily due to:

- Lower reserve volumes from the sale of the Piceance natural gas assets in the third quarter of 2017, partially offset by ceiling test impairments recognized in the first six months of 2016 in the Canadian and USA Operations, and the sale of the DJ Basin assets in the third quarter of 2016. The sale of the Piceance natural gas assets resulted in the recognition of a gain on divestiture, whereas proceeds from the sale of the DJ Basin assets were deducted from the U.S. full cost pool. Additional information on the divestitures can be found in Note 3 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2016 versus 2015

DD&A decreased $629 million compared to 2015 primarily due to:

- Lower depletion rates in the Canadian and USA Operations ($334 million), lower production volumes in the USA Operations ($245 million) and the lower U.S./Canadian dollar exchange rate ($17 million).

Table of Contents

The depletion rate decreased $3.25 per BOE compared to 2015 primarily due to:

- Ceiling test impairments recognized in the first six months of 2016 in the Canadian and USA Operations and ceiling test impairments recognized in 2015 in the USA Operations, the sale of the DJ Basin assets in the third quarter of 2016, the sale of the Haynesville natural gas assets in the fourth quarter of 2015, the sale of certain assets in Wheatland in the first quarter of 2015 and the lower U.S./Canadian dollar exchange rate.

Impairments

Under full cost accounting, the carrying amount of Encana s oil and natural gas properties within each country cost centre is subject to a ceiling test at the end of each quarter. Ceiling test impairments are recognized when the capitalized costs, net of accumulated depletion and the related deferred income taxes, exceed the sum of the estimated after-tax future net cash flows from proved reserves as calculated under SEC requirements using the 12-month average trailing prices and discounted at 10 percent.

($ millions)	**2017**	2016	2015
Canadian Operations	**$ -**	$ 493	$ -
USA Operations	**-**	903	6,473
Total	**$ -**	$ 1,396	$ 6,473

The Company did not recognize any ceiling test impairments for 2017. The ceiling test impairments in 2016 and 2015 were primarily due to the decline in the 12-month average trailing prices, which reduced the Canadian and USA Operations proved reserves volumes and values as calculated under SEC requirements.

The 12-month average trailing prices used in the ceiling test calculations were based on the benchmark prices below. The benchmark prices were adjusted for basis differentials to determine local reference prices, transportation costs and tariffs, heat content and quality.

	Oil & NGLs		**Natural Gas**	
	WTI	Edmonton Condensate [2]	Henry Hub	AECO
	($/bbl)	(C$/bbl)	($/MMBtu)	(C$/MMBtu)
12-Month Average Trailing Reserves Pricing [1]				
2017	**51.34**	**67.65**	**2.98**	**2.32**
2016	42.75	55.39	2.49	2.17
2015	50.28	61.94	2.58	2.69

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

Edmonton Condensate benchmark price has replaced the previously disclosed Edmonton Light Sweet benchmark price.

The Company believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana s oil and natural gas properties or the future net cash flows expected to be generated from such properties. The discounted after-tax future net cash flows do not consider the fair market value of unamortized unproved properties, or probable or possible liquids and natural gas reserves. In addition, there is no consideration given to the effect of future changes in commodity prices. Encana manages its business using estimates of reserves and resources based on forecast prices and costs. Additional information on the ceiling test calculation can be found in the Critical Accounting Estimates section of this MD&A under Upstream Assets and Reserve Estimates.

Table of Contents

Administrative

Administrative expense represents costs associated with corporate functions provided by Encana staff in the Calgary and Denver offices. Costs primarily include salaries and benefits, general office, information technology and long-term incentive costs.

	2017	2016	2015
Administrative ($ millions)	**$ 254**	$ 309	$ 275
Administrative ($/BOE) [1]	**$ 2.22**	$ 2.40	$ 1.86

(1) 2017 administrative expense per BOE includes long-term incentive costs of $0.67/BOE. 2016 administrative expense per BOE includes long-term incentive costs and restructuring costs of $0.93/BOE (2015 - $0.36/BOE).

2017 versus 2016

Administrative expense in 2017 decreased $55 million from 2016 primarily due to lower restructuring costs ($34 million), lower third party payments relating to previously divested assets ($11 million) as well as lower long-term incentive costs resulting from a smaller increase in Encana s share price during 2017 compared to 2016 ($10 million).

2016 versus 2015

Administrative expense in 2016 increased $34 million from 2015 primarily due to long-term incentive costs resulting from the increase in Encana s share price ($99 million), partially offset by lower restructuring costs ($30 million), lower salaries and benefits as a result of a lower headcount ($13 million), lower office costs ($12 million) and the lower U.S./Canadian dollar exchange rate ($7 million).

During the first quarter of 2016, Encana completed workforce reductions announced in February 2016 to better align staffing levels and the organizational structure with its reduced capital spending program as a result of the low commodity price environment. Encana incurred restructuring costs of $34 million during 2016 compared to $64 million in 2015. Further information on restructuring costs can be found in Note 18 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Other (Income) Expenses

($ millions)	2017	2016	2015
Interest	**$ 363**	$ 397	$ 614
Foreign exchange (gain) loss, net	**(279)**	(210)	1,082
(Gain) loss on divestitures, net	**(404)**	(390)	(14)
Other (gains) losses, net	**(42)**	(58)	27
Total Other (Income) Expenses	**$ (362)**	$ (261)	$ 1,709

Interest

Interest expense primarily includes interest on Encana s long-term debt arising from U.S. dollar denominated unsecured notes and balances drawn on the Company s credit facilities. Encana also incurs interest on the Company s long-term obligations for The Bow office building and capital leases.

2017 versus 2016

Interest expense in 2017 decreased $34 million compared to 2016 primarily due to lower interest on debt ($29 million) resulting from the early retirement of long-term debt in March 2016. Further information on the March 2016 debt retirement can be found in the Liquidity and Capital Resources section of this MD&A.

Table of Contents

2016 versus 2015

Interest expense in 2016 decreased $217 million from 2015 primarily due to a one-time payment of $165 million in the second quarter of 2015 associated with the April 2015 early redemptions of the Company s $700 million 5.90 percent notes due December 1, 2017 and its C$750 million 5.80 percent medium-term notes due January 18, 2018 and lower interest on debt following these redemptions, as well as the early retirement of long-term debt in March 2016 as discussed in the Liquidity and Capital Resources section of this MD&A.

Foreign Exchange (Gain) Loss, Net

Foreign exchange gains and losses result from the impact of fluctuations in the Canadian to U.S. dollar exchange rate. Further details on changes in foreign exchange gains or losses can be found in Note 5 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Additional information on foreign exchange rates and the effects of foreign exchange rate changes can be found in Items 6 and 7A of this Annual Report on Form 10-K.

2017 versus 2016

In 2017, Encana recorded a higher net foreign exchange gain compared to 2016 ($69 million). The change was primarily due to higher unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada ($113 million) and unrealized foreign exchange gains on the translation of U.S. dollar risk management contracts issued from Canada compared to losses in 2016 ($48 million), partially offset by foreign exchange losses on the settlement of U.S. dollar financing debt issued from Canada compared to gains in 2016 ($87 million). In 2017, unrealized foreign exchange on the translation of U.S. dollar financing debt issued from Canada included an out-of-period adjustment of $68 million, before tax, in respect of unrealized losses on a foreign-denominated capital lease obligation since December 31, 2013. Further information on the out-of-period adjustment can be found in Note 5 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2016 versus 2015

In 2016, Encana recorded a net foreign exchange gain compared to a net loss in 2015 ($1,292 million). The change was primarily due to unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada compared to losses in 2015 ($884 million) and foreign exchange gains on the settlement of U.S. dollar financing debt issued from Canada compared to losses in 2015 ($342 million).

(Gain) Loss on Divestitures, Net

Amounts received from the Company s divestiture transactions are deducted from the respective Canadian and U.S. full cost pools, except for divestitures that result in a significant alteration between capitalized costs and proved reserves in a country cost centre, in which case a gain or loss is recognized. Additional information regarding gains on divestitures can be found in Note 3 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2017

Gain on divestitures in 2017 primarily includes the before tax gain on the sale of the Piceance natural gas assets of approximately $406 million.

2016

Gain on divestitures in 2016 primarily included the gain on the sale of the Gordondale assets of approximately $394 million.

2015

Gain on divestitures in 2015 primarily included a gain on the sale of the Encana Place office building located in Calgary of approximately $12 million.

Table of Contents

Other (Gains) Losses, Net

Other (gains) losses, net primarily includes other non-recurring revenues or expenses and may also include items such as interest income on short-term investments, interest received from tax authorities, reclamation charges relating to decommissioned assets and earnings/losses from equity investments.

2017

Other gains in 2017 primarily includes interest received of $33 million resulting from the successful resolution of certain tax items previously assessed by the taxing authorities relating to prior taxation years and interest income on short-term investments of $6 million, partially offset by reclamation charges relating to decommissioned assets of $4 million.

2016

Other gains in 2016 primarily included a gain of $89 million on the early retirement of long-term debt as discussed in the Liquidity and Capital Resources section of this MD&A, partially offset by a one-time third party payment relating to a previously divested asset of $20 million and reclamation charges relating to decommissioned assets of $7 million.

2015

Other losses in 2015 primarily included reclamation charges relating to decommissioned assets of $22 million.

Table of Contents

Income Tax

($ millions)	2017	2016	2015
Current Income Tax Expense (Recovery)	**$ (63)**	$ (78)	$ (34)
Deferred Income Tax Expense (Recovery)	**666**	(598)	(2,811)
Income Tax Expense (Recovery)	**$ 603**	$ (676)	$ (2,845)
Effective Tax Rate	**42.2%**	41.7%	35.5%

Income Tax Expense (Recovery)

2017 versus 2016

Total income tax in 2017 was an expense of $603 million compared to a recovery of $676 million in 2016 primarily due to:

- Net earnings before income tax in 2017 compared to a net loss before income tax in 2016.

Deferred income tax in 2017 was an expense of $666 million compared to a recovery of $598 million in 2016 due to:

- Net earnings (loss) before income tax as discussed above; and

- Deferred tax expense in 2017 includes a provisional adjustment of $327 million resulting from the re-measurement of the Company s tax position due to a reduction of the U.S. federal corporate tax rate from 35 percent to 21 percent under the Tax Cuts and Jobs Act (U.S. Tax Reform) as enacted on December 22, 2017. The adjustment of $327 million includes a $26 million valuation allowance re-measurement with respect to U.S. foreign tax credits and U.S. charitable donations. In addition, the deferred tax expense includes a valuation allowance of $28 million against U.S. state losses; and

- Deferred tax recovery in 2016 was primarily due to the recognition of non-cash ceiling test impairments.

The current income tax recovery in 2017 was primarily due to the successful resolution of certain tax items previously assessed by the taxing authorities relating to prior taxation years as well as the reclassification of $10 million U.S. alternative minimum tax to a long-term receivable from a deferred tax asset due to U.S. Tax Reform.

2016 versus 2015

Total income tax recovery decreased $2,169 million compared to 2015 primarily due to:

- Lower non-cash ceiling test impairments and foreign exchange gains;

partially offset by:

- An increase to the valuation allowance recorded against the deferred tax assets in respect of U.S. foreign tax credits and U.S. charitable donations totaling $121 million.

Current income tax recoveries in 2016 and 2015 were primarily due to amounts recorded in respect of prior periods.

Effective Tax Rate

Encana s annual effective income tax rate is impacted by earnings, income tax related to foreign operations, the effect of legislative changes including U.S. Tax Reform, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding. The Company s effective tax rate was 42.2 percent for 2017, which is higher than the Canadian statutory rate of 27 percent primarily due to U.S. Tax Reform, which increased Encana s effective tax rate by 22.9 percent. The effective tax rate for 2017 was also impacted by the tax reassessments discussed above as well as the valuation allowance taken against U.S. state losses. The 2016 and 2015 effective tax rates exceeded the Canadian statutory tax rate of 27 percent primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings.

Table of Contents

Tax interpretations, regulations and legislation, including U.S. Tax Reform and potential Treasury Department regulations and guidance, in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As a result, there are tax matters under review for which the timing of resolution is uncertain. The Company believes that the provision for income taxes is adequate.

Additional information on income taxes can be found in Note 6 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Sources of Liquidity

The Company has the flexibility to access cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities as well as debt and equity capital markets. Encana closely monitors the accessibility of cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. In addition, the Company may use cash and cash equivalents, cash from operating activities, or proceeds from asset divestitures and share issuances to fund its operations or to manage its capital structure as discussed below. At December 31, 2017, $314 million in cash and cash equivalents was held by U.S. subsidiaries. The cash held by U.S. subsidiaries is accessible and may be subject to additional Canadian income taxes and U.S. withholding taxes if repatriated.

The Company s capital structure consists of total shareholders equity plus long-term debt, including the current portion. The Company s objectives when managing its capital structure are to maintain financial flexibility to preserve Encana s access to capital markets and its ability to meet financial obligations and finance internally generated growth, as well as potential acquisitions. Encana has a practice of maintaining capital discipline and strategically managing its capital structure by adjusting capital spending, adjusting dividends paid to shareholders, issuing new shares, purchasing shares for cancellation through a NCIB, issuing new debt or repaying existing debt.

($ millions, except as indicated)	**2017**	2016	2015
Cash and Cash Equivalents	**$ 719**	$ 834	$ 271
Available Credit Facility Encana (1)	**3,000**	3,000	2,350
Available Credit Facility U.S. Subsidiary (1)	**1,500**	1,500	1,500
Total Liquidity	**5,219**	5,334	4,121
Long-Term Debt	**4,197**	4,198	5,333
Total Shareholders Equity	**6,728**	6,126	6,167
Debt to Capitalization (%) (2)	**38**	41	46
Debt to Adjusted Capitalization (%) (3)	**22**	23	28

(1) Collectively, the Credit Facilities .
(2) Calculated as long-term debt, including the current portion, divided by shareholders equity plus long-term debt, including the current portion.
(3) A non-GAAP measure which is defined in the Non-GAAP Measures section of this MD&A.

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under the Credit Facilities. Management monitors Debt to Adjusted Capitalization, which is a non-GAAP measure defined in the Non-GAAP Measures section of this MD&A, as a proxy for Encana s financial covenant under the Credit Facilities, which requires debt to adjusted capitalization to be less than 60 percent. The definitions used in the covenant under the Credit Facilities adjust capitalization for cumulative historical ceiling test impairments that were recorded as at December 31, 2011 in conjunction with the Company s January 1, 2012 adoption of U.S. GAAP. Additional information on financial covenants can be found in Note 12 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Table of Contents

Sources and Uses of Cash

During 2017, Encana primarily generated cash through operating activities and proceeds from divestitures. The following table summarizes the sources and uses of the Company s cash and cash equivalents.

($ millions)	Activity Type	2017	2016	2015
Sources of Cash and Cash Equivalents				
Cash from operating activities	Operating	**$ 1,050**	$ 625	$ 1,681
Proceeds from divestitures	Investing	**736**	1,262	1,908
Issuance of common shares, net of offering costs	Financing	**-**	1,129	1,088
Other	Investing	**77**	51	-
		1,863	3,067	4,677
Uses of Cash and Cash Equivalents				
Capital expenditures	Investing	**1,796**	1,132	2,232
Acquisitions	Investing	**54**	210	70
Net repayment of revolving long-term debt	Financing	**-**	650	627
Repayment of long-term debt	Financing	**-**	400	1,302
Dividends on common shares	Financing	**57**	51	152
Other	Investing/Financing	**82**	66	332
		1,989	2,509	4,715
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**11**	5	(29)
Increase (Decrease) in Cash and Cash Equivalents		**$ (115)**	$ 563	$ (67)

Operating Activities

Cash from operating activities in 2017 was $1,050 million and was primarily impacted by recovering commodity prices, the Company s efforts in maintaining cost efficiencies achieved in 2016, the effects of the commodity price mitigation program, changes in production volumes, a current tax recovery and interest relating to the successful resolution of certain tax items previously assessed by the taxing authorities, and changes in non-cash working capital. Additional detail on changes in non-cash working capital can be found in Note 23 to the Consolidated Financial

Statements included in Item 8 of this Annual Report on Form 10-K. Encana expects it will continue to meet the payment terms of its suppliers.

Non-GAAP Cash Flow in 2017 was $1,343 million and was primarily impacted by the items affecting cash from operating activities which are discussed below and in the Results of Operations section of this MD&A.

2017 versus 2016

Net cash from operating activities increased $425 million compared to 2016 primarily due to:

- Higher realized commodity prices ($694 million), higher liquids production volumes ($83 million), lower operating expense, excluding non-cash long-term incentive costs ($73 million), lower transportation and processing expense ($56 million), higher interest income recorded in other gains ($39 million), lower restructuring costs ($34 million) and lower interest on long-term debt ($29 million);

partially offset by:

- Lower realized gains on risk management included in revenues ($321 million), lower natural gas production volumes ($221 million) and changes in non-cash working capital ($66 million).

Table of Contents

2016 versus 2015

Net cash from operating activities decreased $1,056 million compared to 2015 primarily due to:

- Lower realized gains on risk management included in revenues ($556 million), lower realized commodity prices ($464 million), lower production volumes ($443 million) and changes in non-cash working capital ($449 million);

partially offset by:

- Lower transportation and processing expense ($351 million), lower operating expenses and administrative expense, excluding non-cash long-term incentive costs ($240 million), lower interest on long-term debt ($201 million), lower production, mineral and other taxes ($45 million) and a higher current tax recovery ($44 million).

Investing Activities

Capital expenditures and divestitures have been Encana s primary investing activities over the past three years. The capital spending program increased in 2017 compared to 2016 as commodity prices began to stabilize. Capital expenditures and divestiture activity are summarized in Note 3 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

2017

Net cash used in investing activities in 2017 was $1,037 million primarily due to capital expenditures, partially offset by proceeds from divestitures. Capital expenditures in 2017 increased $664 million compared to 2016 due to the increase in Encana s capital program for 2017. Capital expenditures in the Core Assets totaled $1,729 million, representing 96 percent of total capital expenditures, and increased $635 million compared to 2016, primarily in Permian ($372 million), Eagle Ford ($93 million) and Montney ($205 million). Capital expenditures exceeded cash from operating activities by $746 million and the difference was funded using cash on hand and proceeds from divestitures.

Acquisitions in 2017 were $54 million, which primarily included land purchases with oil and liquids rich potential.

Divestitures in 2017 were $736 million, which primarily included the sale of the Piceance natural gas assets in northwestern Colorado, comprising approximately 550,000 net acres of leasehold and 3,100 operated wells. Divestitures also included the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana and the sale of certain properties that did not complement Encana s existing portfolio of assets.

2016

Net cash used in investing activities in 2016 was $29 million primarily due to capital expenditures and acquisitions, partially offset by proceeds from divestitures. Capital expenditures in 2016 decreased $1,100 million compared to 2015 due to a reduced capital program and cost savings initiatives implemented in 2016. Capital expenditures in the Core Assets totaled $1,094 million, representing 97 percent of total capital expenditures, and decreased $756 million compared to 2015, primarily in Eagle Ford ($359 million), Permian ($287 million) and Duvernay ($92 million).

Capital expenditures exceeded cash from operating activities by $507 million and the difference was funded using proceeds from divestitures.

Acquisitions in 2016 were $210 million, which primarily included $135 million for the purchase of natural gas gathering and water handling assets in Piceance located in Colorado. Acquisitions in 2016 also included the purchase of land and property in Eagle Ford with oil and liquids rich potential.

Divestitures in 2016 were $1,262 million, which primarily included the following:

- Proceeds of approximately $633 million, after closing and other adjustments, for the sale of the DJ Basin assets located in northern Colorado, comprising approximately 51,000 net acres;

- Proceeds of approximately C$600 million ($455 million), after closing adjustments, for the sale of the Gordondale assets which included approximately 54,200 net acres of land and associated infrastructure in Montney located in northwestern Alberta; and

Table of Contents

- Proceeds of approximately $135 million from the sale of certain natural gas leasehold interests in Piceance located in Colorado.

2015

Net cash used in investing activities in 2015 was $665 million primarily due to capital expenditures, partially offset by proceeds from divestitures. Capital expenditures during 2015 were $2,232 million, of which $1,850 million or 83 percent, was directed to the Core Assets. Capital expenditures exceeded cash from operating activities by $551 million with the difference being funded using proceeds from divestitures.

Divestitures in 2015 were $1,908 million, which primarily included the following:

- Proceeds of approximately C$557 million ($467 million), after closing adjustments, for the sale of certain assets in Wheatland located in central and southern Alberta;

- Proceeds of approximately C$450 million ($355 million), after closing adjustments, for the sale of certain natural gas gathering and compression assets in Montney located in northeastern British Columbia; and

- Proceeds of approximately $769 million, after closing adjustments, for the sale of the Haynesville natural gas assets located in northern Louisiana.

Financing Activities

Net cash used in financing activities over the past three years has been impacted by Encana s strategy to enhance liquidity and strengthen its balance sheet through debt repayments and common share offerings. The Company has paid dividends each of the past three years, though the dividend paid per common share decreased in 2016.

2017 versus 2016

Net cash used in financing activities in 2017 increased $101 million from 2016. The change was primarily due to the issuance of common shares in 2016 ($1,129 million), partially offset by a net repayment of revolving long-term debt ($650 million) and a repayment of long-term debt ($400 million) in 2016.

2016 versus 2015

Net cash used in financing activities in 2016 decreased $1,016 million from 2015. The decrease was primarily due to a lower repayment of long-term debt ($902 million) and lower cash dividend payments ($101 million).

The transactions affecting the changes in financing activities are discussed in more detail below.

2017

Encana s long-term debt totaled $4,197 million at December 31, 2017 and there was no current portion outstanding. At December 31, 2017, Encana has no long-term debt maturities until 2019 and over 73 percent of the Company s debt is not due until 2030 and beyond.

The Company continues to have full access to the Credit Facilities, which remain committed through July 2020. The Credit Facilities provide financial flexibility and allow the Company to fund its operations, development activities or capital program. At December 31, 2017, Encana had no outstanding balance under the Credit Facilities.

In 2017, Encana filed a shelf registration statement in the U.S. and had access to a Canadian shelf prospectus filed in 2016, whereby the Company may issue from time to time, debt securities, common shares, Class A preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units in Canada and/or the U.S. In 2016 and 2015, the Company filed prospectus supplements for the issuance of common shares as described below. At December 31, 2017, $4.8 billion remained accessible under the Canadian shelf prospectus. The ability to issue securities under the Canadian shelf prospectus or U.S. shelf registration statement is dependent upon market conditions.

Table of Contents

2016

Encana s long-term debt totaled $4,198 million at December 31, 2016 and there was no current portion outstanding.

In March 2016, the Company completed tender offers (collectively, the Tender Offers) for certain of the Company s outstanding senior notes (collectively, the Notes) and accepted for purchase $489 million aggregate principal amount of Notes. The Company paid an aggregate amount of $406 million, including accrued and unpaid interest of $6 million and an early tender premium of $14 million, which resulted in the recognition of a net gain on the early debt retirement of $89 million, before tax. The Company used cash on hand and borrowings under the Credit Facilities to fund the Tender Offers. Further information on the Tender Offers can be found in Note 12 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

On September 23, 2016, Encana completed a public offering (the 2016 Share Offering) of 107,000,000 common shares of Encana at a price of $9.35 per common share for gross proceeds of approximately $1.0 billion ($981 million of net cash proceeds). On October 4, 2016, an over-allotment option granted to the underwriters (the Over-Allotment Option) to purchase up to an additional 16,050,000 common shares at a price of $9.35 per common share was exercised in full for additional gross proceeds of approximately $150 million, bringing the aggregate gross proceeds to approximately $1.15 billion ($1.13 billion of net cash proceeds). Further information on the 2016 Share Offering can be found in Note 15 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

During the third quarter of 2016, Encana used a portion of the net proceeds from the 2016 Share Offering and divestitures to repay indebtedness under the Credit Facilities. At December 31, 2016, Encana had no outstanding balance under the Credit Facilities and no longer had access to its U.S. Commercial Paper (U.S. CP) program as a result of a split credit rating.

