2016 Q2 REPORT

For the period ended
June 30, 2016

encana

Encana delivers significant efficiency improvements with strong second quarter results
Company is positioned for growth and to strengthen balance sheet

Calgary, Alberta (July 21, 2016) **TSX, NYSE: ECA**

Encana's relentless focus on execution excellence during the second quarter has driven another step change in efficiency improvements and returns. As a result, the company has lowered cash costs, such as transportation, processing and operating expenses, and improved capital efficiency in its updated 2016 guidance. Driven by efficiency improvements, Encana is also raising its 2016 production guidance. The company expects to use proceeds from announced dispositions to further strengthen its balance sheet and increase its capital investment into high return opportunities in its core four assets.

Highlights from the quarter include:

- cash flow up over 75 percent from the previous quarter to $182 million or $0.21 per share
- operating earnings of $89 million or $0.10 per share, up from a first quarter operating loss of $130 million or $0.15 per share
- 95 percent of capital invested in high return wells in the core four assets; the Permian, Eagle Ford, Duvernay and Montney
- maintained scale in the core four assets which delivered 268,300 barrels of oil equivalent per day (BOE/d), representing 73 percent of the company's 368,300 BOE/d total production
- new Permian 14-well pad peaked at 12,000 BOE/d and is currently producing over 10,000 BOE/d gross
- announced Gordondale and DJ Basin divestitures are expected to close by the end of July 2016

"We are one of the lowest cost, highest performing operators in each of our core four plays," said Doug Suttles, Encana President & CEO. "Our success in capturing significant capital efficiency gains continues to increase our returns. By reinvesting savings and modestly increasing capital, we are adding 50 percent more drilling and completions activity to our 2016 program."

"We expect to use proceeds from announced divestitures to strengthen our balance sheet and modestly increase our 2016 capital program. We anticipate this additional activity will deliver approximately 13,000 BOE/d of production from our core four assets in the fourth quarter of this year and between 30,000 to 35,000 BOE/d in 2017, of which approximately 75 percent will be liquids," added Suttles.

Increased capital efficiency and operational performance in core four assets
Encana beat its 2016 drilling and completions cost reduction targets in the first quarter. In the second quarter the company continued to lower drilling and completion costs across its four core assets and they are now over 30 percent lower compared to the 2015 full-year average. In addition, Encana delivered new pacesetter performance and has a track record of rapidly converting pacesetter benchmarks into average costs.

In the Permian, Encana built on its track record as a leading innovator by completing the Midland Basin's first 14-well pad. This peaked at 12,000 BOE/d and is currently producing over 10,000 BOE/d gross. In addition, it delivered a 10 percent quarter-over-quarter reduction in average drilling and completions costs. These costs are 31 percent lower than the full-year 2015 average. Encana is now the second largest producer in the core of the Midland Basin.

In the Eagle Ford, Encana delivered a new pacesetter well at a cost of $3 million. Average drilling and completions costs in the second quarter in the play were 38 percent lower than the 2015 average.

In the Duvernay, Encana delivered a $6.8 million pacesetter well. The second quarter average drilling and completions costs were approximately 40 percent lower than the company's 2015 average.

In the Montney, Encana continued to deliver strong results from its condensate-rich wells in the Tower, Dawson South and Pipestone areas. Combined, these areas offer a potential inventory of almost 6,000 condensate-rich well locations. Second quarter average drilling and completions costs were down 14 percent compared to the first quarter and 33 percent lower than the full-year 2015 average.

Continued cost and capital efficiency and disciplined balance sheet management

Encana continued to capture significant cost savings during the second quarter. As a result, the company is lowering its guidance for transportation, processing and operating costs by $100 million for the year. Encana expects the full-year benefit of these savings will be even greater in 2017.

Encana is reinvesting savings from continued capital efficiency improvements and expects to use a portion of proceeds from its Gordondale and DJ Basin divestitures to increase its 2016 capital program by $200 million. As a result, after adjusting for the Gordondale divestiture, the company is increasing its 2016 production guidance and expects fourth quarter exit production decline from its core four assets to be cut from 10 percent to five percent. Encana's Gordondale and DJ Basin divestitures are expected to close by the end of July delivering proceeds of approximately $1.1 billion.

Second quarter results

Encana's core four assets contributed 268,300 BOE/d or approximately 73 percent of total second quarter production of 368,300 BOE/d. Total liquids production averaged 132,000 barrels per day (bbls/d) and natural gas production averaged 1.4 billion cubic feet per day (Bcf/d).

Encana generated second quarter cash flow of $182 million or $0.21 per share, compared to $181 million or $0.22 per share in the second quarter of 2015. The company recorded second quarter operating earnings of $89 million or $0.10 per share compared to an operating loss of $167 million or $0.20 per share in the second quarter of 2015. The second quarter net loss of $601 million, or $0.71 per share, is largely attributable to non-cash items such as after-tax ceiling test impairments and an after-tax unrealized hedging loss.

Encana's updated guidance, which reflects asset sales, cost reductions, increased capital investment and production in the core four assets, can be downloaded from the company's website at http://www.encana.com/investors/financial/corporate-guidance.html.

Encana's Risk Management Program

As at June 30, 2016, Encana has hedged approximately 78 percent of its remaining expected 2016 oil and condensate production at an average price of $55.91 per barrel and 86 percent of expected natural gas production at an average price of $2.63 per thousand cubic feet (Mcf).

Encana has about 15,500 bbls/d of expected 2017 crude and condensate hedged using WTI fixed price contracts at an average price of $49.49 per bbl. In addition, the company has hedged 10,000 bbls/d under WTI three-way options for the second half of 2017. The company also has 300 million cubic feet per day (MMcf/d) of expected 2017 natural gas production hedged under three-way options and 350 MMcf/d using NYMEX fixed price contracts for the first quarter of 2017.

For more information on the company's risk management program, refer to note 19 in the Interim Consolidated Financial Statements for the period ended June 30, 2016, available on the company's website.

Dividend Declared

On July 20, 2016, the Board declared a dividend of $0.015 per share payable on September 30, 2016 to common shareholders of record as of September 15, 2016.

Second Quarter Highlights

Financial Summary		
(for the period ended June 30) ($ millions, except per share amounts)	**Q2 2016**	Q2 2015
Cash flow[1]	**182**	181
Per share diluted	**0.21**	0.22
Operating earnings (loss)[1]	**89**	(167)
Per share diluted	**0.10**	(0.20)
Earnings Reconciliation Summary		
Net earnings (loss)	**(601)**	(1,610)
After-tax (addition) deduction:		
Unrealized hedging gain (loss)	**(310)**	(187)
Impairments	**(331)**	(1,328)
Restructuring charges	**-**	(10)
Non-operating foreign exchange gain (loss)	**(48)**	114
Gain (loss) on divestitures	**(1)**	1
Income tax adjustments	**-**	(33)
Operating earnings (loss)[1]	**89**	(167)
Per share diluted	**0.10**	(0.20)

[1] Cash flow and operating earnings are non-GAAP measures as defined in Note 1.

Production Summary			
(for the period ended June 30) (after royalties)	**Q2 2016**	Q2 2015	% Δ
Natural gas (MMcf/d)	**1,418**	1,568	(10)
Liquids (Mbbls/d)	**132.0**	127.3	4

Natural Gas and Liquids Prices		
	Q2 2016	Q2 2015
Natural gas		
NYMEX ($/MMBtu)	**1.95**	2.64
Encana realized gas price[1] **($/Mcf)**	**1.86**	3.52
Oil and NGLs ($/bbl)		
WTI	**45.59**	57.94
Encana realized liquids price[1]	**38.47**	43.78

[1] Realized prices include the impact of financial hedging.

Reporting Requirements

Effective January 1, 2017, Encana intends to comply with Securities and Exchange Commission reporting requirements applicable to U.S. domestic issuers and, accordingly, will file its annual report on Form 10-K for the year ended December 31, 2016 and regular periodic reports under both Canadian and U.S. law thereafter.

Second Quarter Conference Call

A conference call and webcast to discuss the 2016 second quarter results will be held for the investment community on July 21, 2016 at 7 a.m. MT (9 a.m. ET). To participate, please dial (866) 223-7781 (toll-free in North America) or (416) 340-2216 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 10 a.m. MT on July 21 until 11:59 p.m. MT on July 28, 2016 by dialing (800) 408-3053 or (905) 694-9451 and entering passcode 6349633.

Encana Corporation
Encana is a leading North American energy producer that is focused on developing its strong portfolio of resource plays, held directly and indirectly through its subsidiaries, producing natural gas, oil and natural gas liquids (NGLs). By partnering with employees, community organizations and other businesses, Encana contributes to the strength and sustainability of the communities where it operates. Encana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

Important Information
Encana reports in U.S. dollars unless otherwise noted. Production, sales and reserves estimates are reported on an after-royalties basis, unless otherwise noted. Per share amounts for cash flow and earnings are on a diluted 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. Unless otherwise specified or the context otherwise requires, reference to Encana or to the company includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

NOTE 1: Non-GAAP measures
This news release contains references to non-GAAP measures as follows:

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets.
- Operating earnings (loss) is a non-GAAP measure defined as net earnings (loss) excluding non-recurring or non-cash items that management believes reduces the comparability of the company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures, gains on debt retirement, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Encana’s liquidity and its ability to generate funds to finance its operations.

ADVISORY REGARDING OIL AND GAS INFORMATION - The conversion of natural gas volumes to barrels of oil equivalent (“BOE”) is on the basis of six thousand cubic feet to one barrel. 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. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

Pacesetter well costs for a particular play are a composite of the best drilling performance and best completions performance wells in the current quarter in such play and are presented for comparison purposes. Drilling and completions costs in the Permian, Eagle Ford, Duvernay and Montney have been normalized based on lateral lengths of 7,500 feet, 5,000 feet, 8,200 feet and 9,000 feet, respectively.