2015

Encana s long-term debt totaled $5,333 million at December 31, 2015 and there was no current portion outstanding.

During 2015, Encana implemented a U.S. CP program which was fully supported by the Credit Facilities and used proceeds from the U.S. CP program and cash on hand to repay outstanding LIBOR loan balances of approximately $1,277 million. At December 31, 2015, Encana had outstanding balances under the Credit Facilities which reflected $440 million of U.S. CP issuances and $210 million of principal obligations related to LIBOR loans.

In March 2015, the Company filed a prospectus supplement to the Company s shelf prospectus (the 2015 Share Offering) and issued 98,458,975 common shares of Encana, including common shares issued under an over-allotment option, for aggregate gross proceeds of approximately C$1.44 billion ($1.13 billion). After deducting underwriters fees and costs of the 2015 Share Offering, the net proceeds received were approximately C$1.39 billion ($1.09 billion).

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Common shares issued in the 2016 Share Offering and 2015 Share Offering were not eligible to receive the dividends paid on September 30, 2016 and March 31, 2015, respectively.

($ millions, except as indicated)	**2017**	2016	2015
Dividend Payments [1]	**$ 58**	$ 52	$ 225
Dividend Payments ($/share)	**0.06**	0.06	0.28

(1) Dividend payments in 2017 included $1 million (2016 - $1 million; 2015 - $73 million) in common shares issued in lieu of cash dividends under Encana s DRIP.

Dividend payments remained stable in 2017 after the Company reset its annualized dividend to $0.06 per common share during 2016 to better align the dividend with Encana s cash flows and provide flexibility to use available cash for investment in the Company s portfolio.

Table of Contents

The dividends paid in 2015 included $73 million in common shares issued in lieu of cash dividends under Encana s Dividend Reinvestment Plan (DRIP). The common shares issued under the DRIP decreased in 2016 primarily as a result of the lower dividend paid per common share in 2016 as well as Encana s December 14, 2015 announcement that any dividends subsequent to December 31, 2015 distributed to shareholders participating in the DRIP would no longer be issued from its treasury with a discount to the average market price of the common shares.

On February 14, 2018, the Board of Directors declared a dividend of $0.015 per common share payable on March 29, 2018 to common shareholders of record as of March 15, 2018.

Off-Balance Sheet Arrangements

The Company may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. Encana s material off-balance sheet arrangements include transportation and processing agreements, drilling rig commitments, and operating leases, as outlined in the Contractual Obligations table below, as well as undrawn letters of credit, all of which are customary agreements in the oil and gas industry. Other than the items discussed above, there are no other transactions, arrangements, or relationships with unconsolidated entities or persons that are reasonably likely to materially affect the Company s liquidity or the availability of, or requirements for, capital resources.

Contractual Obligations

Contractual obligations arising from long-term debt, capital leases, risk management liabilities, asset retirement obligations and The Bow office building are recognized on the Company s Consolidated Balance Sheet. The following table outlines the Company s obligations and commitments at December 31, 2017:

	Expected Future Payments				
($ millions)	2018	2019 - 2020	2021 - 2022	Thereafter	Total
Long-Term Debt	$ -	$ 500	$ 600	$ 3,111	**$ 4,211**
Interest Payments on Long-Term Debt	267	485	446	2,546	**3,744**
Capital Leases	79	173	89	33	**374**
Interest Payments on Capital Leases	20	25	6	5	**56**
Risk Management Liabilities	236	13	-	-	**249**
Asset Retirement Obligation [1]	45	279	74	957	**1,355**
The Bow Office Building	11	26	31	493	**561**
Interest Payments on The Bow Office Building	65	128	125	802	**1,120**
Obligations	723	1,629	1,371	7,947	**11,670**

Transportation and Processing	604	1,371	1,100	2,315	**5,390**
Drilling and Field Services	198	60	8	-	**266**
Operating Leases	18	32	30	46	**126**
Commitments [1]	820	1,463	1,138	2,361	**5,782**
Total Contractual Obligations	$ 1,543	$ 3,092	$ 2,509	$ 10,308	**$ 17,452**
The Bow Office Building Sublease Recoveries [1]	$ (37)	$ (76)	$ (77)	$ (636)	**$ (826)**

(1) Undiscounted.

Interest Payments on Long-Term Debt, Capital Leases and The Bow Office Building represent scheduled cash payments on the respective obligations. Further information can be found in Notes 12 and 13 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Capital Leases relates to an office building and the obligation related to the Deep Panuke Production Field Centre. Further information can be found in Note 13 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Table of Contents

Risk Management Liabilities represents Encana s net liability position with counterparties. Further information can be found in Note 22 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Asset Retirement Obligation represents estimated costs arising from the obligation to fund the disposal of long-lived assets upon their abandonment. The majority of Encana s asset retirement obligations relate to the plugging of wells and related abandonment of oil and gas properties including an offshore production platform, processing plants and land or seabed restoration. Revisions to estimated retirement obligations can result from changes in regulatory requirements, changes in retirement cost estimates, revisions to estimated inflation rates and estimated timing of abandonment. Further information can be found in Note 14 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

The Bow Office Building relates to the 25-year lease agreement with a third party developer that commenced in 2012. Encana has recognized the accumulated construction costs for The Bow office building as an asset with a related liability. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has subleased approximately 50 percent of The Bow office space under the lease agreement. The Bow Office Building Sublease Recoveries in the table above include the amounts expected to be recovered from the sublease. Further information can be found in Note 13 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Transportation and Processing commitments relate to contractual obligations for capacity rights with third-party pipelines and processing facilities. Drilling and Field Services commitments represent minimum future expenditures for drilling, well servicing and equipment commitment rights. Significant development commitments with joint venture partners are partially satisfied by Commitments included in the table above. Operating Leases consist of various building leases used in Encana s daily operations.

Further to the commitments disclosed above, Encana also has various obligations that become payable if certain events occur including variable interests arising from gathering and compression agreements and guarantees on transportation commitments resulting from completed property divestitures as described in Notes 17 and 24, respectively, to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

In addition, Encana has purchase orders for the purchase of inventory and other goods and services, which typically represent authorization to purchase rather than binding agreements. Encana also has obligations to fund its defined benefit pension and other post-employment benefit plans, as well as unrecognized tax benefits where the settlement is not expected within the next 12 months as described in Notes 20 and 6, respectively, to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Encana may have potential exposures related to previously divested properties where the purchasers typically assume all obligations to plug, abandon, and decommission the associated wells, structures, and facilities acquired. One or more of the counterparties in these transactions could, either as a result of the severe decline in oil and natural gas prices or other factors related to the historical or future operations of their respective businesses, face financial problems that may have a significant impact on their solvency and ability to continue as a going concern. If a purchaser becomes the subject of a proceeding under relevant insolvency laws or otherwise fails to perform required abandonment obligations, Encana could be required to perform such actions under applicable federal laws and regulations. While the Company believes that the risk of such event occurring is low, the Company could be forced to use available cash to cover the costs of such liabilities and obligations should they arise.

Contingencies

For information on contingencies, refer to Note 24 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Table of Contents

Critical Accounting Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. For a discussion of the Company s significant accounting policies refer to Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining Encana s financial results. Changes in the estimates and assumptions discussed below could materially affect the amount or timing of the financial results of the Company.

Description	Judgments and Uncertainties
Upstream Assets and Reserve Estimates	
As Encana follows full cost accounting for oil, NGL and natural gas activities, reserves estimates are a key input to the Company s depletion, gain or loss on divestitures and ceiling test impairment calculations. In addition, these reserves are the basis for the Company s supplemental oil and gas disclosures.	Due to the inter-relationship of various judgments made to reserve estimates and the volatile nature of commodity prices, it is generally not possible to predict the timing or magnitude of ceiling test impairments.
Encana estimates its proved oil and gas reserves according to the definition of proved reserves provided by the SEC. The Company s estimates of proved reserves are made using available geological and reservoir data as well as production performance data and must demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods and government regulations. The estimation of reserves is a subjective process.	Revisions to reserve estimates are necessary due to changes in and among other things, development plans, projected future rates of production, the timing of future expenditures, reservoir performance, economic conditions, governmental restrictions as well as changes in the expected recovery associated with infill drilling, all of which are subject to numerous uncertainties and various interpretations. Downward revisions in proved reserve estimates due to changes in reserve estimates may increase depletion expense and may also result in a ceiling test impairment.
Reserves are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by	Decreases in prices may result in reductions in certain proved reserves due to reaching economic limits at an earlier projected date and impact earnings through depletion expense and ceiling test impairments.

contractual arrangements.

Encana manages its business using estimates of reserves and resources based on forecast prices and costs as it gives consideration to probable and possible reserves and future changes in commodity prices.

Encana believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana s oil and natural gas properties or the future net cash flows expected to be generated from such properties.

Business Combinations

Encana follows the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the fair value amounts assigned to assets and liabilities is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in net earnings.

The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. The assumptions made in performing these valuations include discount rates, future commodity prices and costs, the timing of development activities, projections of oil and gas reserves, estimates to abandon and reclaim producing wells and tax amortization benefits available to a market participant. Changes in key assumptions may cause the acquisition accounting to be revised, including the recognition of additional goodwill or discount on acquisition. There is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected.

Fair value estimates are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. When market-observable prices are not available to value assets and liabilities, the Company may use the cost, income, or market valuation approaches depending on the quality of information available to support management s assumptions.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future through impairments of goodwill. In addition, differences between the future commodity prices when acquiring assets and the historical 12-month average trailing price to calculate ceiling test impairments of upstream assets may impact net earnings.

Table of Contents

Description	Judgments and Uncertainties
Goodwill Impairments	
Goodwill is assessed for impairment at least annually in December, at the reporting unit level which are Encana s country cost centres. To assess whether goodwill is impaired, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value, then goodwill is measured and written down to the reporting unit s implied fair value of goodwill. The implied fair value of goodwill is determined by deducting the fair value of the reporting unit s assets and liabilities from the fair value of the reporting unit as if the reporting entity had been acquired in a business combination. Any excess of the carrying value of goodwill over the implied fair value of goodwill is recognized as an impairment and charged to net earnings.	The most significant assumptions used to determine a reporting unit s fair value include estimations of oil and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves, estimates of market prices considering forward commodity price curves as of the measurement date, market discount rates and estimates of operating, administrative, and capital costs adjusted for inflation. In addition, management may support fair value estimates determined with comparable companies that are actively traded in the public market, recent comparable asset transactions, and transaction premiums. This would require management to make certain judgments about the selection of comparable companies utilized.
Because quoted market prices for the Company s reporting units are not available, management applies judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests. Encana may use a combination of the income and the market valuation approaches.	Downward revisions of estimated reserves quantities, increases in future cost estimates, sustained decreases in oil or natural gas prices, or divestiture of a significant component of the reporting unit could reduce expected future cash flows and fair value estimates of the reporting units and possibly result in an impairment of goodwill in future periods.
Encana has assessed its goodwill for impairment at December 31, 2017 and no impairment was recognized as there were no indicators of impairment. The reporting units fair values were substantially in excess of the carrying values and as a result was not at risk of failing step one of the impairment test as at December 31, 2017.	
Asset Retirement Obligation	
Asset retirement obligations are those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, an offshore production platform, processing plants, and restoring land or seabed at the end of oil and gas production operations. The fair value of estimated asset retirement obligations is recognized on the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the initially estimated fair value of the asset	Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations. 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 such factors as reserves lives, retirement costs, timing of settlements, credit-adjusted risk-free rates and inflation rates. Changes in these estimates impact net earnings through accretion of the asset retirement obligation in

retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation are recognized as a change in the asset retirement obligation and the related asset retirement cost. Actual expenditures incurred are charged against the accumulated asset retirement obligation. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

addition to depletion of the asset retirement cost included in property, plant and equipment.

Derivative Financial Instruments

Encana uses derivative financial instruments to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company s policy is not to utilize derivative financial instruments for speculative purposes. Realized gains or losses from financial derivatives are recognized in net earnings as the contracts are settled. Unrealized gains and losses are recognized in net earnings at the end of each respective reporting period based on the changes in fair value of the contracts.

Encana s derivative financial instruments primarily relate to commodities including oil, NGLs, natural gas and power. The most significant assumptions used in determining the fair value to the Company s commodity derivatives financial instruments include estimates of future commodity prices, implied volatilities of commodity prices, discount rates and estimates of counterparty credit risk. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as regional price differentials. Changes in these estimates and assumptions can impact net earnings through decreased revenues or increased expenses.

Derivative financial instruments are measured at fair value with changes in fair value recognized in net earnings. Fair value estimates are determined using quoted prices in active markets, inferred based on market prices of similar assets and liabilities or valued using internally developed estimates. The Company may use various valuation techniques including the discounted cash flow or option valuation models.

As Encana has chosen not to elect hedge accounting treatment for the Company s derivative financial instruments, changes in the fair values of derivative financial instruments can have a significant impact on Encana s results of operations.

Table of Contents

Description	Judgments and Uncertainties
Generally, changes in fair values of derivative financial instruments do not impact the Company s liquidity or capital resources. Settlements of derivative financial instruments do have an impact on the Company s liquidity and results of operation.	
Income Taxes	
Encana follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the enacted income tax rates and laws expected to apply when the assets are realized and liabilities are settled. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates and laws enacted at the end of the reporting period. The effect of a change in the enacted tax rates or laws is recognized in net earnings in the period of enactment.	Tax interpretations, regulations and legislation, including U.S. Tax Reform and potential Treasury Department regulations and guidance, in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense arising from the changes in deferred income tax assets or liabilities.
Deferred income tax assets are routinely assessed for realizability. If it is more likely than not that deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets.	Encana considers available positive and negative evidence when assessing the realizability of deferred tax assets, including historic and expected future taxable earnings, available tax planning strategies and carry forward periods. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions, particularly related to oil and gas prices. As a result, the assumptions used in determining expected future taxable earnings are consistent with those used in the goodwill impairment assessment.
Encana s interim income tax expense is determined using an estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods.	The estimated annual effective income tax rate is impacted by expected annual earnings, statutory rate and other foreign differences, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding.
Encana recognizes the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. A recognized tax position is initially and subsequently measured as the	The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals are adjusted based on changes in facts and circumstances. Material changes to Encana s income tax accruals may occur in the future based on

largest amount of tax benefit that is greater than 50 percent likely of being realized upon settlement with a taxing authority. Liabilities for unrecognized tax benefits that are not expected to be settled within the next 12 months are included in other liabilities and provisions.	the progress of ongoing audits, changes in legislation or resolution of pending matters.
Encana s unremitted earnings from its foreign subsidiaries are considered to be permanently reinvested outside of Canada, as a result the Company does not calculate a deferred tax liability for Canadian income taxes on these earnings.	Determination of unrecognized deferred income tax liabilities is not practicable due to the significant uncertainty in assumptions that would be required including determining the nature of any future remittances, that could be distributions in the form of non-taxable returns of capital or taxable earnings and associated withholding taxes, or determining the tax rates on any future remittances that could vary significantly depending on the available approaches to repatriate the earnings.

Recent Accounting Pronouncements

For recently issued accounting policies, refer to Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Table of Contents

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be viewed as a substitute for measures reported under U.S. GAAP. These measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company s liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Non-GAAP Cash Flow, Non-GAAP Cash Flow Margin and Debt to Adjusted Capitalization. Management s use of these measures is discussed further below.

Non-GAAP Cash Flow and Non-GAAP Cash Flow Margin

Non-GAAP Cash Flow is a non-GAAP measure defined as cash from (used in) operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets.

Non-GAAP Cash Flow Margin is a non-GAAP measure defined as Non-GAAP Cash Flow per BOE of production.

Management believes these measures are useful to the Company and its investors as a measure of operating and financial performance across periods and against other companies in the industry, and are an indication of the Company s ability to generate cash to finance capital programs, to service debt and to meet other financial obligations. These measures are used, along with other measures, in the calculation of certain performance targets for the Company s management and employees.

($ millions, except as indicated)		**2017**		2016		2015
Cash From (Used in) Operating Activities	**$**	**1,050**	$	625	$	1,681
(Add back) deduct:						
Net change in other assets and liabilities		**(40)**		(26)		(11)
Net change in non-cash working capital		**(253)**		(187)		262
Current tax on sale of assets		**-**		-		-
Non-GAAP Cash Flow	**$**	**1,343**	$	838	$	1,430
Production Volumes (MMBOE)		**114.3**		129.1		148.2
Non-GAAP Cash Flow Margin ($/BOE) [(1)]	**$**	**11.75**	$	6.49	$	9.65

(1) Non-GAAP Cash Flow Margin was previously presented as Corporate Margin.

Debt to Adjusted Capitalization

Debt to Adjusted Capitalization is a non-GAAP measure which adjusts capitalization for historical ceiling test impairments that were recorded as at December 31, 2011. Management monitors Debt to Adjusted Capitalization as a proxy for Encana s financial covenant under the Credit Facilities which require debt to adjusted capitalization to be less than 60 percent. Adjusted Capitalization includes debt, total shareholders equity and an equity adjustment for cumulative historical ceiling test impairments recorded as at December 31, 2011 in conjunction with the Company s January 1, 2012 adoption of U.S. GAAP.

($ millions, except as indicated)	**December 31, 2017**	December 31, 2016	December 31, 2015
Debt	**$ 4,197**	$ 4,198	$ 5,333
Total Shareholders Equity	**6,728**	6,126	6,167
Equity Adjustment for Impairments at December 31, 2011	**7,746**	7,746	7,746
Adjusted Capitalization	**$ 18,671**	$ 18,070	$ 19,246
Debt to Adjusted Capitalization	**22%**	23%	28%

Table of Contents

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Encana s potential exposure to market risks. The term market risk refers to the Company s risk of loss arising from adverse changes in oil, NGL and natural gas prices, foreign currency exchange rates and interest rates. The following disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how the Company views and manages ongoing market risk exposures. The Company s policy is to not use derivative financial instruments for speculative purposes.

COMMODITY PRICE RISK

Commodity price risk arises from the effect fluctuations in future commodity prices, including oil, NGLs and natural gas, may have on future revenues, expenses and cash flows. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to the Company s natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable as discussed in Item 1A. Risk Factors of this Annual Report on Form 10-K. To partially mitigate exposure to commodity price risk, the Company may enter into various derivative financial instruments including futures, forwards, swaps, options and costless collars. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors and may vary from time to time. Both exchange traded and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company s derivative and financial instruments, see Note 22 under Part II, Item 8 of this Annual Report on Form 10-K.

The table below summarizes the sensitivity of the fair value of the Company s risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting pre-tax net earnings as follows:

	December 31, 2017	
(US$ millions)	10% Price Increase	10% Price Decrease
Crude oil price	$ (207)	$ 198
Natural gas price	36	(40)

FOREIGN EXCHANGE RISK

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company s financial assets or liabilities. As Encana operates in Canada and the United States, fluctuations in the exchange rate between the U.S. and Canadian dollars can have a significant effect on the Company s reported results. Although Encana s financial results are consolidated in Canadian dollars, the Company reports its results in U.S. dollars as most of its revenues are closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies.

66

Table of Contents

The table below summarizes selected foreign exchange impacts on Encana s financial results when compared to the same periods in the prior years.

	2017		2016		2015	
	$ millions	$/BOE	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:						
Capital Investment	**$ 7**		$ (25)		$ (168)	
Transportation and Processing Expense [1]	**11**	**$ 0.10**	(25)	$ (0.19)	(111)	$ (0.75)
Operating Expense [1]	**4**	**0.03**	(5)	(0.04)	(36)	(0.24)
Administrative Expense	**4**	**0.03**	(7)	(0.05)	(24)	(0.16)
Depreciation, Depletion and Amortization [1]	**5**	**0.05**	(13)	(0.10)	(84)	(0.57)

(1) Reflects upstream operations.

Foreign exchange gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated and settled, and primarily include:

- U.S. dollar denominated financing debt issued from Canada
- U.S. dollar denominated risk management assets and liabilities held in Canada
- U.S. dollar denominated cash and short-term investments held in Canada
- Foreign denominated intercompany loans

To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at December 31, 2017, Encana has entered into $650 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7597 to C$1, which mature monthly throughout 2018.

As at December 31, 2017, Encana had $4.2 billion in U.S. dollar long-term debt and $314 million in U.S. dollar capital leases issued from Canada that were subject to foreign exchange exposure.

The table below summarizes the sensitivity to foreign exchange rate fluctuations, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact from Canadian to U.S. foreign currency exchange rate changes. Fluctuations in foreign currency exchange rates could have resulted in unrealized gains (losses) impacting pre-tax net earnings as follows:

December 31, 2017

(US$ millions)		10% Rate Increase		10% Rate Decrease
Foreign currency exchange	$	(233)	$	285

INTEREST RATE RISK

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company s financial assets or liabilities. The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt and may also enter into interest rate derivatives to partially mitigate effects of fluctuations in market interest rates.

As at December 31, 2017, the Company had no floating rate debt and there were no interest rate derivatives outstanding.

Table of Contents

Item 8: Financial Statements and Supplementary Data

Management Report

Management s Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Encana Corporation (the Company) are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in United States dollars in accordance with generally accepted accounting principles in the United States and include certain estimates that reflect Management s best judgments.

The Company s Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the requirements of Canadian and United States securities legislation and the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets at least on a quarterly basis.

Management s Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company s financial reporting. The internal control system was designed to provide reasonable assurance to the Company s Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of the Company s internal control over financial reporting as at December 31, 2017. In making its assessment, Management has used the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission to evaluate the effectiveness of the Company s internal control over financial reporting. Based on our evaluation, Management has concluded that the Company s internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, was appointed by a vote of shareholders at the Company s last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company s internal control over financial reporting as at December 31, 2017, as stated in their Auditor s Report. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Douglas J. Suttles
Douglas J. Suttles
President &
Chief Executive Officer

/s/ Sherri A. Brillon
Sherri A. Brillon
Executive Vice-President &
Chief Financial Officer

February 26, 2018

Table of Contents

Auditor s Report

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Encana Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying Consolidated Balance Sheet of Encana Corporation and its subsidiaries as of December 31, 2017 and 2016, and the related Consolidated Statements of Earnings, Comprehensive Income, Changes in Shareholders Equity and Cash Flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the Consolidated Financial Statements). We also have audited the Company s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company s management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company s Consolidated Financial Statements and on the Company s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the Consolidated Financial Statements included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements.

Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements. Our audit of internal control over

financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Table of Contents

Definition and Limitations of Internal Control over Financial Reporting

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada

February 26, 2018

We have served as the auditor of the Company or its predecessor since 1958.

Table of Contents

Consolidated Statement of Earnings

For the years ended December 31 (US$ millions, except per share amounts)		2017	2016	2015
Revenues	*(Note 2)*			
Product revenues		**$ 2,999**	$ 2,443	$ 3,350
Gains (losses) on risk management, net	*(Note 22)*	**482**	(275)	592
Market optimization		**863**	647	368
Other		**99**	103	112
Total Revenues		**4,443**	2,918	4,422
Operating Expenses	*(Note 2)*			
Production, mineral and other taxes		**112**	99	144
Transportation and processing	*(Note 22)*	**845**	901	1,252
Operating	*(Notes 19, 20)*	**506**	598	723
Purchased product		**788**	586	323
Depreciation, depletion and amortization		**833**	859	1,488
Impairments	*(Note 8)*	**-**	1,396	6,473
Accretion of asset retirement obligation	*(Note 14)*	**37**	51	45
Administrative	*(Notes 18, 19, 20)*	**254**	309	275
Total Operating Expenses		**3,375**	4,799	10,723
Operating Income (Loss)		**1,068**	(1,881)	(6,301)
Other (Income) Expenses				
Interest	*(Notes 4, 12)*	**363**	397	614
Foreign exchange (gain) loss, net	*(Notes 5, 22)*	**(279)**	(210)	1,082
(Gain) loss on divestitures, net	*(Note 3)*	**(404)**	(390)	(14)
Other (gains) losses, net	*(Notes 12, 20)*	**(42)**	(58)	27
Total Other (Income) Expenses		**(362)**	(261)	1,709
Net Earnings (Loss) Before Income Tax		**1,430**	(1,620)	(8,010)
Income tax expense (recovery)	*(Note 6)*	**603**	(676)	(2,845)
Net Earnings (Loss)		**$ 827**	$ (944)	$ (5,165)
Net Earnings (Loss) per Common Share				
Basic & Diluted	*(Note 15)*	**$ 0.85**	$ (1.07)	$ (6.28)
Dividends Declared per Common Share	*(Note 15)*	**$ 0.06**	$ 0.06	$ 0.28
Weighted Average Common Shares Outstanding (millions)				
Basic & Diluted	*(Note 15)*	**973.1**	882.6	822.1

Consolidated Statement of Comprehensive Income

For the years ended December 31 (US$ millions)		2017	2016	2015
Net Earnings (Loss)		**$ 827**	$ (944)	$ (5,165)
Other Comprehensive Income (Loss), Net of Tax				
Foreign currency translation adjustment	*(Note 16)*	**(171)**	(183)	668
Pension and other post-employment benefit plans	*(Notes 16, 20)*	**3**	3	33
Other Comprehensive Income (Loss)		**(168)**	(180)	701
Comprehensive Income (Loss)		**$ 659**	$ (1,124)	$ (4,464)

See accompanying Notes to Consolidated Financial Statements

Table of Contents

Consolidated Balance Sheet

As at December 31 (US$ millions)		2017	2016
Assets			
Current Assets			
Cash and cash equivalents		**$ 719**	$ 834
Accounts receivable and accrued revenues	*(Note 7)*	**774**	663
Risk management	*(Notes 21, 22)*	**205**	-
Income tax receivable		**573**	426
		2,271	1,923
Property, Plant and Equipment, at cost:	*(Note 8)*		
Oil and natural gas properties, based on full cost accounting			
Proved properties		**40,228**	39,610
Unproved properties		**4,480**	5,198
Other		**2,302**	2,194
Property, plant and equipment		**47,010**	47,002
Less: Accumulated depreciation, depletion and amortization		**(38,056)**	(38,863)
Property, plant and equipment, net	*(Note 2)*	**8,954**	8,139
Other Assets	*(Note 9)*	**144**	138
Risk Management	*(Notes 21, 22)*	**246**	16
Deferred Income Taxes	*(Note 6)*	**1,043**	1,658
Goodwill	*(Notes 2, 3, 10)*	**2,609**	2,779
	(Note 2)	**$ 15,267**	$ 14,653
Liabilities and Shareholders Equity			
Current Liabilities			
Accounts payable and accrued liabilities	*(Note 11)*	**$ 1,415**	$ 1,303
Income tax payable		**7**	5
Risk management	*(Notes 21, 22)*	**236**	254
		1,658	1,562
Long-Term Debt	*(Note 12)*	**4,197**	4,198
Other Liabilities and Provisions	*(Note 13)*	**2,167**	2,047
Risk Management	*(Notes 21, 22)*	**13**	35
Asset Retirement Obligation	*(Note 14)*	**470**	654

Deferred Income Taxes	*(Note 6)*	**34**	31
		8,539	8,527
Commitments and Contingencies	*(Note 24)*		
Shareholders Equity			
Share capital - authorized unlimited common shares 2017 issued and outstanding: 973.1 million shares (2016: 973.0 million shares)	*(Note 15)*	**4,757**	4,756
Paid in surplus		**1,358**	1,358
Accumulated deficit		**(429)**	(1,198)
Accumulated other comprehensive income	*(Note 16)*	**1,042**	1,210
Total Shareholders Equity		**6,728**	6,126
		$ 15,267	$ 14,653

See accompanying Notes to Consolidated Financial Statements

Approved by the Board of Directors

/s/ Clayton H. Woitas
Clayton H. Woitas
Director

/s/ Bruce G. Waterman
Bruce G. Waterman
Director

Table of Contents

Consolidated Statement of Changes in Shareholders Equity

For the year ended December 31, 2017 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders Equity
Balance, December 31, 2016		**$ 4,756**	**$ 1,358**	**$ (1,198)**	**$ 1,210**	**$ 6,126**
Net Earnings (Loss)		**-**	**-**	**827**	**-**	**827**
Dividends on Common Shares	*(Note 15)*	**-**	**-**	**(58)**	**-**	**(58)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 15)*	**1**	**-**	**-**	**-**	**1**
Other Comprehensive Income (Loss)	*(Note 16)*	**-**	**-**	**-**	**(168)**	**(168)**
Balance, December 31, 2017		**$ 4,757**	**$ 1,358**	**$ (429)**	**$ 1,042**	**$ 6,728**

For the year ended December 31, 2016 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders Equity
Balance, December 31, 2015		$ 3,621	$ 1,358	$ (202)	$ 1,390	$ 6,167
Net Earnings (Loss)		-	-	(944)	-	(944)
Dividends on Common Shares	*(Note 15)*	-	-	(52)	-	(52)
Common Shares Issued	*(Note 15)*	1,134	-	-	-	1,134
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 15)*	1	-	-	-	1
Other Comprehensive Income (Loss)	*(Note 16)*	-	-	-	(180)	(180)
Balance, December 31, 2016		$ 4,756	$ 1,358	$ (1,198)	$ 1,210	$ 6,126

For the year ended December 31, 2015 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders Equity
Balance, December 31, 2014		$ 2,450	$ 1,358	$ 5,188	$ 689	$ 9,685
Net Earnings (Loss)		-	-	(5,165)	-	(5,165)

Dividends on Common Shares	*(Note 15)*	-	-	(225)	-	(225)
Common Shares Issued	*(Note 15)*	1,098	-	-	-	1,098
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 15)*	73	-	-	-	73
Other Comprehensive Income (Loss)	*(Note 16)*	-	-	-	701	701
Balance, December 31, 2015		$ 3,621	$ 1,358	$ (202)	$ 1,390	$ 6,167

See accompanying Notes to Consolidated Financial Statements

Table of Contents

Consolidated Statement of Cash Flows

For the years ended December 31 (US$ millions)		2017	2016	2015
Operating Activities				
Net earnings (loss)		**$ 827**	$ (944)	$ (5,165)
Depreciation, depletion and amortization		**833**	859	1,488
Impairments	*(Note 8)*	**-**	1,396	6,473
Accretion of asset retirement obligation	*(Note 14)*	**37**	51	45
Deferred income taxes	*(Note 6)*	**666**	(598)	(2,811)
Unrealized (gain) loss on risk management	*(Note 22)*	**(442)**	614	331
Unrealized foreign exchange (gain) loss	*(Note 5)*	**(291)**	(140)	687
Foreign exchange on settlements	*(Note 5)*	**24**	(68)	358
(Gain) loss on divestitures, net	*(Note 3)*	**(404)**	(390)	(14)
Other		**93**	58	38
Net change in other assets and liabilities		**(40)**	(26)	(11)
Net change in non-cash working capital	*(Note 23)*	**(253)**	(187)	262
Cash From (Used in) Operating Activities		**1,050**	625	1,681
Investing Activities				
Capital expenditures	*(Note 2)*	**(1,796)**	(1,132)	(2,232)
Acquisitions	*(Note 3)*	**(54)**	(210)	(70)
Proceeds from divestitures	*(Note 3)*	**736**	1,262	1,908
Net change in investments and other		**77**	51	(271)
Cash From (Used in) Investing Activities		**(1,037)**	(29)	(665)
Financing Activities				
Net issuance (repayment) of revolving long-term debt	*(Note 12)*	**-**	(650)	(627)
Repayment of long-term debt	*(Note 12)*	**-**	(400)	(1,302)
Issuance of common shares, net of offering costs	*(Note 15)*	**-**	1,129	1,088
Dividends on common shares	*(Note 15)*	**(57)**	(51)	(152)
Capital lease payments and other financing arrangements	*(Note 13)*	**(82)**	(66)	(61)
Cash From (Used in) Financing Activities		**(139)**	(38)	(1,054)

Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**11**		5		(29)
Increase (Decrease) in Cash and Cash Equivalents	**(115)**		563		(67)
Cash and Cash Equivalents, Beginning of Year	**834**		271		338
Cash and Cash Equivalents, End of Year	**$ 719**	$	834	$	271
Cash, End of Year	**$ 51**	$	78	$	58
Cash Equivalents, End of Year	**668**		756		213
Cash and Cash Equivalents, End of Year	**$ 719**	$	834	$	271

Supplementary Cash Flow Information *(Note 23)*

See accompanying Notes to Consolidated Financial Statements

Table of Contents

A) NATURE OF OPERATIONS

Encana is in the business of the exploration for, the development of, and the production and marketing of oil, NGLs and natural gas.

B) BASIS OF PRESENTATION

The Consolidated Financial Statements include the accounts of Encana and are presented in conformity with U.S. GAAP and the rules and regulations of the SEC.

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in U.S. dollars. Encana s financial results are consolidated in Canadian dollars; however, the Company has adopted the U.S. dollar as its reporting currency to facilitate a more direct comparison to other North American oil and gas companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

C) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of Encana and entities in which it holds a controlling interest. All intercompany balances and transactions are eliminated on consolidation. Undivided interests in oil and natural gas exploration and production joint ventures and partnerships are consolidated on a proportionate basis. Investments in non-controlled entities over which Encana has the ability to exercise significant influence are accounted for using the equity method.

D) FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings. Foreign currency revenues and expenses are translated at the rates of exchange in effect at the time of the transaction.

Assets and liabilities of foreign operations are translated at period end exchange rates, while the related revenues and expenses are translated using average rates during the period. Translation gains and losses relating to the foreign operations are included in accumulated other comprehensive income (AOCI). Recognition of Encana s accumulated translation gains and losses into net earnings occurs upon complete or substantially complete liquidation of the Company s investment in the foreign operation.

For financial statement presentation, assets and liabilities are translated into the reporting currency at period end exchange rates, while revenues and expenses are translated using average rates over the period. Gains and losses relating to the financial statement translation are included in AOCI.

E) USE OF ESTIMATES

Preparation of the Consolidated Financial Statements in conformity with U.S. GAAP requires Management to make informed estimates and assumptions and use judgments that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future events occur.

Table of Contents

Significant items subject to estimates and assumptions are:

- Estimates of proved reserves used for depletion and ceiling test impairment calculations
- Estimated fair value of long-term assets used for impairment calculations
- Fair value of reporting units used for the assessment of goodwill
- Estimates of future taxable earnings used to assess the realizable value of deferred tax assets
- Fair value of asset retirement costs and related obligations
- Fair value of derivative instruments
- Fair value attributed to assets acquired and liabilities assumed in business combinations
- Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate
- Accruals for long-term performance-based compensation arrangements, including whether or not the performance criteria will be met and measurement of the ultimate payout amount
- Recognized values of pension assets and obligations, as well as the pension costs charged to net earnings, depend on certain actuarial and economic assumptions
- Accruals for legal claims, environmental risks and exposures

F) REVENUE RECOGNITION

Revenues associated with Encana s oil, NGLs and natural gas are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is probable. Revenues are presented on an after-royalties basis. Realized gains and losses from the Company s financial derivatives related to oil and natural gas commodity prices are recognized in revenues when the contract is settled. Unrealized gains and losses related to these contracts are recognized in revenues based on the changes in fair value of the contracts at the end of the respective periods.

Market optimization revenues and purchased product expenses are recorded on a gross basis when Encana takes title to the product and has the risks and rewards of ownership. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided where Encana acts as agent are recorded as the services are provided.

Other revenues primarily include sublease rentals. Sublease rentals are recognized straight-line over the lease term.

G) PRODUCTION, MINERAL AND OTHER TAXES

Costs paid by Encana for taxes based on production or revenues from oil, NGLs and natural gas are recognized when the product is produced. Costs paid by Encana for taxes on the valuation of upstream assets and reserves are recognized when incurred.

H) TRANSPORTATION AND PROCESSING

Costs paid by Encana for the transportation and processing of oil, NGLs and natural gas are recognized when the product is delivered and the services made available or provided.

I) OPERATING

Operating costs paid by Encana, net of amounts capitalized, for oil and natural gas properties in which the Company has a working interest.

Table of Contents

J) EMPLOYEE BENEFIT PLANS

The Company sponsors defined contribution and defined benefit plans, providing pension and other post-employment benefits to its employees in Canada and the U.S. As of January 1, 2003, the defined benefit pension plan was closed to new entrants.

Pension expense for the defined contribution pension plan is recorded as the benefits are earned by the employees covered by the plans. Encana accrues for its obligations under its employee defined benefit plans, net of plan assets. The cost of defined benefit pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service and reflects Management s best estimate of salary escalation, mortality rates, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on historical and projected rates of return for assets in the investment plan portfolio. The actual return is based on the fair value of plan assets. The projected benefit obligation is discounted using the market interest rate on high-quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments, the amortization of net prior service costs, and the amortization of the excess of the net actuarial gains or losses over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is on a straight-line basis over a period covering the expected average remaining service lives of employees covered by the plans. Actuarial gains and losses related to the change in the over-funded or under-funded status of the defined benefit pension plan and other post-employment benefit plans are recognized in other comprehensive income.

K) INCOME TAXES

Encana follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the enacted income tax rates and laws expected to apply when the assets are realized and liabilities are settled. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxing authorities based on the income tax rates and laws enacted at the end of the reporting period. The effect of a change in the enacted tax rates or laws is recognized in net earnings in the period of enactment. Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders equity, in which case the income taxes are recognized directly in shareholders equity.

Deferred income tax assets are assessed routinely for realizability. If it is more likely than not that deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets. Encana considers available positive and negative evidence when assessing the realizability of deferred tax assets including historic and expected future taxable earnings, available tax planning strategies and carry forward periods. The assumptions used in determining expected future taxable earnings are consistent with those used in the goodwill impairment assessment.

Encana recognizes the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. A recognized tax position is initially and subsequently measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon settlement with a taxing authority. Liabilities for unrecognized tax benefits that are not expected to be settled within the next 12 months are included in other liabilities and provisions. Interest related to unrecognized tax benefits is recognized in interest expense.

L) EARNINGS PER SHARE AMOUNTS

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per common share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised, fully vested, or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to repurchase common shares at the average market price.

Table of Contents

M) CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand and short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased. Outstanding disbursements issued in excess of applicable bank account balances are excluded from cash and cash equivalents and are recorded in accounts payable and accrued liabilities.

N) PROPERTY, PLANT AND EQUIPMENT

UPSTREAM

Encana uses the full cost method of accounting for its acquisition, exploration and development activities. Accordingly, all costs directly associated with the acquisition of, the exploration for, and the development of oil, NGLs and natural gas reserves, including costs of undeveloped leaseholds, dry holes and related equipment, are capitalized on a country-by-country cost centre basis. Capitalized costs exclude costs relating to production, general overhead or similar activities.

Capitalized costs accumulated within each cost centre are depleted using the unit-of-production method based on proved reserves. Depletion is calculated using the capitalized costs, including estimated retirement costs, plus the undiscounted future expenditures, based on current costs, to be incurred in developing proved reserves.

Costs associated with unproved properties are excluded from the depletion calculation until it is determined that proved reserves are attributable or impairment has occurred. Unproved properties are assessed separately for impairment on a quarterly basis. Costs that have been impaired are included in the costs subject to depletion within the full cost pool.

Under the full cost method of accounting, the carrying amount of Encana s oil and natural gas properties within each country cost centre is subject to a ceiling test at the end of each quarter. A ceiling test impairment is recognized in net earnings when the carrying amount of a country cost centre exceeds the country cost centre ceiling. The carrying amount of a cost centre includes capitalized costs of proved oil and natural gas properties, net of accumulated depletion and the related deferred income taxes.

The cost centre ceiling is the sum of the estimated after-tax future net cash flows from proved reserves, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs. The 12-month average trailing price is calculated as the average of the price on the first day of each month within the trailing 12-month period. Any excess of the carrying amount over the calculated ceiling amount is recognized as an impairment in net earnings.

Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction significantly alters the relationship between capitalized costs and proved reserves in the cost centre, in which case a gain or loss is recognized in net earnings. Generally, a gain or loss on a divestiture would be recognized when 25 percent or more of the Company s proved reserves quantities in a particular country are sold. For divestitures that result in the recognition of a gain or loss on the sale and constitute a business, goodwill is allocated to the divestiture.

CORPORATE

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Costs associated with The Bow office building are carried at cost and depreciated on a straight-line basis over the 60-year estimated life of the building. Assets under construction are not subject to depreciation until put into use. Land is carried at cost.

Table of Contents

O) CAPITALIZATION OF COSTS

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Interest on borrowings associated with major development projects is capitalized during the construction phase.

P) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. The acquired identifiable net assets are measured at fair value at the date of acquisition. Deferred taxes are recognized for any differences between the fair value of net assets acquired and the related tax bases. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in net earnings. Associated transaction costs are expensed when incurred.

Q) GOODWILL

Goodwill represents the excess of purchase price over fair value of net assets acquired and is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units, which are Encana s country cost centres. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit, including goodwill, is higher than its related fair value then goodwill is written down to the reporting unit s implied fair value of goodwill. The implied fair value of goodwill is determined by deducting the fair value of the reporting unit s assets and liabilities from the fair value of the reporting unit as if the reporting entity had been acquired in a business combination. Any excess of the carrying value of goodwill over the implied fair value of goodwill is recognized as an impairment and charged to net earnings. Subsequent measurement of goodwill is at cost less any accumulated impairments.

R) IMPAIRMENT OF LONG-TERM ASSETS

The carrying value of long-term assets, excluding goodwill and upstream assets included in property, plant and equipment, is assessed for impairment when indicators suggest that the carrying value of an asset or asset group may not be recoverable. If the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the continued use and eventual disposition of the asset or asset group, an impairment is recognized for the excess of the carrying amount over its estimated fair value.

S) ASSET RETIREMENT OBLIGATION

Asset retirement obligations are those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, an offshore production platform, processing plants, and restoring land or seabed at the end of oil and gas production operations. The asset retirement obligation is initially measured at its fair value and recorded as a liability with an offsetting retirement cost that is capitalized as part of the related long-lived asset on the Consolidated Balance Sheet. The estimated fair value is measured by reference to the expected future cash flows required to satisfy the obligation, discounted at the Company s credit-adjusted risk-free rate. Changes in the estimated obligation resulting from revisions to estimated timing or amount of future cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligations resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated asset retirement obligation.

Table of Contents

T) STOCK-BASED COMPENSATION

Obligations for payments of cash or common shares under Encana s stock-based compensation plans are accrued over the vesting period, net of forfeitures, using fair values. Fair values are determined using observable share prices and/or pricing models such as the Black-Scholes-Merton option-pricing model. For equity-settled stock-based compensation plans, fair values are determined at the grant date and are recognized over the vesting period as compensation costs with a corresponding credit to shareholders equity. For cash-settled stock-based compensation plans, fair values are determined at each reporting date and periodic changes are recognized as compensation costs, with a corresponding change to liabilities.

U) LEASES

Leases entered into for the use of an asset are classified as either capital or operating leases. Capital leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased item. Capital leases are capitalized upon commencement of the lease term at the lower of the fair value of the leased asset or the present value of the minimum lease payments. Capitalized leased assets are amortized over the estimated useful life of the asset if the lease arrangement contains a bargain purchase option or ownership of the leased asset transfers at the end of the lease term. Otherwise, the leased assets are amortized over the lease term. Amortization of capitalized leased assets is included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. All other leases are classified as operating leases and the payments are recognized on a straight-line basis over the lease term.

V) FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques include the market, income and cost approach. The market approach uses information generated by market transactions involving identical or comparable assets or liabilities; the income approach converts estimated future amounts to a present value; the cost approach is based on the amount that currently would be required to replace an asset.

Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair value hierarchy are as follows:

- Level 1 - Inputs represent quoted prices in active markets for identical assets or liabilities, such as exchange-traded commodity derivatives.

- Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.

- Level 3 - Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

In determining fair value, the Company utilizes the most observable inputs available. If a fair value measurement reflects inputs at multiple levels within the hierarchy, the fair value measurement is characterized based on the lowest

level of input that is significant to the fair value measurement.

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reported on the Consolidated Balance Sheet approximates fair value. The fair value of long-term debt is disclosed in Note 12. Fair value information related to pension plan assets is included in Note 20. Recurring fair value measurements are performed for risk management assets and liabilities and other derivative contracts as discussed in Note 21.

Certain non-financial assets and liabilities are initially measured at fair value, such as asset retirement obligations and assets and liabilities acquired in business combinations or certain non-monetary exchange transactions.

Table of Contents

W) RISK MANAGEMENT ASSETS AND LIABILITIES

Risk management assets and liabilities are derivative financial instruments used by Encana to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company s policy is not to utilize derivative financial instruments for speculative purposes.

Derivative instruments that do not qualify for the normal purchases and sales exemption are measured at fair value with changes in fair value recognized in net earnings. The fair values recorded in the Consolidated Balance Sheet reflect netting the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. Realized gains or losses from financial derivatives related to oil and natural gas commodity prices are recognized in revenues as the contracts are settled. Realized gains or losses from financial derivatives related to power commodity prices are recognized in transportation and processing expense as the related power contracts are settled. Realized gains or losses from foreign currency exchange swaps are recognized in foreign exchange (gain) loss as the contracts are settled. Realized gains or losses from other derivative contracts related to certain payment obligations are recognized in revenues as the obligations are settled. Unrealized gains and losses are recognized in revenues, transportation and processing expense and foreign exchange (gain) loss accordingly, at the end of each respective reporting period based on the changes in fair value of the contracts.

X) COMMITMENTS AND CONTINGENCIES

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change.

Y) RECENT ACCOUNTING PRONOUNCEMENTS

NEW STANDARDS ISSUED NOT YET ADOPTED

As of January 1, 2018, Encana will be required to adopt ASU 2014-09, Revenue from Contracts with Customers under Topic 606 and the related subsequent updates and clarifications issued, which will replace Topic 605, Revenue Recognition , and other industry-specific guidance in the Accounting Standards Codification. The new standard is based on the principle that revenue is recognized on the transfer of promised goods or services to customers in an amount that reflects the consideration the company expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU 2015-14, Deferral of Effective Date for Revenue from Contracts with Customers , which deferred the effective date of ASU 2014-09. The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoption. Encana has substantially completed evaluating the impact of ASU 2014-09 and currently expects that the standard will not have a material impact on the Company s Consolidated Financial Statements other than enhanced disclosures related to the disaggregation of revenues from contracts with customers, the Company s performance obligations and any significant judgments. Encana intends to adopt the new standard using the modified retrospective approach at the date of adoption.

As of January 1, 2018, Encana will be required to adopt ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost . The amendment requires the service cost component to be presented with the related employee compensation costs, while the other components of net benefit costs are required to be presented separately from the service cost component and outside the subtotal of income from operations. In

addition, the amendment allows only the service cost to be eligible for capitalization. The amendment will be applied retrospectively and provides certain practical expedients for the presentation of net periodic pension costs and net periodic postretirement benefit cost, while the capitalization of the service cost component will be applied prospectively, at the date of adoption. Encana does not expect the amendment to have a material impact on the Company s Consolidated Financial Statements.