This news release discloses estimated well locations, which include proved, probable, contingent and unbooked locations. These estimates are prepared internally based on Encana's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Approximately 20 percent of all locations in the Montney are booked as either reserves or resources, as prepared by independent qualified reserves evaluators using forecast prices and costs as of December 31, 2015. Unbooked locations do not have attributed reserves or resources and have been identified by management as an estimation of Encana's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Encana will drill all unbooked locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The locations on which Encana will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of capital, regulatory and partner approvals, seasonal restrictions, equipment and personnel, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained, production rate recovery, transportation constraints and other factors. While certain of the unbooked locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of other unbooked locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - This news release contains certain forward-looking statements or information (collectively, "FLS") within the meaning of applicable securities legislation. FLS include: expectation of meeting or exceeding the targets in Encana's 2016 corporate guidance, including its cost savings target; expected proceeds from divestitures, expectation that the closing conditions and regulatory approvals will be satisfied, the timing of closing thereof and the use of proceeds therefrom, including expected reduction to debt and increase in capital investment and drilling and completions activity; allocation of capital and expected returns; well performance and costs relative to peers and within plays; future growth in cash flow and production, including from its core four assets and anticipated commodity mix; pacesetting operational metrics being indicative of average future well performance and costs; anticipated capital and cost efficiencies, including drilling and completion, operating, corporate, transportation and processing costs, and sustainability thereof; estimated well locations; expected offset to production reduced through divestiture; anticipated production and decline rate; reductions to cash outlay; anticipated hedging and outcomes of risk management program, including amount of hedged production; the expectation to continue to strengthen Encana's balance sheet and create additional financial flexibility; anticipated dividends; and future filings and the form thereof.

Readers are cautioned against unduly relying on FLS which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or for results to differ materially from those expressed or implied. These assumptions include: assumptions contained in Encana's 2016 corporate guidance and in this news release; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; results from innovations; expectation that counterparties will fulfill their obligations under gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; effectiveness of Encana's resource play hub model to drive productivity and efficiencies; enforceability of transaction agreements and the ability of the parties to such transactions to satisfy closing conditions and regulatory approvals; the value of adjustments to the expected proceeds from the transactions; 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, the benefits achieved and general industry expectations.

Risks and uncertainties that may affect these business outcomes include: risks inherent to closing announced divestitures on a timely basis or at all and adjustments that may reduce the expected proceeds and value to Encana; commodity price volatility; timing and costs of well, facilities and pipeline construction; ability to secure adequate product transportation and potential pipeline curtailments; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; fluctuations in currency and interest rates; risk and effect of a downgrade in credit rating, including below an investment-grade credit rating, and its impact on access to capital markets and other sources of liquidity; variability and discretion of Encana's Board to declare and pay dividends, if any; the ability to generate sufficient cash flow to meet Encana's obligations; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; Encana's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; changes in or interpretation of royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; risks associated with existing and potential future lawsuits and regulatory actions made against Encana; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business, as described in its most recent MD&A, financial statements, Annual Information Form and Form 40-F, as filed on SEDAR and EDGAR.

Although Encana believes the expectations represented by such FLS 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 are not exhaustive. FLS are made as of the date of this news release and, except as required by law, Encana undertakes no obligation to update publicly or revise any FLS. The FLS contained in this news release are expressly qualified by these cautionary statements.

Further information on Encana Corporation is available on the company's website, www.encana.com, or by contacting:

Investor contact:
Brendan McCracken
Vice-President, Investor Relations
(403) 645-2978

Patti Posadowski
Sr. Advisor, Investor Relations
(403) 645-2252

Media contact:
Simon Scott
Vice-President, Communications
(403) 645-2526

Jay Averill
Director, Media Relations
(403) 645-4747

SOURCE: Encana Corporation

Encana Corporation

Management's Discussion and Analysis

For the period ended June 30, 2016

(Prepared in U.S. Dollars)

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Encana Corporation ("Encana" or the "Company") should be read with the unaudited interim Condensed Consolidated Financial Statements for the period ended June 30, 2016 ("Interim Condensed Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2015.

The Interim Condensed Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") and in U.S. dollars, except where another currency has been indicated. References to C$ are to Canadian 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. Production volumes are presented on an after royalties basis consistent with U.S. oil and gas reporting standards. The term "liquids" is used to represent oil, natural gas liquids ("NGLs" or "NGL") and condensate. The term "liquids rich" is used to represent natural gas streams with associated liquids volumes. This document is dated July 20, 2016.

For convenience, references in this document to "Encana", the "Company", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. Non-GAAP 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: Cash Flow; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; and Debt to Adjusted Capitalization. Further information regarding these measures can be found in the Non-GAAP Measures section of this MD&A, including reconciliations of Cash from Operating Activities to Cash Flow and Free Cash Flow, and of Net Earnings (Loss) Attributable to Common Shareholders to Operating Earnings (Loss).

The following volumetric measures may be abbreviated throughout this MD&A: thousand cubic feet ("Mcf"); million cubic feet ("MMcf") per day ("MMcf/d"); barrel ("bbl"); thousand barrels ("Mbbls") per day ("Mbbls/d"); barrels of oil equivalent ("BOE") per day ("BOE/d"); thousand barrels of oil equivalent ("MBOE") per day ("MBOE/d"); million British thermal units ("MMBtu").

Readers should also read the Advisory section located at the end of this document, which provides information on Forward-Looking Statements and Oil and Gas Information.

Encana's Strategic Objectives

Encana is a leading North American energy producer that is focused on developing its strong portfolio of resource plays producing natural gas, oil and NGLs. Encana is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. The Company is pursuing the key business objectives of balancing its commodity portfolio, focusing capital investments in a limited number of core, high return and scalable projects, maintaining portfolio flexibility to respond to changing market conditions, maximizing profitability through operating efficiencies, reducing costs and preserving balance sheet strength.

Encana continually strives to improve operating efficiencies, foster technological innovation and lower its cost structures, while reducing its environmental footprint through play optimization. The Company's resource play hub model utilizes highly integrated production facilities to develop resources by drilling multiple wells from central pad sites. Capital and operating efficiencies are achieved through repeatable operations, optimizing equipment and processes and by applying continuous improvement techniques.

Encana hedges a portion of its expected natural gas, oil and NGLs production volumes. The Company's hedging program reduces volatility and helps sustain Cash Flow and Operating Netbacks during periods of lower prices. Further information on the Company's commodity price positions as at June 30, 2016 can be found in the Results Overview section of this MD&A and in Note 19 to the Interim Condensed Consolidated Financial Statements.

Additional information on expected results can be found in Encana's Corporate Guidance on the Company's website www.encana.com.

Encana's Business

Reportable Segments

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 natural gas, oil and NGLs and other related activities within Canada. Plays in Canada primarily include: Montney in northern British Columbia and northwest Alberta; Duvernay in west central Alberta; Wheatland in southern Alberta; and Deep Panuke located offshore Nova Scotia.
- **USA Operations** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S. Plays in the U.S. primarily include: Eagle Ford in south Texas; Permian in west Texas; DJ Basin in northern Colorado; San Juan in northwest New Mexico; and Piceance in northwest Colorado.
- **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. Financial information is presented on an after eliminations basis within this MD&A.

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.

Comparative figures for 2015 have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Further information regarding the reclassification can be found in the Results of Operations section of this MD&A.

Core Four Assets

Encana continually reviews and evaluates its strategy and capital investment plans in response to changing market conditions. In the current commodity price environment, Encana is focused on accelerating growth from high return scalable projects, referred to as the Core Four Assets, comprising Montney, Duvernay, Eagle Ford and Permian.

- **Montney** development is focused on exploiting natural gas and condensate in the deep basin of the Montney formation, exclusively using horizontal well technology and the application of multi-stage hydraulic fracturing. Encana has access to natural gas processing, gathering and compression capacity under contract with third parties, as well as ownership interest in additional processing plants in the play.
- **Duvernay** development is focused on exploiting shale gas and condensate in the Duvernay formation using horizontal well technology with pad drilling and the application of the resource play hub model. Encana holds ownership interest in natural gas processing plants and gathering and compression capacity in the play.
- **Eagle Ford** development is focused on exploiting tight oil in the thickest portion of the Eagle Ford shale located in the Karnes Trough, using horizontal wells drilled with tighter cluster spacing and the resource play hub model to optimize well and completions design. Encana's position is located in an area with easy access to oil markets via pipeline or truck. The Company also has access to natural gas gathering and processing capacity under contract with third parties.
- **Permian** development is focused on exploiting oil in the Midland basin, where properties are characterized by multiple producing horizons which can accommodate multiple completions per well with the potential for both vertical and horizontal drilling. Encana has focused development using horizontal well technology and multi-well horizontal pad drilling to maximize resource recovery and minimize developmental footprint. The play has an established transportation infrastructure for easy access to markets via pipeline or truck.

For additional information on the Core Four Assets, please refer to Encana's Annual Information Form ("AIF").

Results Overview

Highlights

In the three months ended June 30, 2016, Encana reported:

- Cash Flow of $182 million and Operating Earnings of $89 million.
- Net Loss of $601 million, including after-tax non-cash ceiling test impairments of $331 million and an after-tax unrealized hedging loss of $310 million.
- Average realized natural gas prices, including financial hedges, of $1.86 per Mcf. Average realized oil prices, including financial hedges, of $48.65 per bbl. Average realized NGL prices, including financial hedges, of $23.34 per bbl.
- Average natural gas production volumes of 1,418 MMcf/d and average oil and NGL production volumes of 132.0 Mbbls/d.
- Dividends paid of $0.015 per share.

In the six months ended June 30, 2016, Encana reported:

- Cash Flow of $284 million and an Operating Loss of $41 million.
- Net Loss of $980 million, including after-tax non-cash ceiling test impairments of $938 million, an after-tax unrealized hedging loss of $345 million and an after-tax non-operating foreign exchange gain of $247 million.
- Average realized natural gas prices, including financial hedges, of $2.03 per Mcf. Average realized oil prices, including financial hedges, of $45.99 per bbl. Average realized NGL prices, including financial hedges, of $20.07 per bbl.
- Average natural gas production volumes of 1,466 MMcf/d and average oil and NGL production volumes of 131.4 Mbbls/d.
- Dividends paid of $0.03 per share.
- Cash and cash equivalents of $293 million at period end.