Table of Contents

As of January 1, 2019, Encana will be required to adopt ASU 2016-02, Leases under Topic 842, which will replace Topic 840 Leases . The new standard will require lessees to recognize right-of-use assets and related lease liabilities for all leases, including leases classified as operating leases, on the Consolidated Balance Sheet. The dual classification model was retained for the purpose of subsequent measurement and presentation of leases in the Consolidated Statement of Earnings and Consolidated Statement of Cash Flows. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach, in addition Encana plans to elect certain practical expedients which will allow the Company to retain the classification of leases assessed under Topic 840 that commenced prior to adoption. Throughout 2017, Encana has been reviewing and analyzing contracts, identifying its portfolio of leased assets, and more recently has begun gathering the necessary terms and data elements that will be used to determine the impact of this standard upon adoption. The Company has also been actively identifying and evaluating the system requirements as well as processes and controls required to support the accounting for leases and related disclosures. In addition, Encana has been monitoring FASB s proposed amendments and tentative decisions for applicability and impact to the Company. Although Encana is not able to reasonably estimate the financial impact of ASU 2016-02 at this time, the Company anticipates there will be a material impact on the Company s Consolidated Financial Statements resulting from the recognition of assets and liabilities related to operating lease activities.

As of January 1, 2020, Encana will be required to adopt ASU 2017-04, Simplifying the Test for Goodwill Impairment . The amendment eliminates the second step of the goodwill impairment test which requires the Company to measure the impairment based on the excess amount of the carrying value of the reporting unit s goodwill over the implied fair value of its goodwill. Under this amendment, the goodwill impairment will be measured based on the excess amount of the reporting unit s carrying value over its respective fair value. The amendment will be applied prospectively at the date of adoption. Encana is currently in the early stages of reviewing the amendment, but does not expect the amendment to have a material impact on the Company s Consolidated Financial Statements.

Encana s reportable segments are determined based on the Company s operations and geographic locations as follows:

- **Canadian Operations** includes the exploration for, development of, and production of oil, NGLs and natural gas and other related activities within the Canadian cost centre.

- **USA Operations** includes the exploration for, development of, and production of oil, NGLs and natural gas and other related activities within the U.S. cost centre.

- **Market Optimization** is primarily responsible for the sale of the Company s proprietary production. These results are reported in the Canadian and USA Operations. Market optimization activities include third party purchases and sales of product to provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment. Market Optimization sells substantially all of the Company s upstream production to third party customers. Transactions between segments are based on market values and are eliminated on consolidation.

Corporate and Other 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 reporting segment to which the derivative instruments relate. Corporate and Other also includes amounts related to sublease rentals.

Table of Contents

Results of Operations

Segment and Geographic Information

For the years ended December 31	Canadian Operations			USA Operations			Market Optimization		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Revenues									
Product revenues	**$ 1,150**	$ 952	$ 1,309	**$ 1,849**	$ 1,491	$ 2,041	**$ -**	$ -	$ -
Gains (losses) on risk management, net	**22**	107	495	**18**	255	425	**-**	(1)	(3)
Market optimization	**-**	-	-	**-**	-	-	**863**	647	368
Other	**19**	8	18	**11**	24	25	**-**	-	-
Total Revenues	**1,191**	1,067	1,822	**1,878**	1,770	2,491	**863**	646	365
Operating Expenses									
Production, mineral and other taxes	**20**	23	28	**92**	76	116	**-**	-	-
Transportation and processing	**578**	576	654	**164**	260	580	**103**	87	12
Operating	**122**	152	152	**331**	394	519	**35**	35	33
Purchased product	**-**	-	-	**-**	-	-	**788**	586	323
Depreciation, depletion and amortization	**236**	260	305	**530**	523	1,088	**1**	-	-
Impairments	**-**	493	-	**-**	903	6,473	**-**	-	-
Total Operating Expenses	**956**	1,504	1,139	**1,117**	2,156	8,776	**927**	708	368
Operating Income (Loss)	**$ 235**	$ (437)	$ 683	**$ 761**	$ (386)	$ (6,285)	**$ (64)**	$ (62)	$ (3)

	Corporate & Other			Consolidated		
	2017	2016	2015	**2017**	2016	2015
Revenues	**$ -**	$ -	$ -	**$ 2,999**	$ 2,443	$ 3,350

Product revenues						
Gains (losses) on risk management, net	**442**	(636)	(325)	**482**	(275)	592
Market optimization	**-**	-	-	**863**	647	368
Other	**69**	71	69	**99**	103	112
Total Revenues	**511**	(565)	(256)	**4,443**	2,918	4,422
Operating Expenses						
Production, mineral and other taxes	**-**	-	-	**112**	99	144
Transportation and processing	**-**	(22)	6	**845**	901	1,252
Operating	**18**	17	19	**506**	598	723
Purchased product	**-**	-	-	**788**	586	323
Depreciation, depletion and amortization	**66**	76	95	**833**	859	1,488
Impairments	**-**	-	-	**-**	1,396	6,473
Accretion of asset retirement obligation	**37**	51	45	**37**	51	45
Administrative	**254**	309	275	**254**	309	275
Total Operating Expenses	**375**	431	440	**3,375**	4,799	10,723
Operating Income (Loss)	**$ 136**	$ (996)	$ (696)	**1,068**	(1,881)	(6,301)
Other (Income) Expenses						
Interest				**363**	397	614
Foreign exchange (gain) loss, net				**(279)**	(210)	1,082
(Gain) loss on divestitures, net				**(404)**	(390)	(14)
Other (gains) losses, net				**(42)**	(58)	27
Total Other (Income) Expenses				**(362)**	(261)	1,709
Net Earnings (Loss) Before				**1,430**	(1,620)	(8,010)

Income Tax					
Income tax expense (recovery)		**603**		(676)	(2,845)
Net Earnings (Loss)		**$ 827**	$	(944)	$ (5,165)

Table of Contents

Intersegment Information

For the years ended December 31	Marketing Sales			Market Optimization Upstream Eliminations			Total		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Revenues	**$ 3,939**	$ 3,304	$ 4,309	**$ (3,076)**	$ (2,658)	$ (3,944)	**$ 863**	$ 646	$ 365
Operating Expenses									
Transportation and processing	**291**	279	348	**(188)**	(192)	(336)	**103**	87	12
Operating	**35**	35	33	**-**	-	-	**35**	35	33
Purchased product	**3,676**	3,052	3,931	**(2,888)**	(2,466)	(3,608)	**788**	586	323
Depreciation, depletion and amortization	**1**	-	-	**-**	-	-	**1**	-	-
Operating Income (Loss)	**$ (64)**	$ (62)	$ (3)	**$ -**	$ -	$ -	**$ (64)**	$ (62)	$ (3)

Capital Expenditures

For the years ended December 31	**2017**	2016	2015
Canadian Operations	**$ 426**	$ 256	$ 380
USA Operations	**1,358**	873	1,847
Market Optimization	**1**	1	1
Corporate & Other	**11**	2	4
	$ 1,796	$ 1,132	$ 2,232

Goodwill, Property, Plant and Equipment and Total Assets by Segment

As at December 31	Goodwill		Property, Plant and Equipment		Total Assets	
	2017	2016	**2017**	2016	**2017**	2016
Canadian Operations	**$ 696**	$ 650	**$ 862**	$ 602	**$ 1,908**	$ 1,542
USA Operations	**1,913**	2,129	**6,555**	6,050	**9,301**	9,535
Market Optimization	**-**	-	**2**	2	**152**	105
Corporate & Other	**-**	-	**1,535**	1,485	**3,906**	3,471
	$ 2,609	$ 2,779	**$ 8,954**	$ 8,139	**$ 15,267**	$ 14,653

Goodwill, Property, Plant and Equipment and Total Assets by Geographic Region

	Goodwill		Property, Plant and Equipment		Total Assets	
As at December 31	**2017**	2016	**2017**	2016	**2017**	2016
Canada	**$ 696**	$ 650	**$ 2,319**	$ 2,000	**$ 5,412**	$ 4,732
United States	**1,913**	2,129	**6,635**	6,139	**9,811**	9,902
Other Countries	**-**	-	**-**	-	**44**	19
	$ 2,609	$ 2,779	**$ 8,954**	$ 8,139	**$ 15,267**	$ 14,653

Export Sales

Sales of oil, NGLs and natural gas produced or purchased in Canada delivered to customers outside of Canada were $64 million for the year ended December 31, 2017 (2016 - $50 million; 2015 - $153 million).

Major Customers

In connection with the marketing and sale of Encana s own and purchased oil, NGLs and natural gas for the year ended December 31, 2017, the Company had two customers which individually accounted for more than 10 percent of Encana s product revenues. Sales to these customers, which have investment grade credit ratings, were approximately $709 million and $412 million which comprised $144 million in Canada and $977 million in the United States (2016 - two customers with sales of approximately $434 million and $343 million, respectively; 2015 - two customers with sales of approximately $447 million and $414 million, respectively).

Table of Contents

For the years ended December 31	2017	2016	2015
Acquisitions			
Canadian Operations	**$ 31**	$ 1	$ 9
USA Operations	**23**	209	27
Corporate & Other	**-**	-	34
Total Acquisitions	**54**	210	70
Divestitures			
Canadian Operations	**(41)**	(456)	(959)
USA Operations	**(695)**	(806)	(896)
Corporate & Other	**-**	-	(53)
Total Divestitures	**(736)**	(1,262)	(1,908)
Net Acquisitions & (Divestitures)	**$ (682)**	$ (1,052)	$ (1,838)

ACQUISITIONS

Acquisitions in 2017 in the Canadian and USA Operations primarily included land purchases with oil and liquids rich potential. Acquisitions in 2016 in the USA Operations primarily included the purchase of natural gas gathering and water handling assets in Piceance located in Colorado and the purchase of land and property in Eagle Ford with oil and liquids rich potential.

DIVESTITURES

In 2017, amounts received from the sale of assets were $736 million (2016 - $1,262 million; 2015 - $1,908 million). In 2017, divestitures were $41 million in the Canadian Operations and $695 million in the USA Operations.

Amounts received from the Company s divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools, except for divestitures that result in a significant alteration between capitalized costs and proved reserves in a country cost centre. For divestitures that result in a gain or loss and constitute a business, goodwill is allocated to the divestiture.

Canadian Operations

In 2017, divestitures in the Canadian Operations primarily included the sale of certain properties that did not complement Encana s existing portfolio of assets.

In 2016, divestitures in the Canadian Operations primarily included the sale of the Gordondale assets in Montney located in northwestern Alberta for proceeds of approximately C$600 million ($455 million), after closing adjustments. For the year ended December 31, 2016, Encana recognized a gain of approximately $394 million, before tax, on the sale of the Company s Gordondale assets in the Canadian cost centre and allocated goodwill of $32 million.

In 2015, divestitures in the Canadian Operations primarily included the sale of certain assets in Wheatland located in central and southern Alberta for proceeds of approximately C$557 million ($467 million), after closing adjustments, the sale of certain natural gas gathering and compression assets in Montney located in northeastern British Columbia for proceeds of approximately C$450 million ($355 million), after closing adjustments, and the sale of certain properties that did not complement Encana s existing portfolio of assets.

85

Table of Contents

USA Operations

In 2017, divestitures in the USA Operations primarily included the sale of the Piceance natural gas assets located in northwestern Colorado for proceeds of approximately $605 million, after closing and other adjustments, and the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana. For the year ended December 31, 2017, Encana recognized a gain of approximately $406 million, before tax, on the sale of the Company s Piceance assets in the U.S. cost centre and allocated goodwill of $216 million.

In 2016, divestitures in the USA Operations primarily included the sale of the DJ Basin assets located in northern Colorado for proceeds of approximately $633 million, after closing and other adjustments, as well as the sale of certain natural gas leasehold interests in Piceance located in Colorado for proceeds of approximately $135 million, after closing and other adjustments.

In 2015, divestitures in the USA Operations primarily included the sale of the Haynesville natural gas assets located in northern Louisiana for proceeds of approximately $769 million, after closing adjustments, and the sale of certain properties that did not complement Encana s existing portfolio of assets.

Corporate and Other

For the year ended December 31, 2015, Corporate and Other acquisitions and divestitures primarily included the purchase and subsequent sale of the Encana Place office building located in Calgary, which resulted in a gain on divestiture of approximately $12 million.

For the years ended December 31	**2017**	2016	2015
Interest Expense on:			
Debt	**$ 267**	$ 296	$ 497
The Bow office building	**63**	62	65
Capital leases	**20**	24	28
Other	**13**	15	24
	$ 363	$ 397	$ 614

Interest Expense on Debt for the year ended December 31, 2015 included a one-time interest payment of approximately $165 million resulting from the April 2015 early redemption of the Company s $700 million 5.90 percent notes due December 1, 2017 and C$750 million 5.80 percent medium-term notes due January 18, 2018 as discussed in Note 12.

Table of Contents

For the years ended December 31	**2017**	2016	2015
Unrealized Foreign Exchange (Gain) Loss on:			
Translation of U.S. dollar financing debt issued from Canada	**$ (243)**	$ (130)	$ 754
Translation of U.S. dollar risk management contracts issued from Canada	**(44)**	4	(67)
Translation of intercompany notes	**(4)**	(14)	-
	(291)	(140)	687
Foreign Exchange on Settlements of:			
U.S. dollar financing debt issued from Canada	**14**	(73)	269
U.S. dollar risk management contracts issued from Canada	**(15)**	-	-
Intercompany notes	**10**	5	89
Other Monetary Revaluations	**3**	(2)	37
	$ (279)	$ (210)	$ 1,082

The unrealized foreign exchange (gain) loss on translation of U.S. dollar financing debt issued from Canada for the year ended December 31, 2017 disclosed in the table above includes an out-of-period adjustment in respect of unrealized losses on a foreign-denominated capital lease obligation since December 2013. The cumulative impact recognized within foreign exchange (gain) loss in the Company s Consolidated Statement of Earnings for the year ended December 31, 2017 was $68 million, before tax ($47 million, after tax). Encana has determined that the adjustment is not material to the Consolidated Financial Statements for the year ended December 31, 2017 or any prior periods. Accordingly, comparative periods presented in the Consolidated Financial Statements have not been restated.

The provision for income taxes is as follows:

For the years ended December 31	**2017**	2016	2015
Current Tax			
Canada	**$ (59)**	$ (82)	$ (25)
United States	**(9)**	-	(17)
Other Countries	**5**	4	8
Total Current Tax Expense (Recovery)	**(63)**	(78)	(34)
Deferred Tax			

Canada	**55**	(163)	(316)
United States	**611**	(435)	(2,495)
Other Countries	**-**	-	-
Total Deferred Tax Expense (Recovery)	**666**	(598)	(2,811)
Income Tax Expense (Recovery)	**$ 603**	$ (676)	$ (2,845)

During the year ended December 31, 2017, the current tax recovery was primarily due to the successful resolution of certain tax items previously assessed by the taxing authorities relating to prior taxation years. During the years ended December 31, 2016 and December 31, 2015, the current tax recoveries were primarily due to amounts recorded in respect of prior periods.

On December 22, 2017, the Tax Cuts and Jobs Act (U.S. Tax Reform) was signed into law making significant changes to the U.S. tax code, including a reduction of the U.S. federal corporate tax rate from 35 percent to 21 percent. During the year ended December 31, 2017, the deferred tax expense of $666 million includes a provisional adjustment of $327 million resulting from the re-measurement of the Company s tax position due to U.S. Tax Reform. The adjustment of $327 million includes a $26 million valuation allowance re-measurement with respect to U.S. foreign tax credits and U.S. charitable donations.

The SEC Staff Accounting Bulletin No. 118 addresses the application of U.S. GAAP in situations when a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the

Table of Contents

accounting for certain income tax effects of U.S. Tax Reform. The ultimate impact of U.S. Tax Reform may differ from the provisional amount recognized of $327 million due to additional analysis, changes in interpretations and assumptions made by the Company, additional regulatory guidance that may be issued, and actions the Company may take as a result of U.S. Tax Reform. Any subsequent adjustments to the provisional amount will be recorded in income tax expense in the period in which the analysis is complete.

U.S. Tax Reform also included new rules to limit the deductibility for related party interest amounts. As at December 31, 2017, the Company has a carryforward balance of deferred interest deductions for which a deferred income tax asset of $28 million has been recorded. It is unclear whether the new rules would limit the realizability of this carryforward interest amount. Further clarification is required of the transition rules through potential Treasury Department regulations and guidance before a final determination can be made.

During the years ended December 31, 2016 and December 31, 2015, the deferred tax recoveries were primarily due to the ceiling test impairments recognized in the Canadian and USA Operations as disclosed in Note 8.

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

For the years ended December 31	**2017**	2016	2015
Net Earnings (Loss) Before Income Tax			
Canada	**$ 512**	$ (627)	$ (2,014)
United States	**476**	(1,522)	(6,963)
Other Countries	**442**	529	967
Total Net Earnings (Loss) Before Income Tax	**1,430**	(1,620)	(8,010)
Canadian Statutory Rate	**27.0%**	27.0%	26.4%
Expected Income Tax	**386**	(437)	(2,115)
Effect on Taxes Resulting From:			
Income tax related to foreign operations	**(73)**	(266)	(776)
Effect of legislative changes	**299**	-	(11)
Non-taxable capital (gains) losses	**(39)**	(29)	132
Tax differences on divestitures and transactions	**77**	9	(8)
Partnership tax allocations in excess of funding	**(54)**	(17)	(21)
Amounts in respect of prior periods	**(49)**	(11)	(8)
Change in valuation allowance	**54**	121	-
Other	**2**	(46)	(38)
	$ 603	$ (676)	$ (2,845)
Effective Tax Rate	**42.2%**	41.7%	35.5%

For the year ended December 31, 2017, the effective tax rate was 42.2 percent, which is higher than the Canadian statutory tax rate of 27 percent primarily due to U.S. Tax Reform, which increased Encana s effective tax rate by

22.9 percent. The effective tax rate for the years ended December 31, 2016 and December 31, 2015 exceeded the Canadian statutory tax rate of 27 percent and 26.4 percent, respectively, primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings.

Table of Contents

The net deferred income tax asset (liability) consists of:

As at December 31	2017	2016
Deferred Income Tax Assets		
Property, plant and equipment	**$ 281**	$ 256
Risk management	**34**	81
Compensation plans	**99**	100
Interest and other deferred deductions	**28**	48
Unrealized foreign exchange losses	**-**	20
Non-capital and net capital losses carried forward	**1,014**	1,149
Foreign tax credits	**198**	198
Other	**53**	82
Less: valuation allowance	**(187)**	(133)
Deferred Income Tax Liabilities		
Property, plant and equipment	**(386)**	(155)
Risk management	**(97)**	-
Unrealized foreign exchange gains	**(18)**	-
Other	**(10)**	(19)
Net Deferred Income Tax Asset (Liability)	**$ 1,009**	$ 1,627

As at December 31, 2017, Encana has recorded a valuation allowance against U.S. foreign tax credits and U.S. charitable donations in the amounts of $156 million (2016 - $129 million) and $3 million (2016 - $4 million), respectively, as it is more likely than not that these benefits will not be realized based on expected future taxable earnings as determined in accordance with the Company s accounting policies. This change in the valuation allowance of $26 million arose from the re-measurement due to U.S. Tax Reform as noted above. In addition, a valuation allowance of $28 million (2016 - nil) was taken against U.S. state losses as it is more likely than not that these benefits will not be realized based on expected future taxable state earnings.

The net deferred income tax asset (liability) for the following jurisdictions is reflected in the Consolidated Balance Sheet as follows:

As at December 31	2017	2016
Deferred Income Tax Assets		
Canada	**$ 555**	$ 568
United States	**488**	1,090
	1,043	1,658
Deferred Income Tax Liabilities		

Canada	**(34)**	(31)
United States	**-**	-
	(34)	(31)
Net Deferred Income Tax Asset (Liability)	**$ 1,009**	$ 1,627

Table of Contents

Tax pools, loss carryforwards, charitable donations and tax credits available are as follows:

As at December 31	2017	Expiration Date
Canada		
Tax pools	$ 1,520	Indefinite
Net capital losses	15	Indefinite
Non-capital losses	982	2027 - 2037
Charitable donations	1	2022
United States		
Tax basis	$ 4,703	Indefinite
Non-capital losses (Federal)	3,407	2031 - 2037
Charitable donations	13	2019 - 2023
Foreign tax credits	198	2021 - 2025

As at December 31, 2017, approximately $3.2 billion of Encana s unremitted earnings from its foreign subsidiaries were considered to be permanently reinvested outside of Canada and, accordingly, Encana has not recognized a deferred income tax liability for Canadian income taxes in respect of such earnings. If such earnings were to be remitted to Canada, Encana may be subject to Canadian income taxes and foreign withholding taxes. However, determination of any potential amount of unrecognized deferred income tax liabilities is not practicable.

The following table presents changes in the balance of Encana s unrecognized tax benefits excluding interest:

For the years ended December 31	2017	2016
Balance, Beginning of Year	$ (286)	$ (317)
Additions for tax positions taken in the current year	-	-
Additions for tax positions of prior years	(1)	(1)
Reductions for tax positions of prior years	1	-
Lapse of statute of limitations	-	42
Settlements	-	-
Foreign currency translation	(20)	(10)
Balance, End of Year	$ (306)	$ (286)

The unrecognized tax benefit is reflected in the Consolidated Balance Sheet as follows:

For the years ended December 31	2017	2016
Income tax receivable	$ (45)	$ (21)

Other liabilities and provisions (See Note 13)	**(202)**		(193)
Deferred income tax asset	**(59)**		(72)
Balance, End of Year	**$ (306)**	$	(286)

If recognized, all of Encana s unrecognized tax benefits as at December 31, 2017 would affect Encana s effective income tax rate. Encana does not anticipate that the amount of unrecognized tax benefits will significantly change during the next 12 months.

Encana recognizes interest accrued in respect of unrecognized tax benefits in interest expense. During 2017, Encana recognized $12 million (2016 - $1 million; 2015 - $2 million) in interest expense. As at December 31, 2017, Encana had a liability of $16 million (2016 - $4 million) for interest accrued in respect of unrecognized tax benefits.

Table of Contents

Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by the taxing authorities.

Jurisdiction	Taxation Year
Canada - Federal	**2009 - 2017**
Canada - Provincial	**2009 - 2017**
United States - Federal	**2014 - 2017**
United States - State	**2013 - 2017**
Other	**2016 - 2017**

Encana and its subsidiaries file income tax returns primarily in Canada and the United States. Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion.

As at December 31	2017	2016
Trade Receivables and Accrued Revenues		
Oil, NGLs and natural gas	**$ 425**	$ 394
Midstream and marketing	**284**	161
Derivative financial instruments	**3**	4
Corporate and other	**9**	81
Total Trade Receivables and Accrued Revenues	**721**	640
Prepaids	**21**	18
Deposits and Other	**37**	11
	779	669
Allowance for Doubtful Accounts	**(5)**	(6)
	$ 774	$ 663

Encana s trade receivables balance primarily consists of oil, NGLs and natural gas sales receivables, marketing revenues and joint interest receivables. Trade receivables are non-interest bearing. In determining the recoverability of trade receivables, the Company considers the age of the outstanding receivable and the credit worthiness of the counterparties. The Company charges uncollectible trade receivables to the allowance for doubtful accounts when it is determined no longer collectible. See Note 22 for further information about credit risk.

Table of Contents

As at December 31	2017 Cost	2017 Accumulated DD&A	2017 Net	2016 Cost	2016 Accumulated DD&A	2016 Net
Canadian Operations						
Proved properties	**$ 14,555**	**$ (14,047)**	**$ 508**	$ 13,159	$ (12,896)	$ 263
Unproved properties	**311**	**-**	**311**	285	-	285
Other	**43**	**-**	**43**	54	-	54
	14,909	**(14,047)**	**862**	13,498	(12,896)	602
USA Operations						
Proved properties	**25,610**	**(23,240)**	**2,370**	26,393	(25,300)	1,093
Unproved properties	**4,169**	**-**	**4,169**	4,913	-	4,913
Other	**16**	**-**	**16**	44	-	44
	29,795	**(23,240)**	**6,555**	31,350	(25,300)	6,050
Market Optimization	**7**	**(5)**	**2**	6	(4)	2
Corporate & Other	**2,299**	**(764)**	**1,535**	2,148	(663)	1,485
	$ 47,010	**$ (38,056)**	**$ 8,954**	$ 47,002	$ (38,863)	$ 8,139

Canadian and USA Operations property, plant and equipment include internal costs directly related to exploration, development and construction activities of $208 million, which have been capitalized during the year ended December 31, 2017 (2016 - $161 million). Included in Corporate and Other are $63 million (2016 - $58 million) of international property costs, which have been fully impaired.