Significant developments for the Company during the six months ended June 30, 2016 included the following:

- Announced an agreement with Birchcliff Energy Ltd. on June 21, 2016 to sell the Company's Gordondale assets, which include approximately 54,200 net acres of land and associated infrastructure located in Montney in northwestern Alberta. The transaction is expected to close in the third quarter of 2016, with an effective date of January 1, 2016, and is subject to satisfaction of normal closing conditions and regulatory approvals.
- Completed tender offers (collectively, the "Tender Offers") announced in March 2016 for certain of the Company's outstanding senior notes (collectively, the "Notes") and accepted for purchase $489 million 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.
- Completed workforce reductions announced in February 2016 to better align staffing levels and the organizational structure with the Company's reduced capital spending program as a result of the current low commodity price environment. Encana incurred restructuring charges of $31 million and reduced its workforce by approximately 16 percent.

Financial Results

	Six months ended June 30		2016		2015				2014	
($ millions, except as indicated)	**2016**	2015	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash Flow [1]	**$ 284**	$ 676	**$ 182**	$ 102	$ 383	$ 371	$ 181	$ 495	$ 377	$ 807
$ per share - diluted	**0.33**	0.85	**0.21**	0.12	0.45	0.44	0.22	0.65	0.51	1.09
Operating Earnings (Loss) [1], [2]	**(41)**	(148)	**89**	(130)	111	(24)	(167)	19	35	281
$ per share - diluted	**(0.05)**	(0.19)	**0.10**	(0.15)	0.13	(0.03)	(0.20)	0.03	0.05	0.38
Net Earnings (Loss) Attributable to Common Shareholders	**(980)**	(3,317)	**(601)**	(379)	(612)	(1,236)	(1,610)	(1,707)	198	2,807
$ per share - basic & diluted	**(1.15)**	(4.15)	**(0.71)**	(0.45)	(0.72)	(1.47)	(1.91)	(2.25)	0.27	3.79
Revenues, Net of Royalties	**1,117**	2,079	**364**	753	1,031	1,312	830	1,249	2,254	2,285
Realized Hedging Gain (Loss), before tax	**300**	401	**129**	171	287	213	161	240	124	28
Unrealized Hedging Gain (Loss), before tax	**(506)**	(414)	**(451)**	(55)	(90)	173	(278)	(136)	489	231
Upstream Operating Cash Flow	**610**	1,181	**330**	280	552	531	479	702	821	982
Upstream Operating Cash Flow excluding Realized Hedging [1]	**307**	769	**204**	103	261	314	315	454	694	952
Capital Investment	**574**	1,479	**215**	359	280	473	743	736	857	598
Net Acquisitions & (Divestitures) [3]	**(4)**	(978)	**1**	(5)	(761)	(99)	(140)	(838)	50	(2,007)
Free Cash Flow [1]	**(290)**	(803)	**(33)**	(257)	103	(102)	(562)	(241)	(480)	209
Ceiling Test Impairments, after tax	**(938)**	(2,550)	**(331)**	(607)	(514)	(1,066)	(1,328)	(1,222)	-	-
Gain (Loss) on Divestitures, after tax	**(1)**	11	**(1)**	-	-	(2)	1	10	(11)	2,399
Production Volumes										
Natural Gas (MMcf/d)	**1,466**	1,712	**1,418**	1,516	1,571	1,547	1,568	1,857	1,861	2,199
Oil & NGLs (Mbbls/d)										
Oil	**79.7**	82.7	**78.9**	80.5	90.6	91.9	86.2	79.2	68.8	62.1
NGLs	**51.7**	41.3	**53.1**	50.3	54.4	48.5	41.1	41.5	37.6	41.9
Total Oil & NGLs	**131.4**	124.0	**132.0**	130.8	145.0	140.4	127.3	120.7	106.4	104.0
Total Production (MBOE/d)	**375.8**	409.3	**368.3**	383.4	406.8	398.3	388.7	430.1	416.7	470.6
Production Mix (%)										
Natural Gas	**65**	70	**64**	66	64	65	67	72	74	78
Oil & NGLs	**35**	30	**36**	34	36	35	33	28	26	22

(1) A non-GAAP measure, which is defined in the Non-GAAP Measures section of this MD&A.
(2) In Q2 2015, organizational structure changes were formalized which resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.
(3) Excludes the impact of the PrairieSky Royalty Ltd. divestiture and the Athlon Energy Inc. acquisition during 2014. Further information on these transactions can be found in the Company's annual MD&A for the year ended December 31, 2015.

Factors Impacting Quarterly Net Earnings

Encana's quarterly net earnings can be significantly impacted by fluctuations in commodity prices, realized and unrealized hedging gains and losses, production volumes, foreign exchange rates, ceiling test impairments and gains or losses on divestitures, which are provided in the Financial Results table and the Prices and Foreign Exchange Rates table within this MD&A. Quarterly net earnings are also impacted by Encana's interim income tax expense calculated using the estimated annual effective income tax rate and a gain on debt retirement as discussed in the Other Operating Results section of this MD&A, as well as by divestiture transactions as discussed in the Net Capital Investment section of this MD&A.

Ceiling Test Impairments

Under full cost accounting, the carrying amount of Encana's natural gas and oil properties within each country cost centre is subject to a ceiling test performed quarterly. 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 Securities and Exchange Commission ("SEC") requirements using the 12-month average trailing prices and discounted at 10 percent.

In the second quarter and first six months of 2016, the Company recognized after-tax non-cash ceiling test impairments of $166 million and $361 million, respectively, in the Canadian Operations and $165 million and $577 million, respectively, in the USA Operations. The non-cash ceiling test impairments primarily resulted from the decline in the 12-month average trailing prices. Further declines in the 12-month average trailing prices could reduce proved reserves volumes and values and result in the recognition of future ceiling test impairments.

Future ceiling test impairments are difficult to reasonably predict and depend on commodity prices, as well as changes to reserves estimates, future development costs, capitalized costs and unproved property costs. Proceeds received from upstream divestitures are generally deducted from the Company's capitalized costs and can reduce the likelihood of ceiling test impairments.

The Company has calculated the estimated effects that certain price changes would have had on its ceiling test impairment for the six months ended June 30, 2016. Using the average of the price on the first day of each month from the most recent nine months ended June 30, 2016 and commodity futures prices for the three months ended September 30, 2016, the 12-month average trailing prices for the six months ended June 30, 2016 would have been $42.96 per bbl for WTI, C$53.01 per bbl for Edmonton Light Sweet, $2.28 per MMBtu for Henry Hub, and C$2.01 per MMBtu for AECO, while holding all other inputs and assumptions constant. Based on these estimated prices, an additional after-tax ceiling test impairment of $54 million for the Canadian Operations would have been recognized for the six months ended June 30, 2016. No additional impairment would have been recognized for the USA Operations. The additional estimated after-tax ceiling test impairment is partly a result of a two percent decrease in proved undeveloped reserves as certain locations would not be economic at these revised prices. This estimate strictly isolates the potential impact of commodity prices on the Company's proved reserves volumes and values. Due to uncertainties in estimating proved reserves, the additional after-tax ceiling test impairment described and resulting implications may not be indicative of Encana's future development plans, operating or financial results.

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 natural gas and oil 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 natural gas and liquids 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.

Three months ended June 30, 2016 versus June 30, 2015

Cash Flow of $182 million increased $1 million during the three months ended June 30, 2016 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, of $1.35 per Mcf decreased $1.02 per Mcf from 2015 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $135 million. Average realized liquids prices, excluding financial hedges, of $33.67 per bbl decreased $10.16 per bbl from 2015 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $117 million.
- Average natural gas production volumes of 1,418 MMcf/d decreased 150 MMcf/d from 2015 primarily due to the sale of Haynesville natural gas assets in the fourth quarter of 2015, natural declines and lower production from Deep Panuke, partially offset by successful drilling programs in the Core Four Assets. Lower natural gas volumes decreased revenues $31 million. Average oil and NGL production volumes of 132.0 Mbbls/d increased 4.7 Mbbls/d from 2015 primarily due to successful drilling programs in the Core Four Assets, partially offset by natural declines. Higher oil and NGL volumes increased revenues $17 million.
- Realized financial hedging gains before tax were $129 million compared to $161 million in 2015.
- Transportation and processing expense decreased $55 million primarily due to the expiration and renegotiation of certain transportation contracts, the sale of Haynesville natural gas assets in the fourth quarter of 2015, lower activity in Other Upstream Operations and the lower U.S./Canadian dollar exchange rate, partially offset by higher liquids processing fees in Montney and Duvernay.
- Operating expense decreased $63 million primarily due to lower activity, cost-saving initiatives and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Interest expense decreased $171 million primarily due to a one-time payment of $165 million in 2015 associated with the April 2015 early debt redemptions.

Operating Earnings in the second quarter of 2016 were $89 million compared to an Operating Loss of $167 million in 2015 due to lower depreciation, depletion and amortization (“DD&A”), foreign exchange gains on settlements and changes in deferred tax as well as the items discussed in the Cash Flow section above.

Net Loss in the second quarter of 2016 was $601 million compared to $1,610 million in 2015 due to the items discussed in the Cash Flow and Operating Earnings sections above. Net Loss in the second quarter of 2016 was also impacted by after-tax non-cash ceiling test impairments, an after-tax unrealized hedging loss and an after-tax non-operating foreign exchange loss.