For the year ended December 31, 2017, the Company did not recognize any ceiling test impairments in the Canadian or U.S. cost centres. For the year ended December 31, 2016, the Company recognized before-tax ceiling test impairments of $493 million (2015 - nil) in the Canadian cost centre and $903 million (2015 - $6,473 million) in the U.S. cost centre. The impairments recognized in 2016 are included with accumulated DD&A in the table above and resulted primarily from the decline in the 12-month average trailing prices which reduced proved reserves volumes and values.

The 12-month average trailing prices used in the ceiling test calculations reflect benchmark prices adjusted for basis differentials to determine local reference prices, transportation costs and tariffs, heat content and quality. The benchmark prices are disclosed in Note 25.

Capital Lease Arrangements

The Company has several lease arrangements that are accounted for as capital leases including an office building and an offshore production platform.

As at December 31, 2017, the total carrying value of assets under capital lease was $46 million (2016 - $51 million), net of accumulated amortization of $684 million (2016 - $648 million). Liabilities for the capital lease arrangements are included in other liabilities and provisions in the Consolidated Balance Sheet and are disclosed in Note 13.

Other Arrangement

As at December 31, 2017, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,255 million (2016 - $1,194 million) related to The Bow office building, which is under a 25-year lease agreement. The Bow asset is being depreciated over the 60-year estimated life of the building. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 13.

Table of Contents

As at December 31	2017	2016
Long-Term Investments	$ 26	$ 26
Long-Term Receivables	72	71
Deferred Charges	7	9
Other [1]	39	32
	$ 144	$ 138

(1) Includes $2 million previously reported as Cash in Reserve in the 2016 Consolidated Balance Sheet.

As at December 31	2017	2016
Canada		
Balance, Beginning of Year	$ 650	$ 661
Divested During the Year (See Note 3)	-	(32)
Foreign Currency Translation Adjustment	46	21
Balance, End of Year	696	650
United States		
Balance, Beginning of Year	2,129	2,129
Divested During the Year (See Note 3)	(216)	-
Balance, End of Year	1,913	2,129
Total Goodwill	$ 2,609	$ 2,779

During 2017, the Company derecognized goodwill of $216 million upon the divestiture of the Piceance assets as described in Note 3. During 2016, the Company derecognized goodwill of $32 million upon the divestiture of the Gordondale assets as described in Note 3.

Goodwill was assessed for impairment as at December 31, 2017 and December 31, 2016. The fair values of the Canada and United States reporting units were determined to be greater than the respective carrying values of the reporting units. Accordingly, no goodwill impairments were recognized. The Company has not recognized any historical cumulative goodwill impairments.

As at December 31	2017	2016
Trade Payables	$ 258	$ 240
Capital Accruals	319	280
Royalty and Production Accruals	278	300
Other Accruals	216	234
Interest Payable	69	69
Current Portion of Long-Term Incentive Costs (See Note 19)	152	88
Current Portion of Capital Lease Obligations (See Note 13)	79	59
Current Portion of Asset Retirement Obligation (See Note 14)	44	33
	$ 1,415	$ 1,303

Payables and accruals are non-interest bearing. Interest payable represents amounts accrued related to Encana s unsecured notes as disclosed in Note 12.

Table of Contents

As at December 31	*Note*	**2017**	2016
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	*A*	**$ -**	$ -
U.S. Unsecured Notes:	*B*		
6.50% due May 15, 2019		**500**	500
3.90% due November 15, 2021		**600**	600
8.125% due September 15, 2030		**300**	300
7.20% due November 1, 2031		**350**	350
7.375% due November 1, 2031		**500**	500
6.50% due August 15, 2034		**750**	750
6.625% due August 15, 2037 (1)		**462**	462
6.50% due February 1, 2038 (1)		**505**	505
5.15% due November 15, 2041 (1)		**244**	244
Total Principal	*F*	**4,211**	4,211
Increase in Value of Debt Acquired	*C*	**26**	26
Unamortized Debt Discounts and Issuance Costs	*D*	**(40)**	(39)
Current Portion of Long-Term Debt	*E*	**-**	-
		$ 4,197	$ 4,198

(1) Notes accepted for purchase in the March 2016 Tender Offers.

A) REVOLVING CREDIT AND TERM LOAN BORROWINGS

At December 31, 2017, Encana had in place committed revolving U.S. dollar denominated bank credit facilities totaling $4.5 billion which included $3.0 billion on a revolving bank credit facility for Encana and $1.5 billion on a revolving bank credit facility for a U.S. subsidiary. The facilities are extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from Encana. The facilities mature in July 2020, and are fully revolving up to maturity.

Encana is subject to a financial covenant in its credit facility agreements whereby financing debt to adjusted capitalization cannot exceed 60 percent. Financing debt primarily includes total long-term debt and capital lease obligations. Adjusted capitalization is calculated as the sum of total financing debt, shareholders equity and a $7.7 billion equity adjustment for cumulative historical ceiling test impairments recorded as at December 31, 2011 in conjunction with the Company s January 1, 2012 adoption of U.S. GAAP. As at December 31, 2017, the Company is in compliance with all financial covenants.

The Encana facility, which remained unused at December 31, 2017, is unsecured and bears interest at the lenders rates for Canadian prime, U.S. base rate, Bankers Acceptances or LIBOR, plus applicable margins. The U.S. subsidiary

facility, which remained unused as at December 31, 2017, bears interest at either the lenders U.S. base rate or LIBOR, plus applicable margins.

Standby fees paid in 2017 relating to revolving credit and term loan agreements were approximately $15 million (2016 - $14 million; 2015 - $11 million).

B) UNSECURED NOTES

Shelf Prospectuses

Encana filed a shelf prospectus in Canada and a shelf registration statement in the U.S., in 2016 and 2017, respectively, whereby the Company may issue from time to time, debt securities, common shares, Class A preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units in Canada and/or the U.S. In September 2016 and March 2015, the Company filed prospectus supplements for the issuance of common shares as described in Note 15. At

Table of Contents

December 31, 2017, $4.8 billion remained accessible under the Canadian shelf prospectus. The availability of issuing securities under the Canadian shelf prospectus and U.S. shelf registration statement is dependent upon market conditions.

U.S. Unsecured Notes

Unsecured notes include medium-term notes and senior notes that are issued from time to time under trust indentures and have equal priority with respect to the payment of both principal and interest.

On March 16, 2016, Encana announced tender offers (collectively, the Tender Offers) for certain of the Company s outstanding senior notes (collectively, the Notes). The Tender Offers were for an aggregate purchase price of $250 million, excluding accrued and unpaid interest. The consideration for each $1,000 principal amount of Notes validly tendered and accepted for purchase included an early tender premium of $30 per $1,000 principal amount of Notes accepted for purchase, provided the Notes were validly tendered at or prior to the early tender date of March 29, 2016. All Notes validly tendered and accepted for purchase also received accrued and unpaid interest up to the settlement date.

On March 30, 2016, Encana announced an increase in the aggregate purchase price of the Tender Offers to $400 million, excluding accrued and unpaid interest, and accepted for purchase: i) $156 million aggregate principal amount of 5.15 percent notes due 2041; ii) $295 million aggregate principal amount of 6.50 percent notes due 2038; and iii) $38 million aggregate principal amount of 6.625 percent notes due 2037. The Company paid an aggregate amount of $406 million, including accrued and unpaid interest of $6 million and an early tender premium of $14 million, for Notes accepted for purchase. The Company used cash on hand and borrowings under its revolving credit facility to fund the Tender Offers.

Encana also recognized a gain on the early debt retirement of $103 million, before tax, representing the difference between the carrying amount of the Notes accepted for purchase and the consideration paid. The gain on the early debt retirement net of the early tender premium totaled $89 million, which is included in other (gains) losses in the Consolidated Statement of Earnings.

On March 5, 2015, Encana provided notice to noteholders that it would redeem the Company s $700 million 5.90 percent notes due December 1, 2017 and C$750 million 5.80 percent medium-term notes due January 18, 2018. On April 6, 2015, the Company used net proceeds from the common shares issued, as disclosed in Note 15, and cash on hand to complete the note redemptions. In conjunction with the early note redemptions, the Company incurred a one-time interest payment of approximately $165 million as discussed in Note 4.

C) INCREASE IN VALUE OF DEBT ACQUIRED

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, which is approximately 13 years.

D) UNAMORTIZED DEBT DISCOUNTS AND ISSUANCE COSTS

Long-term debt premiums and discounts are capitalized within long-term debt and are being amortized using the effective interest method. During 2017 and 2016, no debt premiums or discounts were capitalized. Issuance costs are

amortized over the term of the related debt.

E) CURRENT PORTION OF LONG-TERM DEBT

As at December 31, 2017 and 2016, there was no current portion of long-term debt.

Table of Contents

F) MANDATORY DEBT PAYMENTS

As at December 31	Principal Amount	Interest Amount
2018	**$ -**	**$ 267**
2019	**500**	**251**
2020	**-**	**234**
2021	**600**	**235**
2022	**-**	**211**
Thereafter	**3,111**	**2,546**
Total	**$ 4,211**	**$ 3,744**

As at December 31, 2017, total long-term debt had a carrying value of $4,197 million and a fair value of $5,042 million (2016 - carrying value of $4,198 million and a fair value of $4,553 million). The estimated fair value of long-term borrowings is categorized within Level 2 of the fair value hierarchy and has been determined based on market information of long-term debt with similar terms and maturity, or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

As at December 31	2017	2016
The Bow Office Building	**$ 1,344**	$ 1,266
Capital Lease Obligations	**295**	304
Unrecognized Tax Benefits (See Note 6)	**202**	193
Pensions and Other Post-Employment Benefits	**116**	124
Long-Term Incentive Costs (See Note 19)	**175**	120
Other Derivative Contracts (See Notes 21, 22)	**14**	14
Other	**21**	26
	$ 2,167	$ 2,047

The Bow Office Building

As described in Note 8, Encana has recognized the accumulated costs for The Bow office building, which is under a 25-year lease agreement. At the conclusion of the lease term, the remaining asset and corresponding liability are expected to be derecognized. Encana has also subleased approximately 50 percent of The Bow office space under the lease agreement. The total expected future principal and interest payments related to the 25-year lease agreement and the total undiscounted future amounts expected to be recovered from the sublease are outlined below.

	2018	2019	2020	2021	2022	Thereafter	Total
Expected Future Lease Payments	$ 76	$ 77	$ 77	$ 78	$ 78	$ 1,295	**$ 1,681**
Less: Amounts Representing Interest	65	65	63	63	62	802	**1,120**
Present Value of Expected Future							
Lease Payments	$ 11	$ 12	$ 14	$ 15	$ 16	$ 493	**$ 561**
Sublease Recoveries (undiscounted)	$ (37)	$ (38)	$ (38)	$ (38)	$ (39)	$ (636)	**$ (826)**

Capital Lease Obligations

As described in Note 8, the Company has several lease arrangements that are accounted for as capital leases including an office building and the Deep Panuke offshore Production Field Centre (PFC). Variable interests related to the PFC are described in Note 17.

Table of Contents

The total expected future lease payments related to the Company s capital lease obligations are outlined below.

	2018	2019	2020	2021	2022	Thereafter	Total
Expected Future Lease Payments	$ 99	$ 99	$ 99	$ 87	$ 8	$ 38	**$ 430**
Less: Amounts Representing Interest	20	15	10	4	2	5	**56**
Present Value of Expected Future Lease Payments	$ 79	$ 84	$ 89	$ 83	$ 6	$ 33	**$ 374**

As at December 31	2017	2016
Asset Retirement Obligation, Beginning of Year	**$ 687**	$ 814
Liabilities Incurred and Acquired	**11**	18
Liabilities Settled and Divested	**(333)**	(107)
Change in Estimated Future Cash Outflows	**88**	(99)
Accretion Expense	**37**	51
Foreign Currency Translation	**24**	10
Asset Retirement Obligation, End of Year	**$ 514**	$ 687
Current Portion (See Note 11)	**$ 44**	$ 33
Long-Term Portion	**470**	654
	$ 514	$ 687

AUTHORIZED

The Company is authorized to issue an unlimited number of no par value common shares and Class A Preferred Shares limited to a number equal to not more than 20 percent of the issued and outstanding number of common shares at the time of issuance. No Class A Preferred Shares are outstanding.

ISSUED AND OUTSTANDING

As at December 31	**2017**		2016		2015	
	Number (millions)	**Amount**	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**973.0**	**$ 4,756**	849.8	$ 3,621	741.2	$ 2,450
Common Shares Issued	**-**	**-**	123.1	1,134	98.4	1,098
Common Shares Issued Under Dividend Reinvestment Plan	**0.1**	**1**	0.1	1	10.2	73
Common Shares Outstanding, End of Year	**973.1**	**$ 4,757**	973.0	$ 4,756	849.8	$ 3,621

On September 19, 2016, Encana filed prospectus supplements (the 2016 Share Offering) to the Company s shelf prospectuses for the issuance of 107,000,000 common shares and granted an over-allotment option for up to an additional 16,050,000 common shares at a price of $9.35 per common share, pursuant to an underwriting agreement. The aggregate gross proceeds from the 2016 Share Offering, including the exercise in full of the over-allotment option, were approximately $1.15 billion. After deducting underwriters fees and costs of the 2016 Share Offering, the net cash proceeds received were approximately $1.13 billion.

On March 5, 2015, Encana filed a prospectus supplement (the 2015 Share Offering) to the Company s shelf prospectus for the issuance of 85,616,500 common shares and granted an over-allotment option for up to an additional 12,842,475 common shares at a price of C$14.60 per common share, pursuant to an underwriting agreement. The aggregate gross proceeds from the 2015 Share Offering, including the exercise in full of the over-allotment option, were approximately C$1.44 billion

Table of Contents

($1.13 billion). After deducting underwriters fees and costs of the 2015 Share Offering, the net cash proceeds received were approximately C$1.39 billion ($1.09 billion).

During the year ended December 31, 2017, Encana issued 58,480 common shares totaling $0.6 million under the Company s dividend reinvestment plan (DRIP) (2016 - issued 121,249 common shares totaling $0.9 million; 2015 - issued 10,246,221 common shares totaling $73 million).

On February 15, 2018, the Company announced plans to spend up to $400 million to purchase, for cancellation, up to 35 million common shares through a NCIB, subject to and following TSX approval. On February 26, 2018, the Company announced that the TSX accepted its notice of intention to commence the NCIB beginning February 28, 2018 and ending February 27, 2019.

DIVIDENDS

For the year ended December 31, 2017, Encana paid dividends of $0.06 per common share totaling $58 million (2016 - $0.06 per common share totaling $52 million; 2015 - $0.28 per common share totaling $225 million). The Company s quarterly dividend payment in 2017 and 2016 was $0.015 per common share. The Company s quarterly dividend payment in 2015 was $0.07 per common share. Common shares issued as part of the 2016 Share Offering and 2015 Share Offering described above were not eligible to receive the dividends paid on September 30, 2016 and March 31, 2015, respectively.

For the year ended December 31, 2017, the dividends paid included $0.6 million in common shares as disclosed above, which were issued in lieu of cash dividends under the DRIP (2016 - $0.9 million; 2015 - $73 million).

On February 14, 2018, the Board of Directors declared a dividend of $0.015 per common share payable on March 29, 2018 to common shareholders of record as of March 15, 2018.

EARNINGS PER COMMON SHARE

The following table presents the computation of net earnings (loss) per common share:

For the years ended December 31 (US$ millions, except per share amounts)	**2017**	2016	2015
Net Earnings (Loss)	**$ 827**	$ (944)	$ (5,165)
Number of Common Shares:			
Weighted average common shares outstanding - Basic	**973.1**	882.6	822.1
Effect of dilutive securities	**-**	-	-
Weighted average common shares outstanding - Diluted	**973.1**	882.6	822.1
Net Earnings (Loss) per Common Share			
Basic & Diluted	**$ 0.85**	$ (1.07)	$ (6.28)

ENCANA STOCK OPTION PLAN

Encana has share-based compensation plans that allow employees to purchase common shares of the Company. Option exercise prices are not less than the market value of the common shares on the date the options are granted. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. Options granted after February 2015 expire seven years after the date granted.

All options outstanding as at December 31, 2017 have associated Tandem Stock Appreciation Rights (TSARs) attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana s common shares at the time of the exercise over the original grant price. In addition, certain stock options granted are performance-based. The Performance TSARs vest and expire under the same terms and conditions as the underlying option. Vesting is also subject to Encana attaining prescribed performance relative to predetermined key measures. Historically, most holders of options with TSARs have elected to exercise their stock options as a Stock Appreciation Right (SAR) in exchange for a cash payment. As a result, outstanding TSARs are not considered potentially dilutive securities. See Note 19 for further information on Encana s outstanding and exercisable TSARs and Performance TSARs.

At December 31, 2017, there were 33.3 million common shares reserved for issuance under stock option plans (2016 - 32.2 million; 2015 - 30.3 million).

Table of Contents

ENCANA RESTRICTED SHARE UNITS (RSUs)

Encana has a share-based compensation plan whereby eligible employees are granted RSUs. An RSU is a conditional grant to receive the equivalent of an Encana common share upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. RSUs vest three years from the date granted, provided the employee remains actively employed with Encana on the vesting date. The Company intends to settle vested RSUs in cash on the vesting date. As a result, RSUs are not considered potentially dilutive securities. See Note 19 for further information on Encana s outstanding RSUs.

For the years ended December 31	2017	2016	2015
Foreign Currency Translation Adjustment			
Balance, Beginning of Year	**$ 1,200**	$ 1,383	$ 715
Change in Foreign Currency Translation Adjustment	**(171)**	(183)	668
Balance, End of Year	**$ 1,029**	$ 1,200	$ 1,383
Pension and Other Post-Employment Benefit Plans			
Balance, Beginning of Year	**$ 10**	$ 7	$ (26)
Net Actuarial Gains and (Losses) (See Note 20)	**7**	6	46
Income Taxes	**(2)**	(2)	(15)
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 20)	**-**	(1)	2
Income Taxes	**-**	-	-
Reclassification of Net Prior Service Costs to Net Earnings (See Note 20)	**(1)**	-	-
Income Taxes	**-**	-	-
Curtailment in Net Defined Periodic Benefit Cost (See Note 20)	**(1)**	-	-
Income Taxes	**-**	-	-
Balance, End of Year	**$ 13**	$ 10	$ 7
Total Accumulated Other Comprehensive Income	**$ 1,042**	$ 1,210	$ 1,390

Production Field Centre

In 2008, Encana entered into a contract for the design, construction and operation of the PFC at its Deep Panuke facility. Upon commencement of operations in December 2013, Encana recognized the PFC as a capital lease asset.

Under the lease contract, Encana has a purchase option and the option to extend the lease for 12 one-year terms at fixed prices after the initial lease term expires in 2021.

As a result of the purchase option and fixed price renewal options, Encana has determined it holds variable interests and that the related leasing entity qualifies as a variable interest entity (VIE). Encana is not the primary beneficiary of the VIE as the Company does not have the power to direct the activities that most significantly impact the VIE s economic performance. Encana is not required to provide any financial support or guarantees to the leasing entity or its affiliates, other than the contractual payments under the lease and operating agreements. Encana s maximum exposure is the expected lease payments over the initial contract term. As at December 31, 2017, Encana had a capital lease obligation of $314 million (2016 - $299 million) related to the PFC.

Table of Contents

Veresen Midstream Limited Partnership

Veresen Midstream Limited Partnership (VMLP) provides gathering, compression and processing services under various agreements related to the Company s development of liquids and natural gas production in the Montney play. As at December 31, 2017, VMLP provides approximately 630 MMcf/d of natural gas gathering and compression and 772 MMcf/d of natural gas processing under long-term service agreements with remaining terms ranging from up to 15 to 28 years and have various renewal terms providing up to a potential maximum of 10 years.

Encana has determined that VMLP is a VIE and that Encana holds variable interests in VMLP. Encana is not the primary beneficiary as the Company does not have the power to direct the activities that most significantly impact VMLP s economic performance. These key activities relate to the construction, operation, maintenance and marketing of the assets owned by VMLP. The variable interests arise from certain terms under the various long-term service agreements and include: i) a take or pay for volumes in certain agreements; ii) an operating fee of which a portion can be converted into a fixed fee once VMLP assumes operatorship of certain assets; and iii) a potential payout of minimum costs in certain agreements. The potential payout of minimum costs will be assessed in the eighth year of the assets service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain agreements. The potential payout amount can be reduced in the event VMLP markets unutilized capacity to third party users. Encana is not required to provide any financial support or guarantees to VMLP.

As a result of Encana s involvement with VMLP, the maximum total exposure, which represents the potential exposure to Encana in the event the assets under the agreements are deemed worthless, is estimated to be $2,344 million as at December 31, 2017. The estimate comprises the take or pay volume commitments and the potential payout of minimum costs. The take or pay volume commitments associated with certain gathering and processing assets are included in Note 24 under Transportation and Processing. The potential payout requirement is highly uncertain as the amount is contingent on future production estimates, pace of development and the amount of capacity contracted to third parties. As at December 31, 2017, there were no accounts payable and accrued liabilities outstanding related to the take or pay commitment.

In 2013 and 2015, Encana recognized employee and other related costs associated with workforce reductions as a result of organizational restructurings to support changes in the Company s strategy. During 2015, transition and severance costs of $64 million, before tax, were incurred, of which $2 million related to the 2013 restructuring plan. As at December 31, 2015, $13 million remained accrued.

In February 2016, Encana announced workforce reductions to better align staffing levels and the organizational structure with the Company s reduced capital spending program as a result of the low commodity price environment. During 2016, the Company incurred total restructuring charges of $34 million, before tax, primarily related to severance costs, of which $7 million remained accrued as at December 31, 2016. As at December 31, 2017, all restructuring costs have been paid.

Restructuring charges are included in administrative expense presented in the Corporate & Other segment in the Consolidated Statement of Earnings.

For the years ended December 31	**2017**	2016	2015
Employee Severance and Benefits	**$ -**	$ 33	$ 58
Consultants and Building Sublease Brokerage Fees	**-**	-	4
Outplacement, Moving and Other Expenses	**-**	1	2
	$ -	$ 34	$ 64

Table of Contents

For the years ended December 31	2017	2016	2015
Outstanding Restructuring Accrual, Beginning of Year	$ 7	$ 13	$ 4
Current Year Restructuring Expenses Incurred	-	34	62
Charges Related to Prior Years Restructuring	-	-	2
Restructuring Costs Paid	(7)	(40)	(55)
Outstanding Restructuring Accrual, End of Year [1]	$ -	$ 7	$ 13

(1) Included in accounts payable and accrued liabilities in the Consolidated Balance Sheet.

Encana has a number of compensation arrangements under which the Company awards various types of long-term incentive grants to eligible employees. They include TSARs, Performance TSARs, SARs, Performance Share Units (PSUs), Deferred Share Units (DSUs) and RSUs. These compensation arrangements are share-based.

Encana accounts for TSARs, Performance TSARs, SARs, PSUs, and RSUs held by employees as cash-settled share-based payment transactions and, accordingly, accrues compensation costs over the vesting period based on the fair value of the rights determined using the Black-Scholes-Merton and other fair value models. TSARs and SARs granted vest and are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. TSARs and SARs granted after February 2015 expire seven years after the date granted. Performance TSARs vest over a four-year period based on prescribed performance targets and expire if not eligible to vest after that time. PSUs and RSUs vest three years from the date of grant, provided the employee remains actively employed with Encana on the vesting date.