Six months ended June 30, 2016 versus June 30, 2015

Cash Flow of $284 million decreased $392 million during the six months ended June 30, 2016 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, of $1.55 per Mcf decreased $1.45 per Mcf from 2015 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $404 million. Average realized liquids prices, excluding financial hedges, of $28.63 per bbl decreased $10.51 per bbl from 2015 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $248 million.
- Average natural gas production volumes of 1,466 MMcf/d decreased 246 MMcf/d from 2015 primarily due to the sale of Haynesville natural gas assets in the fourth quarter of 2015, natural declines and lower production from Deep Panuke, partially offset by successful drilling programs in the Core Four Assets. Lower natural gas volumes decreased revenues $113 million. Average oil and NGL production volumes of 131.4 Mbbls/d increased 7.4 Mbbls/d from 2015 primarily due to successful drilling programs in the Core Four Assets, partially offset by natural declines. Higher oil and NGL volumes increased revenues $55 million.
- Realized financial hedging gains before tax were $300 million compared to $401 million in 2015.
- Transportation and processing expense decreased $124 million primarily due to the expiration and renegotiation of certain transportation contracts, the sale of Haynesville natural gas assets in the fourth quarter of 2015, the lower U.S./Canadian dollar exchange rate and lower activity in Other Upstream Operations, partially offset by higher liquids processing fees in Montney and Duvernay, and higher natural gas volumes and gathering and processing fees in Montney.
- Operating expense decreased $70 million primarily due to cost-saving initiatives, lower activity and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Interest expense decreased $193 million primarily due to a one-time payment of $165 million in the second quarter of 2015 associated with the April 2015 early debt redemptions as well as lower interest on debt following these redemptions and the March 2016 early debt retirement.

Operating Loss in the first six months of 2016 was $41 million compared to $148 million in 2015 primarily due to the items discussed in the Cash Flow section above. Operating Loss in first six months of 2016 was also impacted by lower DD&A, foreign exchange gains on settlements and changes in deferred tax.

Net Loss in the first six months of 2016 was $980 million compared to $3,317 million in 2015 due to the items discussed in the Cash Flow and Operating Earnings sections above. Net Loss in the first six months of 2016 was also impacted by after-tax non-cash ceiling test impairments, an after-tax unrealized hedging loss, an after-tax non-operating foreign exchange gain, an after-tax gain on debt retirement, and changes in deferred tax.

Prices and Foreign Exchange Rates

	Six months ended June 30		2016		2015				2014	
(average for the period)	**2016**	2015	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Encana Realized Pricing										
Including Hedging										
Natural Gas ($/Mcf)	**$ 2.03**	$ 4.20	**$ 1.86**	$ 2.18	$ 3.43	$ 3.71	$ 3.52	$ 4.78	$ 4.16	$ 4.03
Oil & NGLs ($/bbl)										
Oil	**45.99**	49.80	**48.65**	43.38	49.77	49.38	53.08	46.17	80.38	90.22
NGLs	**20.07**	23.10	**23.34**	16.63	21.36	19.57	24.28	21.92	40.87	48.76
Total Oil & NGLs	**35.80**	40.91	**38.47**	33.09	39.11	39.09	43.78	37.83	66.40	73.50
Total ($/BOE)	**20.43**	29.94	**20.98**	19.89	27.19	28.17	28.53	31.24	35.55	35.06
Excluding Hedging										
Natural Gas ($/Mcf)	**1.55**	3.00	**1.35**	1.73	2.13	2.60	2.37	3.53	3.94	3.88
Oil & NGLs ($/bbl)										
Oil	**34.19**	47.15	**40.65**	27.84	37.48	42.40	53.15	40.53	66.38	90.18
NGLs	**20.05**	23.10	**23.29**	16.63	21.36	19.57	24.28	21.92	40.87	48.76
Total Oil & NGLs	**28.63**	39.14	**33.67**	23.53	31.43	34.52	43.83	34.13	57.35	73.48
Total ($/BOE)	**16.05**	24.38	**17.29**	14.85	19.44	22.26	23.90	24.82	32.25	34.36
Natural Gas Price Benchmarks										
NYMEX ($/MMBtu)	**2.02**	2.81	**1.95**	2.09	2.27	2.77	2.64	2.98	4.00	4.06
AECO (C$/Mcf)	**1.68**	2.81	**1.25**	2.11	2.65	2.80	2.67	2.95	4.01	4.22
Algonquin City Gate ($/MMBtu)	**2.86**	6.80	**2.44**	3.28	3.05	2.37	2.24	11.41	4.99	2.97
Basis Differential ($/MMBtu)										
AECO/NYMEX	**0.77**	0.53	**0.98**	0.56	0.27	0.61	0.50	0.57	0.44	0.16
Oil Price Benchmarks										
West Texas Intermediate (WTI) ($/bbl)	**39.52**	53.29	**45.59**	33.45	42.18	46.43	57.94	48.64	73.15	97.17
Edmonton Light Sweet (C$/bbl)	**47.76**	59.82	**54.73**	40.80	52.95	56.23	67.71	51.94	75.69	97.16
Foreign Exchange										
Average U.S./Canadian Dollar Exchange Rate (US$ per C$1)	**0.752**	0.810	**0.776**	0.728	0.749	0.764	0.813	0.806	0.881	0.918

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In the second quarter and first six months of 2016, Encana's average realized natural gas price, excluding hedging, reflected lower benchmark prices compared to 2015. Hedging activities contributed $0.51 per Mcf to Encana's average realized natural gas price in the second quarter of 2016 and $0.48 per Mcf in the first six months of 2016.

In the second quarter and first six months of 2016, Encana's average realized oil and NGL prices, excluding hedging, reflected lower benchmark prices compared to 2015. Hedging activities contributed $8.00 per bbl to Encana's average realized oil price in the second quarter of 2016 and $11.80 per bbl in the first six months of 2016. Hedging activities contributed $0.05 per bbl to Encana's average realized NGL price in the second quarter of 2016 and $0.02 per bbl in the first six months of 2016.

Financial Hedge Agreements

As a means of managing commodity price volatility and its impact on cash flows, Encana enters into various financial hedge agreements. Unsettled derivative financial contracts are recorded at the date of the financial statements based on the fair value of the contracts. Changes in fair value result from volatility in forward commodity prices and changes in the balance of unsettled contracts between periods. The changes in fair value are recognized in revenue as unrealized hedging gains and losses. Realized hedging gains and losses are recognized in revenue when derivative financial contracts are settled.

The tables below summarize a selection of the Company's significant hedging contracts on expected future production as at June 30, 2016.

Natural Gas

	Term	Notional Volumes (MMcf/d)	Average Price ($/Mcf)
NYMEX Fixed Price Contracts	**Q3-Q4 2016**	**859**	**2.68**
	Q1 2017	**350**	**3.07**
NYMEX Fixed Price Swaptions (1)	**2017**	**345**	**2.70**
NYMEX Three-Way Options	**2017**	**300**	
Sold call price			**3.07**
Bought put price			**2.75**
Sold put price			**2.27**
NYMEX Costless Collars	**Q3-Q4 2016**	**335**	
Sold call price			**2.46**
Bought put price			**2.22**

(1) NYMEX Fixed Price Swaptions give the counterparty the option to extend 2016 fixed price swaps to December 31, 2017 at the strike price.

Crude Oil

	Term	Notional Volumes (Mbbls/d)	Average Price ($/bbl)
WTI Fixed Price Contracts	**Q3-Q4 2016**	**46.5**	**56.35**
	2017	**15.5**	**49.49**
WTI Fixed Price Swaptions (1)	**Q2 2017**	**10.0**	**50.86**
WTI Three-Way Options	**Q3-Q4 2016**	**22.4**	
Sold call price			**62.99**
Bought put price			**55.00**
Sold put price			**47.11**
WTI Three-Way Options	**Q3-Q4 2017**	**10.0**	
Sold call price			**65.00**
Bought put price			**50.25**
Sold put price			**40.00**

(1) WTI Fixed Price Swaptions give the counterparty the option to extend first quarter 2017 fixed price swaps to June 30, 2017 at the strike price.

The Company's hedging program helps sustain Cash Flow and Operating Netbacks during periods of lower prices. For additional information, see Note 19 to the Interim Condensed Consolidated Financial Statements.

Foreign Exchange

As disclosed in the Prices and Foreign Exchange Rates table, the average U.S./Canadian dollar exchange rate decreased 0.037 in the second quarter of 2016 compared to 2015 and 0.058 in the first six months of 2016 compared to 2015. The table below summarizes selected foreign exchange impacts on Encana's financial results when compared to the same periods in 2015.

	Three months ended June 30		**Six months ended June 30**	
	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:				
Capital Investment	**$ (25)**		**$ (45)**	
Transportation and Processing Expense	**(8)**	**$ (0.23)**	**(25)**	**$ (0.36)**
Operating Expense	**(2)**	**(0.05)**	**(5)**	**(0.08)**
Administrative Expense	**(2)**	**(0.06)**	**(6)**	**(0.09)**
Depreciation, Depletion and Amortization	**(3)**	**(0.09)**	**(13)**	**(0.20)**

Price Sensitivities

Natural gas and liquids prices fluctuate in response to changing market forces, creating varying impacts on Encana's financial results. The Company's potential exposure to commodity price fluctuations is summarized in the table below, which shows the estimated effects that certain price changes would have had on the Company's Cash Flow and Operating Earnings (Loss) for the second quarter of 2016. The price sensitivities below are based on business conditions, transactions and production volumes during the second quarter of 2016. Accordingly, these sensitivities may not be indicative of financial results for other periods, under other economic circumstances or with additional fluctuations in commodity prices.

		Impact On			
		Cash Flow		Operating Earnings (Loss)	
($ millions, except as indicated)	Price Change (1)	Increase	Decrease	Increase	Decrease
Increase or Decrease in:					
NYMEX Natural Gas Price	+/- $0.25/MMBtu	**$ 5**	**$ (5)**	**$ 2**	**$ (2)**
WTI Oil Price	+/- $5.00/bbl	**$ 15**	**$ (15)**	**$ 10**	**$ (10)**

(1) Assumes only one variable changes while all other variables, including the Company's financial hedging positions, are held constant.

Net Capital Investment

($ millions)	Three months ended June 30 2016	2015	Six months ended June 30 2016	2015
Canadian Operations	**$ 54**	$ 114	**$ 117**	$ 265
USA Operations	**159**	628	**456**	1,211
Corporate & Other	**2**	1	**1**	3
Capital Investment	**215**	743	**574**	1,479
Acquisitions	**1**	3	**2**	38
Divestitures	**-**	(143)	**(6)**	(1,016)
Net Acquisitions & (Divestitures)	**1**	(140)	**(4)**	(978)
Net Capital Investment	**$ 216**	$ 603	**$ 570**	$ 501

Capital Investment by Play

($ millions)	Three months ended June 30 2016	2015	Six months ended June 30 2016	2015
Canadian Operations				
Montney	**$ 27**	$ 48	**$ 63**	$ 127
Duvernay	**27**	57	**54**	127
Other Upstream Operations				
Wheatland	**-**	4	**-**	4
Deep Panuke	**-**	1	**-**	3
Other and emerging	**-**	4	**-**	4
Total Canadian Operations	**$ 54**	$ 114	**$ 117**	$ 265
USA Operations				
Eagle Ford	**$ 38**	$ 175	**$ 114**	$ 372
Permian	**112**	325	**316**	542
Other Upstream Operations				
DJ Basin	**-**	56	**-**	144
San Juan	**-**	23	**-**	59
Piceance	**-**	3	**-**	6
Haynesville	**-**	10	**-**	12
Other and emerging	**9**	36	**26**	76
Total USA Operations	**$ 159**	$ 628	**$ 456**	$ 1,211
Core Four Assets:				
Capital Investment	**$ 204**	$ 605	**$ 547**	$ 1,168
% of Encana Capital Investment	**95**	81	**95**	79

Capital Investment

Capital investment during the first six months of 2016 was $574 million compared to $1,479 million in 2015 which reflects disciplined capital spending focused on the Core Four Assets and a reduced capital spending program as a result of the current low commodity price environment.

Divestitures

Divestitures in the first six months of 2016 were $6 million in the USA Operations, which primarily included the sale of certain properties that do not complement Encana's existing portfolio of assets.

Divestitures in the first six months of 2015 were $879 million in the Canadian Operations and $84 million in the USA Operations, which primarily included the transactions discussed below, as well as the sale of certain properties that did not complement Encana's existing portfolio of assets. The Canadian Operations included approximately C$558 million ($468 million), after closing adjustments, for the sale of the Company's working interest in certain assets in Wheatland located in central and southern Alberta, as well as approximately C$454 million ($358 million), after closing adjustments, in cash consideration net to Encana for the sale of certain natural gas gathering and compression assets in Montney in northeastern British Columbia to Veresen Midstream Limited Partnership ("VMLP"). Further information regarding VMLP can be found in Note 14 to the Interim Condensed Consolidated Financial Statements.

Amounts received from the Company's divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools.

Announced Divestitures

On October 8, 2015, the Company announced an agreement to sell to Crestone Peak Resources Holdings LLC, an entity jointly owned by the Canada Pension Plan Investment Board and The Broe Group, the Company's DJ Basin assets in Colorado, comprising approximately 51,000 net acres, with an effective date of April 1, 2015. The transaction is expected to close by the end of July 2016. The Company also announced the sale of its Gordondale assets as discussed in the Results Overview section of this MD&A. The proceeds from the announced divestitures are expected to be approximately $1.1 billion.

Production Volumes

(average daily, after royalties)	Three months ended June 30 2016	Three months ended June 30 2015	Six months ended June 30 2016	Six months ended June 30 2015
Natural Gas (MMcf/d)	**1,418**	1,568	**1,466**	1,712
Oil (Mbbls/d)	**78.9**	86.2	**79.7**	82.7
NGLs (Mbbls/d)	**53.1**	41.1	**51.7**	41.3
Total Oil & NGLs (Mbbls/d)	**132.0**	127.3	**131.4**	124.0
Total Production (MBOE/d)	**368.3**	388.7	**375.8**	409.3
Core Four Assets:				
Total Production Volumes (MBOE/d)	**268.3**	223.3	**268.7**	223.1
% of Total Encana Production Volumes	**73**	57	**72**	55

Production Volumes by Play

	Three months ended June 30				Six months ended June 30			
(average daily, after royalties)	Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)		Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Canadian Operations								
Montney	**781**	685	**21.1**	21.6	**803**	701	**21.7**	22.5
Duvernay	**57**	17	**8.8**	3.0	**52**	17	**8.2**	2.9
Other Upstream Operations								
Wheatland	**83**	76	**0.4**	1.2	**78**	94	**0.4**	1.5
Deep Panuke	**12**	32	**-**	-	**39**	107	**-**	-
Other and emerging [(1)]	**38**	71	**0.1**	0.5	**46**	85	**-**	0.1
Total Canadian Operations	**971**	881	**30.4**	26.3	**1,018**	1,004	**30.3**	27.0
USA Operations								
Eagle Ford	**50**	36	**41.0**	39.8	**48**	36	**41.4**	37.9
Permian	**52**	38	**40.8**	29.5	**49**	36	**38.5**	28.1
Other Upstream Operations								
DJ Basin	**55**	55	**10.6**	15.3	**55**	52	**11.3**	14.8
San Juan	**9**	15	**4.1**	6.4	**10**	14	**4.2**	6.6
Piceance	**275**	324	**2.8**	3.7	**280**	333	**2.9**	3.7
Haynesville	**-**	204	**-**	-	**-**	217	**-**	-
Other and emerging	**6**	15	**2.3**	6.3	**6**	20	**2.8**	5.9
Total USA Operations	**447**	687	**101.6**	101.0	**448**	708	**101.1**	97.0
Total Production Volumes	**1,418**	1,568	**132.0**	127.3	**1,466**	1,712	**131.4**	124.0
Core Four Assets:								
Total Production Volumes	**940**	776	**111.7**	93.9	**952**	790	**109.8**	91.4
% of Total Encana Production Volumes	**66**	49	**85**	74	**65**	46	**84**	74

(1) Natural gas production volumes from Bighorn have been included within Other and emerging for 2015.

Natural Gas Production Volumes

In the second quarter of 2016, average natural gas production volumes of 1,418 MMcf/d decreased 150 MMcf/d from 2015. In the first six months of 2016, average natural gas production volumes of 1,466 MMcf/d decreased 246 MMcf/d from 2015.

In the second quarter and first six months of 2016, the USA Operations volumes were lower primarily due to the sale of Haynesville natural gas assets in the fourth quarter of 2015 and natural declines in Piceance, partially offset by successful drilling programs in Permian and Eagle Ford.

In the second quarter and first six months of 2016, the Canadian Operations volumes were higher primarily due to successful drilling programs in Montney and Duvernay, partially offset by production declines at Deep Panuke resulting from a higher water production rate and a longer platform shutdown in the second quarter of 2016 compared to 2015.

Oil and NGL Production Volumes

In the second quarter of 2016, average oil and NGL production volumes of 132.0 Mbbls/d increased 4.7 Mbbls/d from 2015. In the first six months of 2016, average oil and NGL production volumes of 131.4 Mbbls/d increased 7.4 Mbbls/d from 2015.

In the second quarter and first six months of 2016, the USA Operations volumes were higher primarily due to successful drilling programs in Permian and Eagle Ford, partially offset by natural declines in Other Upstream Operations.

In the second quarter and first six months of 2016, the Canadian Operations volumes were higher primarily due to successful drilling programs in Duvernay and Montney, partially offset by natural declines on Montney oil wells and the sale of certain assets in Wheatland in January 2015.

Results of Operations

Canadian Operations

Production Volumes

	Three months ended June 30					
	Natural Gas (MMcf/d)		**Oil & NGLs** (Mbbls/d)		**Total** (MBOE/d)	
	2016	2015	**2016**	2015	**2016**	2015
Production Volumes – After Royalties	**971**	881	**30.4**	26.3	**192.2**	173.2

Revenues, Net of Royalties

	Three months ended June 30							
	Natural Gas				**Oil & NGLs**			
	($ millions)		($/Mcf)		($ millions)		($/bbl)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 103**	$ 193	**$ 1.18**	$ 2.39	**$ 93**	$ 91	**$ 33.40**	$ 38.57
Realized Financial Hedging Gain (Loss)	**47**	106	**0.53**	1.32	**8**	(5)	**2.72**	(2.21)
Revenues, Net of Royalties	**$ 150**	$ 299	**$ 1.71**	$ 3.71	**$ 101**	$ 86	**$ 36.12**	$ 36.36

Operating Results (1)

	Three months ended June 30			
	Operating Cash Flow (2) ($ millions)		**Operating Netback** (3) ($/BOE)	
	2016	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 197**	$ 286	**$ 11.23**	$ 18.05
Realized Financial Hedging Gain	**55**	101	**3.12**	6.39
Revenues, Net of Royalties	**252**	387	**14.35**	24.44
Expenses				
Production, mineral and other taxes	**6**	8	**0.36**	0.45
Transportation and processing	**155**	170	**8.85**	10.77
Operating	**37**	38	**2.08**	2.43
Operating Cash Flow/Netback	**$ 54**	$ 171	**$ 3.06**	$ 10.79

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for the three months ended June 30, 2015 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in either transportation and processing expense or operating expense. As a result, for the three months ended June 30, 2015, the Canadian Operations has reclassified $1 million from transportation and processing expense and $7 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

Three months ended June 30, 2016 versus June 30, 2015

Operating Cash Flow of $54 million decreased $117 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $110 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $12 million.
- Average natural gas production volumes of 971 MMcf/d were higher by 90 MMcf/d, which increased revenues $20 million. Average oil and NGL production volumes of 30.4 Mbbls/d were higher by 4.1 Mbbls/d, which increased revenues $14 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $55 million compared to $101 million in 2015.
- Transportation and processing expense decreased $15 million primarily due to the expiration of certain contracts, lower activity in Other Upstream Operations and the lower U.S./Canadian dollar exchange rate, partially offset by higher liquids processing fees in Montney and Duvernay.