The following weighted average assumptions were used to determine the fair value of the share units held by employees:

	US$ Share Units		
As at December 31	2017	2016	2015
Risk Free Interest Rate	1.67%	0.75%	0.48%
Dividend Yield	0.45%	0.51%	1.18%
Expected Volatility Rate [1]	57.87%	57.18%	39.16%
Expected Term	1.4 yrs	1.9 yrs	1.4 yrs
Market Share Price	US$13.33	US$11.74	US$5.09

C$ Share Units

As at December 31	**2017**	2016	2015
Risk Free Interest Rate	**1.67%**	0.75%	0.48%
Dividend Yield	**0.46%**	0.50%	1.09%
Expected Volatility Rate [1]	**54.10%**	53.24%	36.45%
Expected Term	**1.5 yrs**	1.9 yrs	1.5 yrs
Market Share Price	**C$16.77**	C$15.76	C$7.03

(1) Volatility was estimated using historical rates.

Table of Contents

The Company has recognized the following share-based compensation costs:

For the years ended December 31	2017	2016	2015
Total Compensation Costs of Transactions Classified as Cash-Settled	$ 165	$ 174	$ (29)
Less: Total Share-Based Compensation Costs Capitalized	(55)	(40)	10
Total Share-Based Compensation Expense (Recovery)	$ 110	$ 134	$ (19)
Recognized on the Consolidated Statement of Earnings in:			
Operating	$ 34	$ 48	$ (7)
Administrative	76	86	(12)
	$ 110	$ 134	$ (19)

As at December 31, 2017, the liability for share-based payment transactions totaled $327 million (2016 - $208 million), of which $152 million (2016 - $88 million) is recognized in accounts payable and accrued liabilities and $175 million (2016 - $120 million) is recognized in other liabilities and provisions in the Consolidated Balance Sheet.

For the years ended December 31	2017	2016	2015
Liability for Cash-Settled Share-Based Payment Transactions:			
Unvested	$ 274	$ 171	$ 47
Vested	53	37	4
	$ 327	$ 208	$ 51

The following sections outline certain information related to Encana s compensation plans as at December 31, 2017.

A) TANDEM STOCK APPRECIATION RIGHTS

All options to purchase common shares issued under the Encana Stock Option Plan have associated TSARs attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana s common shares at the time of exercise over the original grant price. The TSARs vest and expire under the same terms and conditions as the underlying option.

The following tables summarize information related to the TSARs held by employees:

As at December 31	2017	2016

(thousands of units)	**Outstanding TSARs**	**Weighted Average Exercise Price (C$)**	Outstanding TSARs	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	**15,482**	**14.92**	17,369	20.21
Granted	**850**	**15.43**	4,277	5.56
Exercised - SARs	**(316)**	**5.56**	-	-
Exercised - Options	**-**	**-**	-	-
Forfeited	**(218)**	**19.55**	(2,108)	19.62
Expired	**(528)**	**20.99**	(4,056)	25.26
Outstanding, End of Year	**15,270**	**14.87**	15,482	14.92
Exercisable, End of Year	**10,736**	**17.42**	8,523	18.66

Table of Contents

As at December 31, 2017	Outstanding TSARs			Exercisable TSARs	
Range of Exercise Price (C$)	Number of TSARs (thousands of units)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Number of TSARs (thousands of units)	Weighted Average Exercise Price (C$)
0.00 to 9.99	**3,910**	**5.17**	**5.56**	**952**	**5.56**
10.00 to 19.99	**7,816**	**1.74**	**16.93**	**6,241**	**17.43**
20.00 to 29.99	**3,544**	**1.15**	**20.57**	**3,543**	**20.57**
	15,270	**2.48**	**14.87**	**10,736**	**17.42**

During the year, Encana recorded compensation costs of $12 million related to the TSARs (2016 - compensation costs of $39 million; 2015 - reduction of compensation costs of $12 million).

As at December 31, 2017, there was approximately $8 million of total unrecognized compensation costs (2016 - $17 million) related to unvested TSARs held by employees. The costs are expected to be recognized over a weighted average period of 1.9 years.

B) PERFORMANCE TANDEM STOCK APPRECIATION RIGHTS

In 2013, Encana granted Performance TSARs to the President & Chief Executive Officer. The Performance TSARs vested and expired over the same terms and conditions as the underlying option. Under this 2013 grant, vesting was also subject to Encana achieving prescribed performance targets over a four-year period based on Encana s share price performance. As at December 31, 2017, all remaining Performance TSARs have expired and there are no remaining obligations associated with this grant.

During the year, Encana recorded a reduction of compensation costs of $2 million related to the Performance TSARs (2016 - compensation costs of $2 million; 2015 - reduction of compensation costs of $1 million).

C) STOCK APPRECIATION RIGHTS

Since 2010, U.S. dollar denominated SARs have been granted to eligible U.S. based employees, which entitle the employee to receive a cash payment equal to the excess of the market price of Encana s common shares at the time of exercise over the original grant price of the right.

The following tables summarize information related to U.S. dollar denominated SARs held by employees:

As at December 31	**2017**		2016	
(thousands of units)	**Outstanding**	**Weighted**	Outstanding	Weighted

	SARs	**Average Exercise Price (US$)**	SARs	Average Exercise Price (US$)
Outstanding, Beginning of Year	**6,721**	**14.55**	10,137	20.26
Granted	**349**	**11.75**	1,453	4.06
Exercised	**(147)**	**4.69**	-	-
Forfeited	**(418)**	**17.94**	(1,464)	18.65
Expired	**(162)**	**20.57**	(3,405)	25.32
Outstanding, End of Year	**6,343**	**14.25**	6,721	14.55
Exercisable, End of Year	**4,611**	**16.85**	3,782	18.02

Table of Contents

As at December 31, 2017	Outstanding SARs			Exercisable SARs	
Range of Exercise Price (US$)	Number of SARs (thousands of units)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (US$)	Number of SARs (thousands of units)	Weighted Average Exercise Price (US$)
0.00 to 9.99	**1,311**	**5.17**	**4.06**	**301**	**4.06**
10.00 to 19.99	**4,707**	**1.59**	**16.52**	**3,985**	**17.36**
20.00 to 29.99	**325**	**1.58**	**22.46**	**325**	**22.46**
	6,343	**2.33**	**14.25**	**4,611**	**16.85**

During the year, Encana recorded compensation costs of $6 million related to the SARs (2016 - compensation costs of $13 million; 2015 - reduction of compensation costs of $5 million).

As at December 31, 2017, there was approximately $4 million of unrecognized compensation costs (2016 - $7 million) related to unvested SARs held by employees. The costs are expected to be recognized over a weighted average period of 1.5 years.

D) PERFORMANCE SHARE UNITS

Since 2010, PSUs have been granted to eligible employees, which entitle the employee to receive, upon vesting, a cash payment equal to the value of one common share of Encana for each PSU held, depending upon the terms of the PSU Plan. PSUs vest three years from the date granted, provided the employee remains actively employed with Encana on the vesting date. Based on the performance assessment, up to a maximum of two times the original PSU grant may be eligible to vest in respect of the year being measured. The respective proportion of the original PSU grant deemed eligible to vest for each year will be valued and the notional cash value deposited to a PSU account, with payout deferred to the final vesting date.

The ultimate value of the PSUs will depend upon Encana s performance relative to predetermined corresponding performance targets measured over a three-year period. For grants commencing in 2013, performance is measured over a three-year period relative to a specified peer group.

The following table summarizes information related to the PSUs:

	Canadian Dollar Denominated		U.S. Dollar Denominated	
(thousands of units)	Outstanding PSUs		Outstanding PSUs	
	2017	2016	**2017**	2016

As at December 31				
Unvested and Outstanding, Beginning of Year	**5,218**	2,603	**2,907**	1,025
Granted	**1,234**	3,559	**704**	2,245
Vested and Released	**(433)**	-	**(123)**	-
Units, in Lieu of Dividends	**33**	38	**18**	21
Forfeited	**(50)**	(982)	**(131)**	(384)
Unvested and Outstanding, End of Year	**6,002**	5,218	**3,375**	2,907

During the year, Encana recorded compensation costs of $48 million related to the outstanding PSUs (2016 - compensation costs of $29 million; 2015 - compensation costs of $1 million).

As at December 31, 2017, there was approximately $53 million of total unrecognized compensation costs (2016 - $60 million) related to unvested PSUs held by employees. The costs are expected to be recognized over a weighted average period of 1.1 years.

Table of Contents

E) DEFERRED SHARE UNITS

The Company has in place a program whereby Directors and certain key employees are issued DSUs, which vest immediately, are equivalent in value to a common share of the Company and are settled in cash.

Under the DSU Plan, employees have the option to convert either 25 or 50 percent of their annual High Performance Results (HPR) award into DSUs. The number of DSUs converted is based on the value of the award divided by the closing value of Encana s share price at the end of the performance period of the HPR award.

For both Directors and employees, DSUs can only be redeemed following departure from Encana in accordance with the terms of the respective DSU Plan and must be redeemed prior to December 15th of the year following the departure from Encana.

The following table summarizes information related to the DSUs:

	Canadian Dollar Denominated	
(thousands of units)	**Outstanding DSUs**	
As at December 31	**2017**	2016
Outstanding, Beginning of Year	**920**	753
Granted	**134**	139
Converted from HPR awards	**16**	43
Units, in Lieu of Dividends	**5**	6
Redeemed	**(180)**	(21)
Outstanding, End of Year	**895**	920

During the year, Encana recorded compensation costs of $3 million related to the outstanding DSUs (2016 - compensation costs of $7 million; 2015 - reduction of compensation costs of $5 million).

F) RESTRICTED SHARE UNITS

Since 2011, RSUs have been granted to eligible employees. An RSU is a conditional grant to receive the equivalent of an Encana common share upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. RSUs vest three years from the date granted, provided the employee remains actively employed with Encana on the vesting date. As at December 31, 2017, Encana intends to settle the RSUs in cash on the vesting date.

The following table summarizes information related to the RSUs:

	Canadian Dollar Denominated	**U.S. Dollar Denominated**
(thousands of units)	**Outstanding RSUs**	**Outstanding RSUs**

As at December 31	**2017**	2016	**2017**	2016
Unvested and Outstanding, Beginning of Year	**10,998**	8,114	**10,418**	5,909
Granted	**2,411**	7,209	**2,434**	7,826
Units, in Lieu of Dividends	**60**	82	**59**	80
Vested and Released	**(2,088)**	(2,840)	**(1,268)**	(1,446)
Forfeited	**(352)**	(1,567)	**(1,109)**	(1,951)
Unvested and Outstanding, End of Year	**11,029**	10,998	**10,534**	10,418

During the year, Encana recorded compensation costs of $98 million related to the outstanding RSUs (2016 - compensation costs of $84 million; 2015 - reduction of compensation costs of $7 million).

As at December 31, 2017, there was approximately $99 million of total unrecognized compensation costs (2016 - $117 million) related to unvested RSUs held by employees. The costs are expected to be recognized over a weighted average period of 1.1 years.

Table of Contents

The Company sponsors defined benefit and defined contribution plans and provides pension and other post-employment benefits (OPEB) to its employees in Canada and the U.S. As of January 1, 2003, the defined benefit pension plan was closed to new entrants. The average remaining service period of active employees participating in the defined benefit pension plan is seven years and the average remaining life expectancy of inactive employees is 15 years. The average remaining service period of the active employees participating in the OPEB plan is 13 years.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years, or more frequently if directed by the regulator. The most recent filing was dated December 31, 2016 and the next required filing is expected to be as at December 31, 2019.

The following tables set forth changes in the benefit obligations and fair value of plan assets for the Company s defined benefit pension and other post-employment benefit plans for the years ended December 31, 2017 and 2016, as well as the funded status of the plans and amounts recognized in the Consolidated Financial Statements as at December 31, 2017 and 2016.

	Pension Benefits		OPEB	
As at December 31	**2017**	2016	**2017**	2016
Change in Benefit Obligations				
Projected Benefit Obligation, Beginning of Year	**$ 211**	$ 212	**$ 92**	$ 96
Service Cost	**1**	2	**8**	10
Interest Cost	**7**	8	**3**	4
Actuarial (Gains) Losses	**7**	6	**(8)**	(14)
Exchange Differences	**15**	6	**-**	2
Employee Contributions	**-**	-	**1**	1
Benefits Paid	**(15)**	(23)	**(6)**	(7)
Curtailment	**-**	-	**(5)**	-
Projected Benefit Obligation, End of Year	**$ 226**	$ 211	**$ 85**	$ 92
Change in Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**$ 194**	$ 208	**$ -**	$ -
Actual Return on Plan Assets	**15**	9	**-**	-

Exchange Differences	**14**	7	**-**	-
Employee Contributions	**-**	-	**1**	1
Employer Contributions	**2**	-	**5**	6
Benefits Paid	**(15)**	(23)	**(6)**	(7)
Transfers to Defined Contribution Plan	**-**	(7)	**-**	-
Fair Value of Plan Assets, End of Year	**$ 210**	$ 194	**$ -**	$ -
Funded Status of Plan Assets, End of Year	**$ (16)**	$ (17)	**$ (85)**	$ (92)
Total Recognized Amounts in the Consolidated Balance Sheet Consist of:				
Other Assets	**$ 4**	$ 1	**$ -**	$ -
Current Liabilities	**-**	-	**(7)**	(7)
Non-Current Liabilities	**(20)**	(18)	**(78)**	(85)
Total	**$ (16)**	$ (17)	**$ (85)**	$ (92)
Total Recognized Amounts in Accumulated Other Comprehensive Income Consist of:				
Net Actuarial (Gains) Losses	**$ 28**	$ 28	**$ (35)**	$ (28)
Net Prior Service Costs	**(5)**	(5)	**(5)**	(7)
Total Recognized in Accumulated Other Comprehensive Income, Before Tax	**$ 23**	$ 23	**$ (40)**	$ (35)

Table of Contents

The accumulated defined benefit obligation for all defined benefit plans was $310 million as at December 31, 2017 (2016 - $300 million).

The following table sets forth the defined benefit plans with accumulated benefit obligation and projected benefit obligation in excess of the fair value of the plan assets:

	Pension Benefits		OPEB	
As at December 31	**2017**	2016	**2017**	2016
Projected Benefit Obligation	**$ (77)**	$ (211)	**$ (85)**	$ (92)
Accumulated Benefit Obligation	**(76)**	(208)	**(85)**	(92)
Fair Value of Plan Assets	**57**	194	**-**	-

Following are the weighted average assumptions used by the Company in determining the defined benefit pension and other post-employment benefit obligations:

	Pension Benefits		OPEB	
As at December 31	**2017**	2016	**2017**	2016
Discount Rate	**3.25%**	3.50%	**3.44%**	3.80%
Rates of Increase in Compensation Levels	**3.49%**	3.49%	**5.04%**	5.04%

The following sets forth total benefit plans expense recognized by the Company:

	Pension Benefits			OPEB		
For the years ended December 31	**2017**	2016	2015	**2017**	2016	2015
Net Defined Periodic Benefit Cost	**$ -**	$ (1)	$ 1	**$ 3**	$ 13	$ 14
Defined Contribution Plan Expense	**24**	25	33	**-**	-	-
	$ 24	$ 24	$ 34	**$ 3**	$ 13	$ 14

Total Benefit Plans Expense												

Of the total benefit plans expense, $25 million (2016 - $28 million; 2015 - $39 million) was included in operating expense, $8 million (2016 - $9 million; 2015 - $9 million) was included in administrative expense and a gain of $6 million (2016 - nil; 2015 - nil) was included in other (gains) losses, net.

The net defined periodic benefit cost is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2017**	2016	2015	**2017**	2016	2015
Service Cost	**$ 1**	$ 2	$ 2	**$ 8**	$ 10	$ 10
Interest Cost	**7**	8	9	**3**	4	4
Expected Return on Plan Assets	**(9)**	(11)	(12)	**-**	-	-
Amounts Reclassified from Accumulated						
Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses	**1**	-	2	**(1)**	(1)	-
Amortization of net prior service costs	**-**	-	-	**(1)**	-	-
Curtailment	**-**	-	-	**(1)**	-	-
Curtailment	**-**	-	-	**(5)**	-	-
Total Net Defined Periodic Benefit Cost	**$ -**	$ (1)	$ 1	**$ 3**	$ 13	$ 14

Table of Contents

The amounts recognized in other comprehensive income are as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2017**	2016	2015	2017	2016	2015
Net Actuarial (Gains) Losses	**$ 1**	$ 8	$ (22)	**$ (8)**	$ (14)	$ (24)
Amortization of Net Actuarial Gains and (Losses)	**(1)**	-	(2)	**1**	1	-
Amortization of Net Prior Service Costs	**-**	-	-	**1**	-	-
Curtailment	**-**	-	-	**1**	-	-
Total Amounts Recognized in Other Comprehensive (Income) Loss, Before Tax	**$ -**	$ 8	$ (24)	**$ (5)**	$ (13)	$ (24)
Total Amounts Recognized in Other Comprehensive (Income) Loss, After Tax	**$ -**	$ 6	$ (17)	**$ (3)**	$ (9)	$ (16)

The estimated net actuarial loss and net prior service costs for the pension and other post-retirement plans that will be amortized from accumulated other comprehensive income into the defined periodic benefit plan expense in 2018 is $2 million.

Following are the weighted average assumptions used by the Company in determining the net periodic pension and other post-retirement benefit costs:

	Pension Benefits			OPEB		
For the years ended December 31	**2017**	2016	2015	**2017**	2016	2015
Discount Rate	**3.50%**	3.75%	3.75%	**3.76%**	4.05%	3.66%
Long-Term Rate of Return on Plan Assets	**5.25%**	6.25%	6.25%	**-**	-	-
Rates of Increase in Compensation Levels	**3.49%**	3.49%	3.99%	**6.10%**	6.43%	6.47%

The Company s assumed health care cost trend rates are as follows:

For the years ended December 31	**2017**	2016	2015

Health Care Cost Trend Rate for Next Year	**6.98%**	7.30%	7.41%
Rate to Which the Cost Trend Rate is Assumed to Decline (Ultimate Trend Rate)	**5.00%**	5.00%	5.00%
Year that the Rate Reaches the Ultimate Trend Rate	**2025**	2026	2026

A one percent change in the assumed health care cost trend rate over the projected period would have the following effects:

	1% Increase	**1% Decrease**
Effect on Total of Service and Interest Cost Components	**$ 1**	**$ (1)**
Effect on Other Post-Retirement Benefit Obligations	**$ 6**	**$ (5)**

The Company expects to contribute $2 million to its defined benefit pension plans in 2018. The Company s OPEB plans are funded on an as required basis.

Table of Contents

The following provides an estimate of benefit payments for the next 10 years. These estimates reflect benefit increases due to continuing employee service.

	Defined Benefit Pension Payments	Other Benefit Payments
2018	$ 15	$ 6
2019	15	7
2020	15	7
2021	14	7
2022	14	7
2023 - 2027	66	27

The Company s registered and other defined benefit pension plan assets are presented by investment asset category and input level within the fair value hierarchy as follows:

As at December 31	2017			
	Level 1	Level 2	Level 3	Total
Investments:				
Cash and Cash Equivalents	$ 27	$ 1	$ -	$ 28
Fixed Income - Canadian Bond Funds	-	67	-	67
Equity - Domestic	13	41	-	54
Equity - International	-	50	-	50
Real Estate and Other	-	-	11	11
Fair Value of Plan Assets, End of Year	$ 40	$ 159	$ 11	$ 210

As at December 31	2016			
	Level 1	Level 2	Level 3	Total
Investments:				
Cash and Cash Equivalents	$ 27	$ 1	$ -	$ 28
Fixed Income - Canadian Bond Funds	-	61	-	61
Equity - Domestic	12	38	-	50
Equity - International	-	45	-	45

Real Estate and Other	-	-	10	10
Fair Value of Plan Assets, End of Year	$ 39	$ 145	$ 10	$ 194

Fixed Income investments consist of Canadian bonds issued by investment grade companies. Equity investments consist of both domestic and international securities. The fair values of these securities are based on dealer quotes, quoted market prices and net asset values. Real Estate and Other consists mainly of commercial properties and is valued based on a discounted cash flow model.

A summary in changes in Level 3 fair value measurements is presented below:

	Real Estate and Other	
As at December 31	**2017**	2016
Balance, Beginning of Year	**$ 10**	$ 10
Purchases, Sales and Settlements		
Purchases and sales	**-**	-
Settlements	**-**	-
Actual Return on Plan Assets		
Relating to assets sold during the reporting period	**-**	-
Relating to assets still held at the reporting date	**1**	-
Transfers In and Out of Level 3	**-**	-
Balance, End of Year	**$ 11**	$ 10

Table of Contents

Encana s registered pension plan assets were invested by the Company in the following as at December 31, 2017: 27 percent Domestic Equity (2016 - 26 percent), 23 percent Foreign Equity (2016 - 23 percent), 43 percent Bonds (2016 - 44 percent), and 7 percent Real Estate and Other (2016 - 7 percent). The expected long-term rate of return is 4.25 percent. The expected rate of return on pension plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The actual return on plan assets was $15 million (2016 - $9 million). The asset allocation structure is subject to diversification requirements and constraints, which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of those instruments. Fair value information related to pension plan assets is included in Note 20.

Recurring fair value measurements are performed for risk management assets and liabilities and other derivative contracts, as discussed further in Note 22. These items are carried at fair value in the Consolidated Balance Sheet and are classified within the three levels of the fair value hierarchy in the following tables. There have been no significant transfers between the hierarchy levels during the period.

Fair value changes and settlements for amounts related to risk management assets and liabilities are recognized in revenues, transportation and processing expense, and foreign exchange gains and losses according to their purpose.

As at December 31, 2017	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [1]	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	**$ -**	**$ 189**	**$ -**	**$ 189**	**$ (15)**	**$ 174**
Long-term assets	**-**	**248**	**-**	**248**	**(2)**	**246**
Foreign Currency Derivatives:						
Current assets	**-**	**31**	**-**	**31**	**-**	**31**
Risk Management Liabilities						
Commodity Derivatives:						

Current liabilities	$ 3	$ 196	$ 51	$ 250	$ (15)	$ 235
Long-term liabilities	-	15	-	15	(2)	13
Foreign Currency Derivatives:						
Current liabilities	-	1	-	1	-	1
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	$ -	$ 5	$ -	$ 5	$ -	$ 5
Long-term in other liabilities and provisions	-	14	-	14	-	14

(1) Netting to offset derivative assets and liabilities where the legal right and intention to offset exists, or where counterparty master netting arrangements contain provisions for net settlement.

Table of Contents

As at December 31, 2016	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [1]	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	$ -	$ 11	$ -	$ 11	$ (11)	$ -
Long-term assets	-	19	-	19	(3)	16
Risk Management Liabilities						
Commodity Derivatives:						
Current liabilities	$ -	$ 228	$ 36	$ 264	$ (11)	$ 253
Long-term liabilities	-	38	-	38	(3)	35
Foreign Currency Derivatives:						
Current liabilities	-	1	-	1	-	1
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	$ -	$ 5	$ -	$ 5	$ -	$ 5
Long-term in other liabilities and provisions	-	14	-	14	-	14

(1) Netting to offset derivative assets and liabilities where the legal right and intention to offset exists, or where counterparty master netting arrangements contain provisions for net settlement.

The Company s Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts, NYMEX call options, foreign currency swaps and basis swaps with terms to 2023. Level 2 also includes financial guarantee contracts as discussed in Note 22. The fair values of these contracts are based on a market approach and are estimated using inputs which are either directly or indirectly observable at the reporting date, such as exchange and other published prices, broker quotes and observable trading activity.

Level 3 Fair Value Measurements

As at December 31, 2017, the Company s Level 3 risk management assets and liabilities consist of WTI three-way options and WTI costless collars with terms to 2018. The WTI three-way options are a combination of a sold call, bought put and a sold put. The WTI costless collars are a combination of a sold call and a bought put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with complete (collars) or partial (three-way) downside price protection through the put options. The fair values of the WTI three-way options and WTI costless collars are based on the income approach and are modelled using observable and unobservable inputs such as implied volatility. The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness.

A summary of changes in Level 3 fair value measurements is presented below:

	Risk Management	
	2017	2016
Balance, Beginning of Year	**$ (36)**	$ 16
Total Gains (Losses)	**(21)**	(16)
Purchases, Sales, Issuances and Settlements:		
Purchases, sales and issuances	**-**	-
Settlements	**6**	(26)
Transfers Out of Level 3 [(1)]	**-**	(10)
Balance, End of Year	**$ (51)**	$ (36)
Change in Unrealized Gains (Losses) Related to Assets and Liabilities Held at End of Year	**$ (51)**	$ (27)

(1) The Company s policy is to recognize transfers out of Level 3 on the date of the event of change in circumstances that caused the transfer.

Table of Contents

Quantitative information about unobservable inputs used in Level 3 fair value measurements is presented below:

As at December 31	Valuation Technique	Unobservable Input	2017	2016
Risk Management - WTI Options	Option Model	Implied Volatility	**17% - 76%**	18% - 64%

A 10 percent increase or decrease in implied volatility for the WTI options would cause a corresponding $2 million (2016 - $3 million) increase or decrease to net risk management assets and liabilities.

A) FINANCIAL INSTRUMENTS

Encana s financial assets and liabilities are recognized in cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, other liabilities and provisions and long-term debt.

B) RISK MANAGEMENT ACTIVITIES

Encana uses derivative financial instruments to manage its exposure to cash flow variability from commodity prices and fluctuating foreign currency exchange rates. The Company does not apply hedge accounting to any of its derivative financial instruments. As a result, gains and losses from changes in the fair value are recognized in net earnings.

COMMODITY PRICE RISK

Commodity price risk arises from the effect that fluctuations in future commodity prices may have on future cash flows. To partially mitigate exposure to commodity price risk, the Company has entered into various derivative financial instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company s policy is to not use derivative financial instruments for speculative purposes.

Crude Oil and NGLs - To partially mitigate crude oil and NGL commodity price risk, the Company uses WTI-based contracts such as fixed price contracts, options and costless collars. Encana has also entered into basis swaps to manage against widening price differentials between various production areas and benchmark price points.

Natural Gas - To partially mitigate natural gas commodity price risk, the Company uses NYMEX-based contracts such as fixed price contracts, options and costless collars. Encana has also entered into basis swaps to manage against widening price differentials between various production areas and benchmark price points.

FOREIGN EXCHANGE RISK

Foreign exchange risk arises from changes in foreign currency exchange rates that may affect the fair value or future cash flows of the Company s financial assets or liabilities. To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at December 31, 2017, Encana has entered into $650 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7597 to C$1, which mature monthly throughout 2018.

Table of Contents

RISK MANAGEMENT POSITIONS AS AT DECEMBER 31, 2017

	Notional Volumes	Term	Average Price	Fair Value
Crude Oil and NGL Contracts			**US$/bbl**	
Fixed Price Contracts				
WTI Fixed Price	71.2 Mbbls/d	2018	53.28	**$ (152)**
WTI Three-Way Options				
Sold call / bought put / sold put	16.0 Mbbls/d	2018	54.49 / 47.17 / 36.88	**(35)**
WTI Costless Collars				
Sold call / bought put	10.0 Mbbls/d	2018	57.08 / 45.00	**(16)**
Basis Contracts [1]		2018 - 2020		**(41)**
Crude Oil and NGLs Fair Value Position				**(244)**
Natural Gas Contracts			**US$/Mcf**	
Fixed Price Contracts				
NYMEX Fixed Price	673 MMcf/d	2018	3.07	**59**
NYMEX Call Options				
Sold call price	230 MMcf/d	2018	3.75	**(3)**
Sold call price	230 MMcf/d	2019	3.75	**(6)**
Basis Contracts [2]		2018		**118**
		2019		**107**
		2020		**83**
		2021 - 2023		**58**
Natural Gas Fair Value Position				**416**
Other Derivative Contracts				
Fair Value Position				**(19)**
Foreign Currency Contracts				
Fair Value Position [3]		2018		**30**
Total Fair Value Position				**$ 183**

(1) Encana has entered into swaps to protect against widening Midland, Magellan East Houston, Louisiana Light Sweet and Edmonton Condensate differentials to WTI.
(2) Encana has entered into swaps to protect against widening AECO, Dawn, Malin and Waha basis to NYMEX.
(3)

Encana has entered into U.S. dollar denominated fixed-for-floating average currency swaps to protect against fluctuations between the Canadian and U.S. dollars.

Table of Contents

EARNINGS IMPACT OF REALIZED AND UNREALIZED GAINS (LOSSES) ON RISK MANAGEMENT POSITIONS

For the years ended December 31	**2017**	2016	2015
Realized Gains (Losses) on Risk Management			
Commodity and Other Derivatives:			
Revenues [1]	**$ 40**	$ 361	$ 917
Transportation and processing	**(4)**	(8)	(16)
Foreign Currency Derivatives:			
Foreign exchange	**15**	-	-
	$ 51	$ 353	$ 901
Unrealized Gains (Losses) on Risk Management			
Commodity and Other Derivatives:			
Revenues [2]	**$ 442**	$ (636)	$ (325)
Transportation and processing	**-**	22	(6)
Foreign Currency Derivatives:			
Foreign exchange	**32**	(1)	-
	$ 474	$ (615)	$ (331)
Total Realized and Unrealized Gains (Losses) on Risk Management, net			
Commodity and Other Derivatives:			
Revenues [1] [2]	**$ 482**	$ (275)	$ 592
Transportation and processing	**(4)**	14	(22)
Foreign Currency Derivatives:			
Foreign exchange	**47**	(1)	-
	$ 525	$ (262)	$ 570

(1) Includes a realized gain of $7 million for the year ended December 31, 2017 (2016 - gain of $6 million; 2015 - gain of $1 million) related to other derivative contracts.

(2) Includes an unrealized loss of $2 million for the year ended December 31, 2017 (2016 - gain of $5 million; 2015 - nil) related to other derivative contracts.

RECONCILIATION OF UNREALIZED RISK MANAGEMENT POSITIONS FROM JANUARY 1 TO DECEMBER 31

	2017	2016	2015

	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ (292)**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**525**	**$ 525**	$ (262)	$ 570
Settlement of Other Derivative Contracts	**7**			
Fair Value of Other Derivative Contracts Entered into During the Year	**(6)**			
Fair Value of Contracts Realized During the Year	**(51)**	**(51)**	(353)	(901)
Fair Value of Contracts, End of Year	**$ 183**	**$ 474**	$ (615)	$ (331)

Risk management assets and liabilities arise from the use of derivative financial instruments and are measured at fair value. See Note 21 for a discussion of fair value measurements.

Table of Contents

UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	**2017**	2016
Risk Management Assets		
Current	**$ 205**	$ -
Long-term	**246**	16
	451	16
Risk Management Liabilities		
Current	**236**	254
Long-term	**13**	35
	249	289
Other Derivative Contracts		
Current in accounts payable and accrued liabilities	**5**	5
Long-term in other liabilities and provisions	**14**	14
Net Risk Management Assets (Liabilities) and Other Derivative Contracts	**$ 183**	$ (292)

SUMMARY OF UNREALIZED RISK MANAGEMENT POSITIONS

As at December 31	**2017**			2016		
	Risk Management			Risk Management		
	Asset	**Liability**	**Net**	Asset	Liability	Net
Commodity Price Positions						
Crude oil and NGLs	**$ -**	**$ 244**	**$ (244)**	$ 2	$ 100	$ (98)
Natural gas	**420**	**4**	**416**	14	188	(174)
Other Positions						
Other derivative contracts	**-**	**19**	**(19)**	-	19	(19)
Foreign currency contracts	**31**	**1**	**30**	-	1	(1)
Total Fair Value Position	**$ 451**	**$ 268**	**$ 183**	$ 16	$ 308	$ (292)

C) CREDIT RISK

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. While exchange-traded contracts are subject to nominal credit

risk due to the financial safeguards established by the New York Stock Exchange and Toronto Stock Exchange, over-the-counter traded contracts expose Encana to counterparty credit risk. This credit risk exposure is mitigated through the use of credit policies approved by the Board of Directors governing the Company s credit portfolio including credit practices that limit transactions according to counterparties credit quality. Mitigation strategies may include master netting arrangements, requesting collateral and/or transacting credit derivatives. The Company executes commodity derivative financial instruments under master agreements that have netting provisions that provide for offsetting payables against receivables. As a result of netting provisions, the Company s maximum exposure to loss under derivative financial instruments due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts, as disclosed in Note 21. As at December 31, 2017, the Company had no significant credit derivatives in place and held no collateral.

As at December 31, 2017, cash equivalents include high-grade, short-term securities, placed primarily with financial institutions and companies with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions that have investment grade credit ratings.

A substantial portion of the Company s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2017, approximately 92 percent (2016 - 90 percent) of Encana s accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at December 31, 2017, Encana had three counterparties whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net risk management contracts by counterparty. As at

Table of Contents

December 31, 2017, these counterparties accounted for 56 percent, 11 percent and 11 percent of the fair value of the outstanding in-the-money net risk management contracts. As at December 31, 2016, Encana had one counterparty whose net settlement position accounted for 84 percent of the fair value of the outstanding in-the-money net risk management contracts.

During 2015 and 2017, Encana entered into agreements resulting from divestitures, which may require Encana to fulfill certain payment obligations on the take or pay volume commitments assumed by the purchasers. The circumstances that would require Encana to perform under the agreements include events where a purchaser fails to make payment to the guaranteed party and/or a purchaser is subject to an insolvency event. The agreements have remaining terms from four to seven years with a fair value recognized of $19 million as at December 31, 2017 (2016 - $19 million). The maximum potential amount of undiscounted future payments is $347 million as at December 31, 2017, and is considered unlikely.

23. Supplementary Information

Supplemental disclosures to the Consolidated Statement of Cash Flows are presented below:

A) NET CHANGE IN NON-CASH WORKING CAPITAL

For the years ended December 31	2017	2016	2015
Operating Activities			
Accounts receivable and accrued revenues	$ (21)	$ 86	$ 314
Accounts payable and accrued liabilities	(226)	(233)	(14)
Income tax receivable and payable	(6)	(40)	(38)
	$ (253)	$ (187)	$ 262

B) NON-CASH ACTIVITIES

For the years ended December 31	2017	2016	2015
Non-Cash Investing Activities			
Asset retirement obligation incurred (See Note 14)	$ 11	$ 18	$ 19
Asset retirement obligation change in estimated future cash outflows (See Note 14)	88	(99)	115
Property, plant and equipment accruals	19	5	(346)
Capitalized long-term incentives (See Note 19)	55	40	(10)
Property additions/dispositions	194	100	12
Non-Cash Financing Activities			
Common shares issued under dividend reinvestment plan (See Note 15)	$ 1	$ 1	$ 73

C) SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31	**2017**	2016	2015
Interest Paid	**$ 370**	$ 397	$ 602
Income Taxes Paid, net of Amounts (Recovered)	**$ (77)**	$ (19)	$ (105)

Table of Contents

COMMITMENTS

The following table outlines the Company s commitments as at December 31, 2017:

	Expected Future Payments						
(undiscounted)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and Processing	$ 604	$ 701	$ 670	$ 571	$ 529	$ 2,315	**$ 5,390**
Drilling and Field Services	198	39	21	8	-	-	**266**
Operating Leases	18	16	16	15	15	46	**126**
Total	$ 820	$ 756	$ 707	$ 594	$ 544	$ 2,361	**$ 5,782**

Included within transportation and processing in the table above are certain commitments associated with midstream service agreements with VMLP as described in Note 17. Divestiture transactions can reduce certain commitments disclosed above.

CONTINGENCIES

Encana is involved in various legal claims and actions arising in the normal course of the Company s operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana s financial position, cash flows or results of operations. Management s assessment of these matters may change in the future as certain of these matters are in early stages or are subject to a number of uncertainties. For material matters that the Company believes an unfavourable outcome is reasonably possible, the Company discloses the nature and a range of potential exposures. If an unfavourable outcome were to occur, there exists the possibility of a material impact on the Company s consolidated net earnings or loss for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Such accruals are based on the Company s information known about the matters, estimates of the outcomes of such matters and experience in handling similar matters.

Table of Contents

25. Supplementary Oil and Gas Information (unaudited)

The unaudited supplementary information on oil and gas exploration and production activities for 2017, 2016 and 2015 has been presented in accordance with the FASB s ASC Topic 932, Extractive Activities - Oil and Gas and the SEC s final rule, Modernization of Oil and Gas Reporting . Disclosures by geographic area include Canada and the United States.

Proved Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and proved undeveloped reserves, net of third-party royalty interests of oil, NGLs and natural gas owned at each year end and changes in proved reserves during each of the last three years.

The Company s estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and government restrictions. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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

	Oil & NGLs			Natural Gas
	WTI	Edmonton Condensate [2]	Henry Hub	AECO
	($/bbl)	(C$/bbl)	($/MMBtu)	(C$/MMBtu)
Reserves Pricing [1]				
2017	**51.34**	**67.65**	**2.98**	**2.32**
2016	42.75	55.39	2.49	2.17
2015	50.28	61.94	2.58	2.69

(1) All prices were held constant in all future years when estimating net revenues and reserves.
(2) Edmonton Condensate benchmark price has replaced the previously disclosed Edmonton Light Sweet benchmark price.

Table of Contents

PROVED RESERVES [1]

(12-MONTH AVERAGE TRAILING PRICES)

	Oil (MMbbls)			NGLs (MMbbls)			Natural Gas (Bcf)			Total (MMBOE)
	Canada	United States	Total	Canada	United States	Total	Canada	United States	Total	
2015										
Beginning of year	10.9	194.1	205.0	66.6	90.2	156.7	3,229	2,265	5,494	1,277.4
Revisions and improved recovery [2]	(0.9)	(73.6)	(74.6)	(14.8)	(41.1)	(55.9)	(801)	(342)	(1,144)	(321.1)
Extensions and discoveries	-	68.4	68.4	19.8	24.9	44.7	313	159	472	191.7
Purchase of reserves in place	-	-	-	-	-	-	-	-	-	-
Sale of reserves in place	(1.6)	(1.2)	(2.8)	(0.4)	(3.6)	(4.0)	(434)	(728)	(1,163)	(200.6)
Production	(2.0)	(29.7)	(31.8)	(8.3)	(8.6)	(16.9)	(354)	(241)	(596)	(148.0)
End of year	6.4	157.9	164.3	62.8	61.7	124.5	1,952	1,112	3,064	799.4
Developed	5.0	91.6	96.6	31.8	37.8	69.5	1,295	928	2,223	536.6
Undeveloped	1.3	66.3	67.7	31.0	24.0	55.0	657	184	841	262.8
Total	**6.4**	**157.9**	**164.3**	**62.8**	**61.7**	**124.5**	**1,952**	**1,112**	**3,064**	**799.4**
2016										
Beginning of year	6.4	157.9	164.3	62.8	61.7	124.5	1,952	1,112	3,064	799.4
Revisions and improved recovery [2]	(0.3)	(15.6)	(15.9)	(6.4)	(1.6)	(8.0)	(422)	177	(244)	(64.7)
Extensions and discoveries	-	52.2	52.2	58.1	17.7	75.8	796	91	887	275.7
Purchase of reserves in place	-	9.6	9.6	-	2.6	2.6	-	16	16	14.9
Sale of reserves in place	(5.4)	(22.2)	(27.6)	(11.3)	(15.5)	(26.8)	(163)	(150)	(313)	(106.5)

Production	(0.7)	(26.2)	(27.0)	(9.2)	(8.5)	(17.7)	(354)	(153)	(506)	(129.1)
End of year	-	155.6	155.6	94.0	56.4	150.4	1,810	1,093	2,902	789.7
Developed	-	82.5	82.5	25.6	31.8	57.4	903	951	1,853	448.8
Undeveloped	-	73.1	73.1	68.4	24.6	93.0	907	142	1,049	341.0
Total	**-**	**155.6**	**155.6**	**94.0**	**56.4**	**150.4**	**1,810**	**1,093**	**2,902**	**789.7**
2017										
Beginning of year	-	155.6	155.6	94.0	56.4	150.4	1,810	1,093	2,902	789.7
Revisions and improved recovery [(2)]	0.2	(16.0)	(15.8)	(14.6)	(3.6)	(18.1)	(31)	(27)	(58)	(43.6)
Extensions and discoveries	0.2	84.9	85.1	46.4	26.5	72.9	727	144	871	303.1
Purchase of reserves in place	-	0.8	0.8	-	0.4	0.4	-	2	2	1.5
Sale of reserves in place	-	(5.4)	(5.4)	(0.2)	(3.6)	(3.8)	(65)	(729)	(795)	(141.6)
Production	(0.2)	(27.7)	(27.8)	(10.6)	(8.7)	(19.3)	(306)	(97)	(403)	(114.3)
End of year	0.2	192.3	192.5	115.0	67.5	182.5	2,135	384	2,519	794.9
Developed	0.2	104.7	104.9	40.5	41.6	82.1	1,082	243	1,325	407.8
Undeveloped	-	87.7	87.7	74.5	25.8	100.3	1,053	141	1,195	387.1
Total	**0.2**	**192.3**	**192.5**	**115.0**	**67.5**	**182.5**	**2,135**	**384**	**2,519**	**794.9**

(1) Numbers may not add due to rounding.
(2) Changes in reserve estimates resulting from application of improved recovery techniques are nil and are included in revisions of previous estimates.
Definitions:

a. 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.
b. 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.
c. 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.

Table of Contents

Total Proved reserves increased 5.2 MMBOE in 2017 due to the following:

- Revisions and improved recovery of oil, NGLs and natural gas were negative primarily due to negative revisions of 83.3 MMBOE resulting from changes in the approved development plan, which was partially offset by positive revisions of 32.6 MMBOE due to higher 12-month average trailing oil, NGL and natural gas prices.

- Extensions and discoveries of oil, NGLs and natural gas increased proved reserves by 303.1 MMBOE due to the extension of proved acreage primarily from successful drilling in the Permian, Montney and Eagle Ford assets.

- Sale of reserves in place decreased proved developed reserves by 141.6 MMBOE primarily due to the divestiture of the Piceance assets located in northwestern Colorado.

Total Proved reserves decreased 9.7 MMBOE in 2016 due to the following:

- Revisions and improved recovery of oil and NGLs included reductions of 6.5 MMbbls and 6.6 MMbbls, respectively, due to lower 12-month average trailing oil and NGL prices. Revisions and improved recovery of natural gas included a reduction of 462 Bcf due to a lower 12-month average trailing natural gas price.

- Extensions and discoveries of oil, NGLs and natural gas increased proved reserves by 275.7 MMBOE due to the extension of proved acreage primarily from successful drilling in the Permian and Montney assets.

- Sale of reserves in place decreased proved developed reserves by 65.4 MMBOE and proved undeveloped reserves by 41.2 MMBOE due to the divestitures of the DJ Basin assets located in northern Colorado and the Gordondale assets located in northwestern Alberta.

Total Proved reserves decreased 478.0 MMBOE in 2015 due to the following:

- Revisions and improved recovery of oil and NGLs included reductions of 59.9 MMbbls and 52.6 MMbbls, respectively, due to significantly lower 12-month average trailing oil and NGL prices. Revisions and improved recovery of natural gas included a reduction of 1,106 Bcf due to a significantly lower 12-month average trailing natural gas price.

- Extensions and discoveries of oil, NGLs and natural gas increased proved reserves by 191.7 MMBOE due to the extension of proved acreage primarily from successful drilling in the Montney and Permian assets.

-

Sale of reserves in place decreased proved developed reserves by 137.4 MMBOE and proved undeveloped reserves by 63.2 MMBOE due to the divestitures of the Haynesville natural gas assets located in northern Louisiana and certain assets in Wheatland located in central and southern Alberta.

Table of Contents

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

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. Estimates of future net cash flows from proved reserves are computed based on the average beginning-of-the-month prices during the 12-month period for the year. Future production and development costs include estimates for abandonment and dismantlement costs associated with asset retirement obligations and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The effect of tax credits is also considered in determining the income tax expense. The discount was computed by application of a 10 percent discount factor to the future net cash flows.

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.

	Canada [1]			United States [1]			Total [1]		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Future cash inflows	**$ 7,850**	$ 5,341	$ 6,284	**$ 11,459**	$ 8,537	$ 9,462			
Less future:									
Production costs	**3,516**	2,876	3,800	**3,661**	3,539	3,959			
Development costs	**2,058**	1,949	1,742	**3,042**	2,805	3,130			
Income taxes	**76**	-	-	**-**	-	-			
Future net cash flows	**2,200**	516	742	**4,756**	2,193	2,373			
Less 10% annual discount for estimated timing of cash flows	**618**	77	107	**2,025**	957	960			
Discounted future net cash flows	**$ 1,582**	$ 439	$ 635	**$ 2,731**	$ 1,236	$ 1,413			

Future cash inflows	**$ 19,309**	$ 13,878	$ 15,746
Less future:			
Production costs	**7,177**	6,415	7,759
Development costs	**5,100**	4,754	4,872
Income taxes	**76**	-	-
Future net cash flows	**6,956**	2,709	3,115
Less 10% annual discount for estimated timing of cash flows	**2,643**	1,034	1,067
Discounted future net cash flows	**$ 4,313**	$ 1,675	$ 2,048

(1) The standardized measure of future net cash flows relating to proved oil and gas reserves was amended to include estimated abandonment and reclamation costs associated with proved undeveloped locations, which reduced the standardized measure by $13 million and $16 million in 2016 and 2015, respectively.

Table of Contents

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

	Canada [1]			United States [1]		
	2017	2016	2015	**2017**	2016	2015
Balance, beginning of year	**$ 439**	$ 635	$ 4,476	**$ 1,236**	$ 1,413	$ 7,074
Changes resulting from:						
Sales of oil and gas produced during the year	**(471)**	(316)	(988)	**(1,291)**	(1,040)	(1,276)
Discoveries and extensions, net of related costs	**582**	211	109	**1,141**	267	504
Purchases of proved reserves in place	**-**	-	-	**13**	47	-
Sales and transfers of proved reserves in place	**(12)**	(71)	(674)	**(413)**	(220)	(1,604)
Net change in prices and production costs	**893**	20	(3,075)	**2,183**	325	(3,239)
Revisions to quantity estimates	**(22)**	(124)	(1,355)	**(203)**	39	(2,183)
Accretion of discount	**44**	64	565	**124**	141	833
Development costs incurred during the period	**454**	286	460	**1,366**	873	1,874
Changes in estimated future development costs	**(279)**	(304)	(13)	**(1,433)**	(456)	(1,809)
Other	**7**	38	(45)	**8**	(153)	(16)
Net change in income taxes	**(53)**	-	1,175	**-**	-	1,255
Balance, end of year	**$ 1,582**	$ 439	$ 635	**$ 2,731**	$ 1,236	$ 1,413

	Total [1]		
	2017	2016	2015

Balance, beginning of year	**$ 1,675**	$ 2,048	$ 11,550
Changes resulting from:			
Sales of oil and gas produced during the year	**(1,762)**	(1,356)	(2,264)
Discoveries and extensions, net of related costs	**1,723**	478	613
Purchases of proved reserves in place	**13**	47	-
Sales and transfers of proved reserves in place	**(425)**	(291)	(2,278)
Net change in prices and production costs	**3,076**	345	(6,314)
Revisions to quantity estimates	**(225)**	(85)	(3,538)
Accretion of discount	**168**	205	1,398
Development costs incurred during the period	**1,820**	1,159	2,334
Changes in estimated future development costs	**(1,712)**	(760)	(1,822)
Other	**15**	(115)	(61)
Net change in income taxes	**(53)**	-	2,430
Balance, end of year	**$ 4,313**	$ 1,675	$ 2,048

(1) The standardized measure of future net cash flows relating to proved oil and gas reserves was amended to include estimated abandonment and reclamation costs associated with proved undeveloped locations, which reduced the standardized measure by $13 million, $16 million and $7 million in 2016, 2015 and 2014, respectively.