Production Volumes

	Six months ended June 30					
	Natural Gas (MMcf/d)		**Oil & NGLs** (Mbbls/d)		**Total** (MBOE/d)	
	2016	2015	**2016**	2015	**2016**	2015
Production Volumes – After Royalties	**1,018**	1,004	**30.3**	27.0	**200.0**	194.4

Revenues, Net of Royalties

	Six months ended June 30							
	Natural Gas				**Oil & NGLs**			
	($ millions)		($/Mcf)		($ millions)		($/bbl)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 265**	$ 589	**$ 1.43**	$ 3.23	**$ 155**	$ 168	**$ 28.13**	$ 34.53
Realized Financial Hedging Gain (Loss)	**93**	260	**0.50**	1.43	**29**	(3)	**5.21**	(0.68)
Revenues, Net of Royalties	**$ 358**	$ 849	**$ 1.93**	$ 4.66	**$ 184**	$ 165	**$ 33.34**	$ 33.85

Operating Results (1)

	Six months ended June 30			
	Operating Cash Flow (2) ($ millions)		**Operating Netback** (3) ($/BOE)	
	2016	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 424**	$ 762	**$ 11.55**	$ 21.50
Realized Financial Hedging Gain	**122**	257	**3.35**	7.30
Revenues, Net of Royalties	**546**	1,019	**14.90**	28.80
Expenses				
Production, mineral and other taxes	**12**	16	**0.33**	0.46
Transportation and processing	**304**	345	**8.34**	9.80
Operating	**77**	74	**2.06**	2.09
Operating Cash Flow/Netback	**$ 153**	$ 584	**$ 4.17**	$ 16.45

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for the six months ended June 30, 2015 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in either transportation and processing expense or operating expense. As a result, for the six months ended June 30, 2015, the Canadian Operations has reclassified $3 million from transportation and processing expense and $13 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

Six months ended June 30, 2016 versus June 30, 2015

Operating Cash Flow of $153 million decreased $431 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $335 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $34 million.
- Average natural gas production volumes of 1,018 MMcf/d were higher by 14 MMcf/d, which increased revenues $11 million. Average oil and NGL production volumes of 30.3 Mbbls/d were higher by 3.3 Mbbls/d, which increased revenues $21 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $122 million compared to $257 million in 2015.
- Transportation and processing expense decreased $41 million primarily due to the expiration of certain contracts, the lower U.S./Canadian dollar exchange rate and lower activity in Other Upstream Operations, partially offset by higher liquids processing fees in Montney and Duvernay, and higher natural gas volumes and gathering and processing fees in Montney.

Other Expenses

	Three months ended June 30		Six months ended June 30	
($ millions, except as indicated)	**2016**	2015	**2016**	2015
Depreciation, depletion & amortization	**$ 67**	$ 68	**$ 149**	$ 173
Depletion rate ($/BOE)	**3.87**	4.31	**4.10**	4.91
Impairments	**226**	-	**493**	-

DD&A decreased in the second quarter and first six months of 2016 compared to 2015 primarily due to a lower depletion rate and the lower U.S./Canadian dollar exchange rate, partially offset by higher production volumes. The depletion rate was primarily impacted by the sales of certain assets in Wheatland and certain natural gas gathering and compression assets in Montney in the first quarter of 2015, the impact of a ceiling test impairment recognized in the first quarter of 2016 and the lower U.S./Canadian dollar exchange rate.

In the second quarter and first six months of 2016, the Canadian Operations recognized before-tax non-cash ceiling test impairments of $226 million and $493 million, respectively. The impairments primarily resulted from the decline in the 12-month average trailing prices, which reduced the Canadian 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.

	Natural Gas	**Oil & NGLs**
	AECO (C$/MMBtu)	Edmonton Light Sweet (C$/bbl)
12-Month Average Trailing Reserves Pricing [(1)]		
June 30, 2016	**2.14**	**52.46**
December 31, 2015	2.69	58.82
June 30, 2015	3.32	75.58

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

USA Operations

Production Volumes

	Three months ended June 30					
	Natural Gas (MMcf/d)		**Oil & NGLs** (Mbbls/d)		**Total** (MBOE/d)	
	2016	2015	**2016**	2015	**2016**	2015
Production Volumes – After Royalties	**447**	687	**101.6**	101.0	**176.1**	215.5

Revenues, Net of Royalties

	Three months ended June 30							
	Natural Gas				**Oil & NGLs**			
	($ millions)		($/Mcf)		($ millions)		($/bbl)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 70**	$ 146	**$ 1.74**	$ 2.33	**$ 312**	$ 414	**$ 33.76**	$ 45.21
Realized Financial Hedging Gain	**19**	58	**0.47**	0.93	**50**	5	**5.43**	0.52
Revenues, Net of Royalties	**$ 89**	$ 204	**$ 2.21**	$ 3.26	**$ 362**	$ 419	**$ 39.19**	$ 45.73

Operating Results (1)

	Three months ended June 30			
	Operating Cash Flow (2) ($ millions)		**Operating Netback** (3) ($/BOE)	
	2016	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 389**	$ 566	**$ 23.89**	$ 28.61
Realized Financial Hedging Gain	**71**	63	**4.32**	3.22
Revenues, Net of Royalties	**460**	629	**28.21**	31.83
Expenses				
Production, mineral and other taxes	**24**	30	**1.48**	1.53
Transportation and processing	**73**	144	**4.56**	7.34
Operating	**87**	147	**5.34**	7.46
Operating Cash Flow/Netback	**$ 276**	$ 308	**$ 16.83**	$ 15.50

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for the three months ended June 30, 2015 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in operating expense. As a result, for the three months ended June 30, 2015, the USA Operations has reclassified $4 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

Three months ended June 30, 2016 versus June 30, 2015

Operating Cash Flow of $276 million decreased $32 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $25 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $105 million.
- Average natural gas production volumes of 447 MMcf/d were lower by 240 MMcf/d, which decreased revenues $51 million. Average oil and NGL production volumes of 101.6 Mbbls/d were higher by 0.6 Mbbls/d, which increased revenues $3 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $71 million compared to $63 million in 2015.
- Production, mineral and other taxes decreased $6 million primarily due to lower pricing and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Transportation and processing expense decreased $71 million primarily due to the expiration and renegotiation of certain transportation contracts and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Operating expense decreased $60 million primarily due to lower activity, cost-saving initiatives and the sale of Haynesville natural gas assets in the fourth quarter of 2015.

Production Volumes

	Six months ended June 30					
	Natural Gas (MMcf/d)		**Oil & NGLs** (Mbbls/d)		**Total** (MBOE/d)	
	2016	2015	**2016**	2015	**2016**	2015
Production Volumes – After Royalties	**448**	708	**101.1**	97.0	**175.8**	214.9

Revenues, Net of Royalties

	Six months ended June 30							
	Natural Gas				**Oil & NGLs**			
	($ millions)		($/Mcf)		($ millions)		($/bbl)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 148**	$ 341	**$ 1.81**	$ 2.66	**$ 529**	$ 709	**$ 28.77**	$ 40.43
Realized Financial Hedging Gain	**35**	112	**0.43**	0.88	**143**	43	**7.76**	2.45
Revenues, Net of Royalties	**$ 183**	$ 453	**$ 2.24**	$ 3.54	**$ 672**	$ 752	**$ 36.53**	$ 42.88

Operating Results [(1)]

	Six months ended June 30			
	Operating Cash Flow [(2)] ($ millions)		**Operating Netback** [(3)] ($/BOE)	
	2016	2015	**2016**	2015
Revenues, Net of Royalties, excluding Hedging	**$ 688**	$ 1,062	**$ 21.16**	$ 26.99
Realized Financial Hedging Gain	**181**	155	**5.56**	3.99
Revenues, Net of Royalties	**869**	1,217	**26.72**	30.98
Expenses				
Production, mineral and other taxes	**41**	59	**1.27**	1.51
Transportation and processing	**171**	299	**5.34**	7.68
Operating	**200**	262	**6.20**	6.69
Operating Cash Flow/Netback	**$ 457**	$ 597	**$ 13.91**	$ 15.10

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for the six months ended June 30, 2015 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in operating expense. As a result, for the six months ended June 30, 2015, the USA Operations has reclassified $14 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

Six months ended June 30, 2016 versus June 30, 2015

Operating Cash Flow of $457 million decreased $140 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $69 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $214 million.
- Average natural gas production volumes of 448 MMcf/d were lower by 260 MMcf/d, which decreased revenues $124 million. Average oil and NGL production volumes of 101.1 Mbbls/d were higher by 4.1 Mbbls/d, which increased revenues $34 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $181 million compared to $155 million in 2015.
- Production, mineral and other taxes decreased $18 million primarily due to lower pricing and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Transportation and processing expense decreased $128 million primarily due to the expiration and renegotiation of certain transportation contracts and the sale of Haynesville natural gas assets in the fourth quarter of 2015.
- Operating expense decreased $62 million primarily due to cost-saving initiatives, lower activity and the sale of Haynesville natural gas assets in the fourth quarter of 2015.

Other Expenses

	Three months ended June 30		Six months ended June 30	
($ millions, except as indicated)	**2016**	2015	**2016**	2015
Depreciation, depletion & amortization	**$ 143**	$ 301	**$ 302**	$ 637
Depletion rate ($/BOE)	**8.90**	15.18	**9.44**	16.07
Impairments	**258**	2,081	**903**	3,997

DD&A decreased in the second quarter and first six months of 2016 compared to 2015 primarily due to a lower depletion rate and lower production volumes. The depletion rate was lower primarily due to the impact of ceiling test impairments recognized in 2015 and the first quarter of 2016 and the sale of Haynesville natural gas assets in the fourth quarter of 2015.

In the second quarter and first six months of 2016, the USA Operations recognized before-tax non-cash ceiling test impairments of $258 million and $903 million, respectively compared to $2,081 million and $3,997 million, respectively, in 2015. The impairments primarily resulted from the decline in the 12-month average trailing prices, which reduced the 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.

	Natural Gas	**Oil & NGLs**
	Henry Hub ($/MMBtu)	WTI ($/bbl)
12-Month Average Trailing Reserves Pricing (1)		
June 30, 2016	**2.24**	**43.12**
December 31, 2015	2.58	50.28
June 30, 2015	3.38	71.68

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

Market Optimization

	Three months ended June 30		Six months ended June 30	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**$ 92**	$ 88	**$ 179**	$ 227
Expenses				
Transportation and processing	**22**	-	**43**	-
Operating	**6**	8	**14**	24
Purchased product	**79**	79	**152**	200
	$ (15)	$ 1	**$ (30)**	$ 3

Market Optimization revenues and purchased product expense relate to activities that provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification. Revenues and purchased product expense decreased in the six months ended June 30, 2016 compared to 2015 primarily due to lower commodity prices offset by higher third-party volumes for optimization activity. Transportation and processing relates to downstream transportation contracts and commitments resulting from certain property divestitures.