Table of Contents

RESULTS OF OPERATIONS

The following table sets forth revenue and direct cost information relating to the Company s oil and gas exploration and production activities.

	Canada			United States		
	2017	2016	2015	**2017**	2016	2015
Oil, NGL and natural gas revenues, net of transportation and processing	**$ 613**	$ 491	$ 1,168	**$ 1,714**	$ 1,510	$ 1,911
Less:						
Operating costs, production, mineral and other taxes, and accretion of asset retirement obligation	**164**	197	199	**438**	499	661
Depreciation, depletion and amortization	**236**	260	305	**530**	523	1,088
Impairments	**-**	493	-	**-**	903	6,473
Operating income (loss)	**213**	(459)	664	**746**	(415)	(6,311)
Income taxes	**58**	(123)	179	**161**	(150)	(2,285)
Results of operations	**$ 155**	$ (336)	$ 485	**$ 585**	$ (265)	$ (4,026)

	Total		
	2017	2016	2015
Oil, NGL and natural gas revenues, net of transportation and processing	**$ 2,327**	$ 2,001	$ 3,079
Less:			
Operating costs, production, mineral	**602**	696	860

and other taxes, and accretion of asset retirement obligation			
Depreciation, depletion and amortization	**766**	783	1,393
Impairments	**-**	1,396	6,473
Operating income (loss)	**959**	(874)	(5,647)
Income taxes	**219**	(273)	(2,106)
Results of operations	**$ 740**	$ (601)	$ (3,541)

CAPITALIZED COSTS

Capitalized costs include the cost of properties, equipment and facilities for oil and natural gas producing activities. Capitalized costs for proved properties include costs for oil and natural gas leaseholds where proved reserves have been identified, development wells and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified.

	Canada			**United States**		
	2017	2016	2015	**2017**	2016	2015
Proved oil and gas properties	**$ 14,555**	$ 13,159	$ 14,866	**$ 25,610**	$ 26,393	$ 25,723
Unproved oil and gas properties	**311**	285	334	**4,169**	4,913	5,282
Total capital cost	**14,866**	13,444	15,200	**29,779**	31,306	31,005
Accumulated DD&A	**14,047**	12,896	14,170	**23,240**	25,300	23,822
Net capitalized costs	**$ 819**	$ 548	$ 1,030	**$ 6,539**	$ 6,006	$ 7,183

	Other			**Total**		
	2017	2016	2015	**2017**	2016	2015
Proved oil and gas properties	**$ 63**	$ 58	$ 58	**$ 40,228**	$ 39,610	$ 40,647
Unproved oil and gas properties	**-**	-	-	**4,480**	5,198	5,616

Total capital cost	**63**	58	58	**44,708**	44,808	46,263
Accumulated DD&A	**63**	58	58	**37,350**	38,254	38,050
Net capitalized costs	**$ -**	$ -	$ -	**$ 7,358**	$ 6,554	$ 8,213

Table of Contents

COSTS INCURRED

Costs incurred includes both capitalized costs and costs charged to expense when incurred. Costs incurred also includes internal costs directly related to acquisition, exploration, and development activities, new asset retirement costs established in the current year as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year.

	Canada			United States		
	2017	2016	2015	**2017**	2016	2015
Acquisition costs						
Unproved	**$ 31**	$ -	$ 2	**$ 21**	$ 4	$ 15
Proved	**-**	1	7	**2**	205	12
Total acquisition costs	**31**	1	9	**23**	209	27
Exploration costs	**1**	1	3	**4**	13	3
Development costs	**425**	255	377	**1,354**	860	1,844
Total costs incurred	**$ 457**	$ 257	$ 389	**$ 1,381**	$ 1,082	$ 1,874

	Total		
	2017	2016	2015
Acquisition costs			
Unproved	**$ 52**	$ 4	$ 17
Proved	**2**	206	19
Total acquisition costs	**54**	210	36
Exploration costs	**5**	14	6
Development costs	**1,779**	1,115	2,221
Total costs incurred	**$ 1,838**	$ 1,339	$ 2,263

COSTS NOT SUBJECT TO DEPLETION OR AMORTIZATION

Upstream costs in respect of significant unproved properties are excluded from the country cost centre s depletable base as follows:

As at December 31	**2017**	2016
Canada		
	$ 311	$ 285
United States	**4,169**	4,913
	$ 4,480	$ 5,198

The following is a summary of the costs related to Encana s unproved properties as at December 31, 2017:

2017	2016	2015	Prior to 2015	Total

Acquisition Costs	$ 245	$ 104	$ 29	$ 3,965	**$ 4,343**
Exploration Costs	2	5	8	122	**137**
	$ 247	$ 109	$ 37	$ 4,087	**$ 4,480**

Acquisition costs primarily include costs incurred to acquire or lease properties. Exploration costs primarily include costs related to geological and geophysical studies and costs of drilling and equipping exploratory wells. Ultimate recoverability of these costs and the timing of inclusion within the applicable country cost centre s depletable base is dependent upon either the finding of proved oil, NGL and natural gas reserves, expiration of leases or recognition of impairments.

Included in the $4.5 billion of oil and gas properties not subject to depletion or amortization are approximately $4.0 billion of acquired leasehold and mineral costs in the Permian related to the Company s acquisition of Athlon Energy Inc. in 2014. These acquisition costs are associated with acquired acreage for which proved reserves have yet to be assigned from future development. The Company continually assesses the development timeline of the acquired acreage. The timing and amount of the transfer of property acquisition costs into the depletable base are based on several factors and may be subject to changes over time from drilling plans, drilling results, availability of capital, project economics and other assessments of the

Table of Contents

property. The inclusion of these acquisition costs in the depletable base is expected to occur within 8 to 12 years. The remaining costs excluded from depletion are related to properties which are not individually significant.

The following summarizes quarterly financial data for the fiscal years of 2017 and 2016:

	2017			
(US$ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1 (1)**
Revenues	**$ 1,210**	**$ 861**	**$ 1,083**	**$ 1,289**
Impairments	**-**	**-**	**-**	**-**
Operating Income (Loss)	**262**	**(4)**	**321**	**489**
Gain (Loss) on Divestitures, net	**(1)**	**406**	**-**	**(1)**
Net Earnings (Loss) Before Income Tax	**$ 147**	**$ 522**	**$ 327**	**$ 434**
Income Tax Expense (Recovery)	**376**	**228**	**(4)**	**3**
Net Earnings (Loss)	**$ (229)**	**$ 294**	**$ 331**	**$ 431**
Net Earnings (Loss) per Common Share - Basic & Diluted	**$ (0.24)**	**$ 0.30**	**$ 0.34**	**$ 0.44**

(1) Corporate interest income of $8 million previously reported in revenues and operating income (loss) in Q1 2017 has been reclassified to other (gains) losses, net.

	2016			
(US$ millions, except per share amounts)	Q4	Q3	Q2	Q1
Revenues	$ 822	$ 979	$ 364	$ 753
Impairments	-	-	484	912
Operating Income (Loss)	(54)	128	(912)	(1,043)
Gain (Loss) on Divestitures, net	(3)	395	(2)	-
Net Earnings (Loss) Before Income Tax	$ (251)	$ 379	$ (1,068)	$ (680)
Income Tax Expense (Recovery)	30	62	(467)	(301)
Net Earnings (Loss)	$ (281)	$ 317	$ (601)	$ (379)
Net Earnings (Loss) per Common Share - Basic & Diluted	$ (0.29)	$ 0.37	$ (0.71)	$ (0.45)

Table of Contents

Item 9: Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

The financial statements for the fiscal years ended December 31, 2017, 2016, and 2015, included in this Annual Report on Form 10-K, have been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report appearing herein. There have been no changes in or disagreements with the accountants during the periods presented.

Item 9A: Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Encana s Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company s disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. The Company s disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is accumulated and communicated to the Company s management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company s disclosure controls and procedures are effective as of December 31, 2017.

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See Management s Assessment of Internal Control Over Financial Reporting under Item 8 of this Annual Report on Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See Report of Independent Registered Public Accounting Firm under Item 8 of this Annual Report on Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Encana s internal control over financial reporting during the fourth quarter of 2017 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting. See Management s Assessment of Internal Control Over Financial Reporting under Item 8 of this Annual Report on Form 10-K.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS

Information regarding the Board of Directors is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

Information regarding the Company s executive officers is located under Executive Officers of the Registrant under Item 1 and 2 of this Annual Report on Form 10-K.

CODE OF ETHICS

Encana has adopted a code of ethics entitled the Business Code of Conduct (the Code of Ethics), that applies to its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions. The Code of Ethics is available for viewing on Encana s website at www.encana.com, and is available in print to any shareholder who requests it. Requests for copies of the Code of Ethics should be made by contacting Encana s Corporate Secretary, 4400, 500 Centre Street S.E., P.O. Box 2850, Calgary, Alberta T2P 2S5, Canada, telephone: (403) 645-2000. Encana intends to disclose and summarize any amendment to, or waiver from, any provision of the Code of Ethics that is required to be so disclosed and summarized, on its website at www.encana.com.

Item 11. Executive Compensation

The information required by this Item 11 is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

The executive compensation and related information incorporated by reference herein shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The information required by this Item 12 is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item 13 is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item 14 is set forth in the Proxy Statement relating to the Company s 2018 annual meeting of shareholders, which is incorporated herein by reference.

127

Table of Contents

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this Annual Report on Form 10-K or incorporated by reference:

1. Consolidated Financial Statements

Reference is made to the Consolidated Financial Statements and notes thereto appearing in Item 8 of this Annual Report on Form 10-K.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the Consolidated Financial Statements or notes thereto.

3. Exhibits

Exhibits are listed in the exhibit index below. The exhibits include management contracts, compensatory plans and arrangements required to be filed as exhibits to the Annual Report on Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

Exhibit No	Description
3.1	Restated Certificate of Incorporation and Restated Articles of Incorporation dated November 30, 2009 (incorporated by reference to Exhibit 99.2 to Encana s Report on Form 6-K filed on December 2, 2009, SEC File No. 001-15226).
3.2	Certificate of Amendment and Articles of Amendment dated May 12, 2015 (incorporated by reference to Exhibit 99.1 to Encana s Report on Form 6-K filed on May 19, 2015, SEC File No. 001-15226).
3.3	By-Law No. 1 of Encana Corporation effective February 11, 2014 (incorporated by reference to Exhibit 99.1 to Encana s Report on Form 6-K filed on May 15, 2014, SEC File No. 001-15226).
4.1	Amended and Restated Shareholder Rights Plan Agreement dated as of May 3, 2016 between Encana Corporation and CST Trust Company as Rights Agent (incorporated by reference to Exhibit 99.1 to Encana s Report on Form 6-K filed on May 5, 2016, SEC File No. 001-15226).
4.2	Amended and Restated Dividend Reinvestment Plan dated as of March 25, 2013 (incorporated by reference to Exhibit 4.2 to Encana s Registration Statement on Form F-3 filed on March 25, 2013, SEC File No. 333-187492).
4.3	6.50% Notes due 2019 (incorporated by reference to Exhibit 4.3 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.4	3.90% Notes due 2021 (incorporated by reference to Exhibit 4.4 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.5	8.125% Notes due 2030 (incorporated by reference to Exhibit 4.5 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.6	7.2% Notes due 2031 (incorporated by reference to Exhibit 4.6 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.7	7.375% Notes due 2031 (incorporated by reference to Exhibit 4.7 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).

4.8	6.50% Notes due 2034 (incorporated by reference to Exhibit 4.8 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.9	6.625% Notes due 2037 (incorporated by reference to Exhibit 4.9 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.10	6.50% Notes due 2038 (incorporated by reference to Exhibit 4.10 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.11	5.15% Notes due 2041 (incorporated by reference to Exhibit 4.11 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.12	Indenture dated as of August 13, 2007 between Encana Corporation and The Bank of New York (incorporated by reference to Exhibit 4.12 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.13	Indenture dated as of November 14, 2011 between Encana Corporation and The Bank of New York Mellon (incorporated by reference to Exhibit 7.1 to Encana s Registration Statement on Form F-10 filed on May 7, 2012, SEC File No. 333-181196).
4.14	Indenture dated as of September 15, 2000 between Encana Corporation (as successor by amalgamation to Alberta Energy Company Ltd.) and The Bank of New York (incorporated by reference to Exhibit 4.14 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.15	First Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of September 15, 2000 between Encana Corporation and The Bank of New York (incorporated by reference to Exhibit 4.15 to Encana s Annual Report

	on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.16	Second Supplemental Indenture dated as of November 20, 2012 to the Indenture dated as of September 15, 2000 between Encana Corporation and The Bank of New York (incorporated by reference to Exhibit 4.16 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.17	Indenture dated as of November 5, 2001 between Encana Corporation (as successor by amalgamation to PanCanadian Petroleum Limited) and The Bank of Nova Scotia Trust Company of New York (incorporated by reference to Exhibit 4.17 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.18	First Supplemental Indenture dated as of January 1, 2002 to the Indenture dated as of November 5, 2001 between Encana Corporation (as successor by amalgamation to PanCanadian Petroleum Limited) and The Bank of Nova Scotia Trust Company of New York (incorporated by reference to Exhibit 4.18 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.19	Second Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of November 5, 2001 between Encana Corporation and The Bank of Nova Scotia Trust Company of New York (incorporated by reference to Exhibit 4.19 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.20	Third Supplemental Indenture as of November 20, 2012 to the Indenture dated as of November 5, 2001 between Encana Corporation and The Bank of Nova Scotia Trust Company of New York (incorporated by reference to Exhibit 4.20 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.21	Fourth Supplemental Indenture dated as of July 24, 2013 to the Indenture dated as of November 5, 2001 between Encana Corporation and The Bank of Nova Scotia Trust Company of New York (incorporated by reference to Exhibit 4.21 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.22	Indenture dated as of October 2, 2003 between Encana Corporation and The Bank of New York (incorporated by reference to Exhibit 4.22 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
4.23	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.2 to Encana s Registration Statement on Form F-3 filed on July 25, 2016, SEC File No. 333-212667).
10.1	Restated Credit Agreement dated as of July 16, 2015 among Encana Corporation as Borrower, the financial and other institutions named therein as Lenders and Royal Bank of Canada as Agent (incorporated by reference to Exhibit 10.1 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.2	Second Amended and Restated Credit Agreement dated as of October 20, 2011 among Alenco Inc. as Borrower, the banks, financial institutions and other institutional lenders party thereto and Citibank N.A. as Administrative Agent (incorporated by reference to Exhibit 10.2 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.3	A letter amendment to the Second Amended and Restated Credit Agreement dated as of October 20, 2011 among Alenco Inc. as Borrower, the banks, financial institutions and other institutional lenders party thereto and Citibank N.A. as Administrative Agent, dated as of June 15, 2012 (incorporated by reference to Exhibit 10.3 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.4	Amendment No. 2 to the Second Amended and Restated Credit Agreement dated as of October 20, 2011 among Alenco Inc. as Borrower, the banks, financial institutions and other institutional lenders party thereto and Citibank N.A. as Administrative Agent, dated as of June 28, 2013 (incorporated by reference to Exhibit 10.4 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.5	

	Amendment No. 3 to the Second Amended and Restated Credit Agreement dated as of October 20, 2011 among Alenco Inc. as Borrower, the banks, financial institutions and other institutional lenders party thereto and Citibank N.A. as Administrative Agent, dated as of July 16, 2015 (incorporated by reference to Exhibit 10.5 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226)
10.6*	Encana Corporation Employee Stock Option Plan reflective with amendments made as of April 27, 2005, as of April 25, 2007, as of April 22, 2008, as of October 22, 2008, as of November 30, 2009, as of July 20, 2010, as of February 24, 2015 and as of February 22, 2016 (incorporated by reference to Exhibit 10.6 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.7*	Form of Executive Stock Option Grant Agreement.
10.8*	Encana Corporation Employee Stock Appreciation Rights Plan, adopted with effect from February 12, 2008, as amended December 9, 2008, November 30, 2009, April 20, 2010, July 20, 2010, February 24, 2015, February 22, 2016 and February 14, 2018.
10.9*	Form of Executive Stock Appreciation Rights Grant Agreement (incorporated by reference to Exhibit 10.9 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.10*	Performance Share Unit Plan for Employees of Encana Corporation Amended and restated with effect from January 1, 2010, and reflective with amendments made as of July 20, 2010, February 24, 2015, February 22, 2016 and February 14, 2018.
10.11*	Form of Canadian Executive PSU Grant Agreement.
10.12*	Form of U.S. Executive PSU Grant Agreement.
10.13*	Restricted Share Unit Plan for Employees of Encana Corporation established with effect from February 8, 2011, and

Table of Contents

	reflective with amendments made as of February 24, 2015, February 22, 2016 and February 14, 2018.
10.14*	Form of Canadian Executive RSU Grant Agreement (incorporated by reference to Exhibit 10.14 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.15*	Form of U.S. Executive RSU Grant Agreement (incorporated by reference to Exhibit 10.15 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.16*	Deferred Share Unit Plan for Employees of Encana Corporation adopted with effect from December 18, 2002 and reflective of amendments made as of October 23, 2007, October 22, 2008, and July 20, 2010 (incorporated by reference to Exhibit 10.16 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.17*	Deferred Share Unit Plan for Directors of Encana Corporation adopted with effect from December 18, 2002 and reflective with amendments made as of April 26, 2005, October 22, 2008, December 8, 2009, July 20, 2010, February 13, 2013, December 1, 2014 and February 14, 2018.
10.18*	Amended and Restated Change in Control Agreement between Encana Corporation and Sherri A. Brillon effective February 14, 2018.
10.19*	Amended and Restated Change in Control Agreement between Encana Corporation and Renee E. Zemljak effective February 14, 2018.
10.20*	Amended and Restated Change in Control Agreement between Encana Corporation and Michael G. McAllister effective February 14, 2018.
10.21*	Amended and Restated Change in Control Agreement between Encana Corporation and Douglas J. Suttles effective February 14, 2018.
10.22*	Amended and Restated Change in Control Agreement between Encana Corporation and David G. Hill effective February 14, 2018.
10.23*	Amended and Restated Change in Control Agreement between Encana Corporation and Michael Williams effective February 14, 2018.
10.24*	Amended and Restated Change in Control Agreement between Encana Corporation and Joanne L. Alexander effective February 14, 2018.
10.25*	Form of Director and Officer Indemnification Agreement effective as of July 20, 2016 between Encana Corporation and each of its directors and officers (incorporated by reference to Exhibit 10.25 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.26*	Encana Corporation Canadian Pension Plan Amended and Restated as of January 1, 2011 (incorporated by reference to Exhibit 10.26 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.27*	Amendment No. 1 to the Encana Corporation Canadian Pension Plan amended and restated as of January 1, 2011, dated as of May 29, 2014 (incorporated by reference to Exhibit 10.27 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.28*	Amendment No. 2 to the Encana Corporation Canadian Pension Plan amended and restated as of January 1, 2011, dated as of November 24, 2014 (incorporated by reference to Exhibit 10.28 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.29*	Amendment No. 3 to the Encana Corporation Canadian Pension Plan amended and restated as of January 1, 2011, dated as of November 30, 2015 (incorporated by reference to Exhibit 10.29 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.30*	Encana Corporation Canadian Supplemental Pension Plan amended and restated effective April 1, 2015 (incorporated by reference to Exhibit 10.30 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.31*	Encana Corporation Canadian Investment Plan effective September 1, 2002 (incorporated by reference to Exhibit 10.31 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.32*	

	Encana (USA) Retirement Plan amended and restated effective March 14, 2014 (incorporated by reference to Exhibit 10.32 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.33*	Amendment No. 1 to Encana (USA) Retirement Plan amended and restated effective March 14, 2014, dated May 1, 2014 (incorporated by reference to Exhibit 10.33 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.34*	Amendment No. 2 to Encana (USA) Retirement Plan amended and restated effective March 14, 2014, dated August 7, 2014 (incorporated by reference to Exhibit 10.34 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.35*	Amendment No. 3 to Encana (USA) Retirement Plan amended and restated effective March 14, 2014, dated December 28, 2015 (incorporated by reference to Exhibit 10.35 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.36*	Alenco Inc. Deferred Compensation Plan amended and restated effective January 1, 2009 (incorporated by reference to Exhibit 10.36 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.37*	Amendment No. 1 to Alenco Inc. Deferred Compensation Plan amended and restated effective January 1, 2009, effective January 1, 2012 (incorporated by reference to Exhibit 10.37 to Encana s Annual Report on Form 10-K filed on February 27, 2017, SEC File No. 001-15226).
10.38*	Restricted Share Unit Plan for Directors of Encana Corporation effective February 14, 2018.
10.39*	Form of Director RSU Grant Agreement.
12.1	Consolidated Statement of Computation of Ratio of Earnings to Fixed Charges.

Table of Contents

14.1	Business Code of Conduct effective March 27, 2013 (incorporated by reference to Exhibit 99.1 to Encana s Report on Form 6-K filed on March 27, 2013, SEC File No. 001-15226).
21.1	Encana Corporation Significant Subsidiaries.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of McDaniel & Associates Consultants Ltd.
23.3	Consent of Netherland, Sewell & Associates, Inc.
24.1	Power of Attorney (included on the signature page of this report).
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
99.1	Report of McDaniel & Associates Consultants Ltd.
99.2	Report of Netherland, Sewell & Associates, Inc.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.

* Management contract or compensatory arrangement.

Item 16. Form 10-K Summary

None.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

ENCANA CORPORATION

By: /s/ Sherri A. Brillon
Name: Sherri A. Brillon
Title: Executive Vice-President & Chief Financial Officer

Dated: February 26, 2018

Table of Contents

SIGNATURES WITH RESPECT TO ENCANA CORPORATION

POWERS OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Douglas J. Suttles and Sherri A. Brillon, and each of them, any of whom may act without the joinder of the other, the true and lawful attorney-in-fact and agent of the undersigned, with full power of substitution and resubstitution, for and in the name, place and stead of the undersigned, in any and all capacities, to sign any and all amendments, including any post-effective amendments, and supplements to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Commission, and hereby grants to such attorney-in-fact and agent, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

This Power of Attorney may be executed in multiple counterparts, each of which shall be deemed an original, but which taken together shall constitute one instrument.

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Annual Report on Form 10-K has been signed by the following persons in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ Clayton H. Woitas	Chairman of the Board	February 26, 2018
Clayton H. Woitas	of Directors	
/s/ Douglas J. Suttles	President & Chief Executive Officer and	February 26, 2018
Douglas J. Suttles	Director (Principal Executive Officer)	
/s/ Sherri A. Brillon	Executive Vice-President	February 26, 2018
Sherri A. Brillon	& Chief Financial Officer (Principal Financial	
	Officer and Principal Accounting Officer)	
/s/ Peter A. Dea	Corporate Director	February 26, 2018
Peter A. Dea		
/s/ Fred J. Fowler	Corporate Director	February 26, 2018
Fred J. Fowler		
/s/ Howard J. Mayson	Corporate Director	February 26, 2018
Howard J. Mayson		

/s/ Lee A. McIntire	Corporate Director	February 26, 2018
Lee A. McIntire		
/s/ Margaret A. McKenzie	Corporate Director	February 26, 2018
Margaret A. McKenzie		
/s/ Suzanne P. Nimocks	Corporate Director	February 26, 2018
Suzanne P. Nimocks		
/s/ Brian G. Shaw	Corporate Director	February 26, 2018
Brian G. Shaw		
/s/ Bruce G. Waterman	Corporate Director	February 26, 2018
Bruce G. Waterman		