Corporate and Other

	Three months ended June 30		Six months ended June 30	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**$ (440)**	$ (274)	**$ (477)**	$ (384)
Expenses				
Transportation and processing	**(6)**	(15)	**(5)**	(7)
Operating	**5**	5	**10**	11
Depreciation, depletion and amortization	**20**	25	**40**	50
	$ (459)	$ (289)	**$ (522)**	$ (438)

Revenues mainly includes unrealized hedging gains or losses recorded on derivative financial contracts which result from the volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. Transportation and processing expense reflects unrealized financial hedging gains or losses related to the Company’s power financial derivative contracts. DD&A includes amortization of corporate assets, such as computer equipment, office buildings, furniture and leasehold improvements.

Corporate and Other results include revenues and operating expenses related to the sublease of office space in The Bow office building. Further information on The Bow office sublease can be found in Note 10 to the Interim Condensed Consolidated Financial Statements.

Other Operating Results

Expenses

($ millions)	Three months ended June 30 2016	Three months ended June 30 2015	Six months ended June 30 2016	Six months ended June 30 2015
Accretion of asset retirement obligation	**$ 13**	$ 11	**$ 26**	$ 23
Administrative	**61**	84	**140**	156
Interest	**107**	278	**210**	403
Foreign exchange (gain) loss, net	**23**	(86)	**(356)**	570
(Gain) loss on divestitures	**2**	(2)	**2**	(16)
Other	**24**	4	**(63)**	5
	$ 230	$ 289	**$ (41)**	$ 1,141

Administrative expense in the first six months of 2016 decreased from 2015 primarily due to lower salaries and benefits as a result of a lower headcount, a provision for a well control incident in the second quarter of 2015, the lower U.S./Canadian dollar exchange rate and lower office costs, partially offset by higher long-term compensation costs due to the increase in the Encana share price in the second quarter of 2016. Administrative expense in the second quarter of 2016 compared to 2015 was impacted by the items discussed above as well as lower restructuring costs of $16 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 current low commodity price environment. Encana incurred restructuring costs of $31 million during the first six months of 2016 and 2015.

Interest expense in the second quarter of 2016 decreased 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. Interest expense in the first six months of 2016 decreased from 2015 primarily due to the one-time payment associated with the redemptions as discussed above 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 gains and losses result from the impact of the fluctuations in the Canadian to U.S. dollar exchange rate. In the second quarter of 2016, Encana recorded foreign exchange losses on the translation of U.S. dollar long-term debt issued from Canada and the translation of intercompany notes compared to foreign exchange gains in 2015, partially offset by foreign exchange gains on settlements in the second quarter of 2016 compared to foreign exchange losses in 2015. In the first six months of 2016, Encana recorded foreign exchange gains on the translation of U.S. dollar long-term debt issued from Canada and on settlements compared to foreign exchange losses in 2015.

Gain on divestitures in the first six months of 2015 primarily includes a before tax gain on the sale of the Encana Place office building in Calgary.

Other in the first six months of 2016 primarily includes a before tax gain of $89 million on the early retirement of long-term debt as discussed in the Capital Resources and Liquidity section of this MD&A, partially offset by a one-time third party payment relating to a previously divested asset.

Income Tax

($ millions)	Three months ended June 30 **2016**	2015	Six months ended June 30 **2016**	2015
Current Income Tax (Recovery)	**$ (12)**	$ (35)	**$ (9)**	$ (19)
Deferred Income Tax (Recovery)	**(455)**	(903)	**(759)**	(1,866)
Income Tax Expense (Recovery)	**$ (467)**	$ (938)	**$ (768)**	$ (1,885)

Total income tax recovery of $768 million in the first six months of 2016 was lower than 2015 primarily due to changes in net earnings (loss) before tax, mainly resulting from lower non-cash ceiling test impairments, and changes in the estimated annual effective income tax rate. The net earnings variances are discussed in the Financial Results section of this MD&A.

Encana's interim income tax expense is determined using the estimated annual effective income tax rate applied to year-to-date net earnings before 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.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its Subsidiaries operate are subject to change. As a result, there are tax matters under review. The Company believes that the provision for taxes is adequate.

Liquidity and Capital Resources

($ millions)	Three months ended June 30 **2016**	2015	Six months ended June 30 **2016**	2015
Net Cash From (Used In)				
Operating activities	**$ 83**	$ 298	**$ 240**	$ 780
Investing activities	**(272)**	(681)	**(614)**	(413)
Financing activities	**260**	(1,170)	**387**	(202)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**-**	19	**9**	(7)
Increase (Decrease) in Cash and Cash Equivalents	**$ 71**	$ (1,534)	**$ 22**	$ 158
Cash and Cash Equivalents, End of Period	**$ 293**	$ 496	**$ 293**	$ 496

Operating Activities

Net cash from operating activities in the second quarter of 2016 of $83 million decreased $215 million from 2015 primarily due to net changes in non-cash working capital. In the second quarter of 2016, the net change in non-cash working capital was a deficit of $94 million compared to a surplus of $110 million in 2015.

Net cash from operating activities in the first six months of 2016 of $240 million decreased $540 million from 2015. These changes are primarily a result of the Cash Flow variances discussed in the Financial Results section of this MD&A and net changes in non-cash working capital. In the first six months of 2016, the net change in non-cash working capital was a deficit of $35 million compared to a surplus of $104 million in 2015.

The Company had a working capital deficit of $99 million at June 30, 2016 compared to a surplus of $274 million at December 31, 2015. The decrease in working capital is primarily due to a decrease in risk management assets and an increase in risk management liabilities, partially offset by a decrease in accounts payable and accrued liabilities. At June 30, 2016, working capital included cash and cash equivalents of $293 million compared to $271 million at

December 31, 2015. Encana expects it will continue to meet the payment terms of its suppliers. The current working capital deficit is expected to improve upon receipt of proceeds from announced divestitures. Encana's primary sources of liquidity are discussed in the Financing Activities section of this MD&A.

Investing Activities

Net cash used in investing activities in the first six months of 2016 was $614 million compared to $413 million in 2015. The change was primarily due to lower proceeds from divestitures and lower cash in reserve released from escrow, partially offset by lower capital expenditures. Further information on capital expenditures and divestitures can be found in the Net Capital Investment section of this MD&A.

Financing Activities

Net cash from financing activities in the first six months of 2016 was $387 million compared to net cash used of $202 million in 2015. The change was primarily due to proceeds of $1,088 million from the issuance of common shares in the first quarter of 2015, partially offset by a lower repayment of long-term debt in 2016 and a higher net issuance of revolving long-term debt compared to 2015.

Credit Facilities

The following table outlines the Company's committed revolving bank credit facilities at June 30, 2016:

($ billions)	Capacity	Unused	Maturity Date
Committed Revolving Bank Credit Facilities			
Encana Credit Facility	**3.0**	**1.5**	**July 2020**
U.S. Subsidiary Credit Facility	**1.5**	**1.5**	**July 2020**

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under its credit facility agreements. Management monitors Debt to Adjusted Capitalization as a proxy for Encana's financial covenant under its credit facility agreements, 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. Debt to Adjusted Capitalization was 31 percent at June 30, 2016 and 28 percent at December 31, 2015.

During the first quarter of 2016, Encana received a downgrade in its credit rating by Moody's Investors Service, along with confirmed investment grade credit ratings by Standard & Poor's Ratings Services, DBRS Limited and Fitch Ratings, Inc. As a result of the split ratings, the Company no longer has access to its U.S. Commercial Paper program and there was a nominal increase in the cost of short-term borrowings on the Company's credit facilities. The Company continues to have full access to its $4.5 billion committed revolving bank credit facilities of which $3.0 billion remained unused at June 30, 2016. The facilities remain committed through July 2020. The split ratings have not impacted the Company's ability to fund its operations, development activities or capital program. For further information on credit ratings, refer to the Company's AIF.

Long-Term Debt

Encana's long-term debt totaled $5,690 million at June 30, 2016 and $5,333 million at December 31, 2015. There was no current portion of long-term debt outstanding at June 30, 2016 or December 31, 2015. The long-term debt balances reflect Encana's January 1, 2016 retrospective adoption of accounting standards update ("ASU") 2015-03, *Simplifying the Presentation of Debt Issuance Costs,* as described in the Accounting Policies and Estimates section of this MD&A.

On March 16, 2016, Encana announced Tender Offers for certain of the Company's outstanding Notes. The announced 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 expenses in the Interim Condensed Consolidated Statement of Earnings.

At June 30, 2016, Encana had an outstanding balance of $1,493 million under the Company’s revolving credit facility, which reflected principal obligations related to LIBOR loans maturing at various dates with a weighted average interest rate of 2.38 percent. A portion of the outstanding balance represents amounts drawn to fund the Tender Offers. The LIBOR loans are fully supported and Management expects they will continue to be supported by the revolving credit facility which matures in July 2020. At December 31, 2015, Encana had an outstanding balance of $210 million under the Company’s revolving credit facility which reflected principal obligations related to LIBOR loans maturing at various dates with a weighted average interest rate of 1.87 percent. At December 31, 2015, Encana also had an outstanding balance under the Company’s revolving credit facility of $440 million which reflected U.S. Commercial Paper issuances maturing at various dates with a weighted average interest rate of 1.13 percent.

Encana has the flexibility to refinance maturing long-term debt or repay debt maturities from existing sources of liquidity. Encana’s primary sources of liquidity include cash and cash equivalents, revolving bank credit facilities, operating cash flow and proceeds from asset divestitures.

Shelf Prospectus

Encana has in place a short form base debt shelf prospectus whereby the Company may issue from time to time up to $6.0 billion, or the equivalent in foreign currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants and units in Canada and/or the U.S. During 2015, the Company filed a prospectus supplement to the base shelf prospectus 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). At June 30, 2016, $4.9 billion, or the equivalent in foreign currencies, remained accessible under the shelf prospectus, the availability of which is dependent upon certain eligibility requirements and market conditions. The shelf prospectus expires on July 26, 2016 and will be renewed.

Outstanding Share Data

(millions)	**June 30, 2016**	December 31, 2015
Common Shares Outstanding [1]	**849.9**	849.8
Stock Options with TSARs attached [1], [2]		
Outstanding	**19.5**	18.3
Exercisable	**11.4**	10.0

(1) As at July 15, 2016, the number of common shares outstanding and stock options with Tandem Stock Appreciation Rights ("TSARs") attached remains unchanged from June 30, 2016.
(2) A TSAR gives 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.

During the first six months of 2016, Encana issued 86,848 common shares under the Company's dividend reinvestment plan ("DRIP") compared with 2,872,237 common shares in 2015. The number of common shares issued under the DRIP decreased in 2016 primarily as a result of the lower dividend paid per share in the first six months of 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 will be issued from its treasury without a discount to the average market price of the common shares.

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board.

	Three months ended June 30		Six months ended June 30	
($ millions, except as indicated)	**2016**	2015	**2016**	2015
Dividend Payments	**$ 12**	$ 55	**$ 25**	$ 107
Dividend Payments ($/share)	**0.015**	0.07	**0.03**	0.14

The dividends paid in the second quarter and first six months of 2016 included $0.3 million and $0.6 million, respectively, in common shares issued in lieu of cash dividends under the DRIP compared to $18 million and $32 million, respectively, for 2015.

On July 20, 2016, the Board declared a dividend of $0.015 per share payable on September 30, 2016 to common shareholders of record as of September 15, 2016.

Capital Structure

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 long-standing practice of maintaining capital discipline and managing and adjusting its capital structure according to market conditions to maintain flexibility while achieving the Company's objectives.

To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt. In managing its capital structure, the Company monitors the following non-GAAP financial metrics as indicators of its overall financial strength, which are defined in the Non-GAAP Measures section of this MD&A.

	June 30, 2016	December 31, 2015
Debt to Debt Adjusted Cash Flow	**4.2x**	2.8x
Debt to Adjusted Capitalization	**31%**	28%

Commitments and Contingencies

Commitments

The following table outlines the Company's commitments at June 30, 2016:

	Expected Future Payments						
($ millions, undiscounted)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation and Processing	$ 257	$ 569	$ 580	$ 652	$ 626	$ 3,136	**$ 5,820**
Drilling and Field Services	74	115	67	30	15	4	**305**
Operating Leases	14	25	24	11	3	19	**96**
Commitments	$ 345	$ 709	$ 671	$ 693	$ 644	$ 3,159	**$ 6,221**

Included in Transportation and Processing in the table above are certain commitments associated with midstream service agreements with VMLP. Additional information can be found in Note 14 to the Interim Condensed Consolidated Financial Statements. Encana also has significant development commitments with joint venture partners, a portion of which may be satisfied by the Drilling and Field Services commitments included in the table above.

Further to the Commitments disclosed above, Encana also has obligations related to its risk management program and to fund its defined benefit pension and other post-employment benefit plans. Contractual obligations arising from long-term debt, asset retirement obligations, The Bow office building and capital leases are recognized on the Company's balance sheet. Additional information can be found in the note disclosures to the Interim Condensed Consolidated Financial Statements.

Divestiture transactions can reduce certain commitments and obligations disclosed above. The Company expects to fund its 2016 commitments and obligations from Cash Flow and cash and cash equivalents.

Contingencies

Encana is involved in various legal claims and actions arising in the 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 adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Risk Management

Encana's business, prospects, financial condition, results of operations and cash flows, and in some cases its reputation, are impacted by risks that can be categorized as follows:

- financial risks;
- operational risks; and
- environmental, regulatory, reputational and safety risks.

Encana aims to strengthen its position as a leading North American energy producer and grow shareholder value through a disciplined focus on generating profitable growth. Encana continues to focus on developing a balanced portfolio of low-risk and low-cost long-life plays, enabling the Company to respond to market uncertainties. Management adjusts financial and operational risk strategies to proactively respond to changing economic conditions and to mitigate or reduce risk.

Issues that can affect Encana's reputation are generally strategic or emerging issues that can be identified early and then appropriately managed, but can also include unforeseen issues that must be managed on a more urgent basis. Encana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established appropriate policies, procedures, guidelines and responsibilities for identifying and managing these risks.

Financial Risks

Encana defines financial risks as the risk of loss or lost opportunity resulting from financial management and market conditions that could have an impact on Encana's business.

Financial risks include, but are not limited to:

- market pricing of natural gas and liquids;
- credit and liquidity;
- foreign exchange rates; and
- interest rates.

Encana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative financial instruments is governed under formal policies and is subject to limits established by the Board. All derivative financial agreements are with major global financial institutions or with corporate counterparties having investment grade credit ratings. Encana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use to the mitigation of financial risk in order to support capital plans and strategic objectives.

To partially mitigate commodity price risk, the Company may enter into transactions that fix, set a floor or combine to set floors and caps on price exposures. To help protect against regional price differentials, Encana executes transactions to manage the price differentials between its production areas and various sales points. Further information, including the details of Encana's financial instruments as at June 30, 2016, is disclosed in Note 19 to the Interim Condensed Consolidated Financial Statements.

Counterparty credit risks are regularly and proactively managed. A substantial portion of Encana's credit exposure is with customers in the oil and gas industry or financial institutions. Credit exposures are managed through the use of Board-approved credit policies governing the Company's credit portfolio, including credit practices that limit transactions and grant payment terms according to industry standards and counterparties' credit quality.

The Company manages liquidity risk using cash and debt management programs. The Company has access to 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 Company's ability to access cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. The Company minimizes its liquidity risk by managing its capital structure which may include adjusting capital spending, adjusting dividends paid to shareholders, issuing new shares, issuing new debt or repaying existing debt.

Operational Risks

Operational risks are defined as the risk of loss or lost opportunity resulting from the following:

- operating activities;
- capital activities, including the ability to complete projects; and
- reserves and resources replacement.

The Company's ability to operate, generate cash flows, complete projects, and value reserves and resources is subject to financial risks, including commodity price volatility mentioned above, continued market demand for its products and other factors outside of its control. These factors include: general business and market conditions; economic recessions and financial market turmoil; the overall state of the capital markets, including investor appetite for investments in the oil and gas industry generally and the Company's securities in particular; the ability to secure and maintain cost-effective financing for its commitments; legislative, environmental and regulatory matters; unexpected cost increases; royalties; taxes; partner funding for their share of joint venture and partnership commitments; the availability of drilling and other equipment; the ability to retain leases and access lands; the ability to access water for hydraulic fracturing operations; weather; the availability and proximity of processing and pipeline capacity; transportation interruption and constraints; technology failures; the ability to assess and integrate new assets; cyber security breaches; accidents; the availability and ability to attract qualified personnel and service providers; type curve performance; and reservoir quality. If Encana fails to acquire or find additional natural gas and liquids reserves and resources, its reserves, resources and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and resources and acquiring, discovering or developing additional reserves and resources. To mitigate these risks, as part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk, engineering risk and reliance on third party service providers.

When making operating and investing decisions, Encana's highly disciplined, dynamic and centrally controlled capital allocation program ensures investment dollars are directed in a manner that is consistent with the Company's strategy. Encana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

In January 2016, the Alberta Government released the Modernized Royalty Framework ("MRF") outlining changes to the province's royalty structure. The MRF will result in the modernization and simplification of the royalty structure with changes to the royalty framework for crude oil, liquids and natural gas applying to new wells drilled after January 1, 2017 and existing royalties remaining in effect for 10 years on wells drilled (spud) before 2017. The Company continues to assess the impact of the changes to the royalty structure and believes the MRF will not have a negative impact on its operations.

Environmental, Regulatory, Reputational and Safety Risks

The Company is committed to safety in its operations and has high regard for the environment and stakeholders, including the public and regulators. The Company's business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas, oil and NGLs and the operation of midstream facilities. When assessing the materiality of environmental risk factors, Encana takes into account a number of qualitative and quantitative factors, including, but not limited to, the financial, operational, reputational and regulatory aspects of each identified risk factor. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, Encana maintains a system that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to the Executive Leadership Team and the Board. The Corporate Responsibility, Environment, Health and Safety Committee of Encana's Board provides recommended environmental policies for approval by Encana's Board 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 audits, are designed to provide assurance that environmental and regulatory standards are met. Emergency response plans are in place to provide guidance during times of crisis. Contingency plans are in place for a timely response to environmental events and remediation/reclamation strategies are utilized to restore the environment.

Encana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion, including hydraulic fracturing and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Changes in government regulation could impact the Company's existing and planned projects as well as impose a cost of compliance.

In the state of Colorado, several cities have passed local ordinances limiting or banning certain oil and gas activities, including hydraulic fracturing. These local rule-making initiatives have not significantly impacted the Company's operations or development plans in the state to date. Encana continues to work with state and local governments, academics and industry leaders to respond to hydraulic fracturing related concerns in Colorado. The Company recognizes that additional hydraulic fracturing ballot and/or local rule-making limiting or restricting oil and gas development activities are a possibility in the future and will continue to monitor and respond to these developments in 2016.

In Canada, the federal government and several provincial governments, including Alberta and British Columbia, have announced an enhanced focus on climate change policy in 2016. Encana continues to monitor developments, engage in consultations as appropriate and is actively managing the implementation of new climate-related policy and regulations in order minimize the potential impact on its business.

In the U.S., the federal government has noted climate change action as a priority for the current administration and the Environmental Protection Agency has outlined a series of steps to address methane and volatile organic compound emissions from the oil and gas industry, including a new goal to reduce oil and gas methane emissions by 40 to 45 percent from 2012 levels by 2025. The reductions will be achieved through proposed regulatory and voluntary measures. Encana continues to monitor these developments, provide comment as appropriate and assess the potential impact on its business.

A comprehensive discussion of Encana's risk management is provided in the Company's annual MD&A for the year ended December 31, 2015.

Accounting Policies and Estimates

Critical Accounting Estimates

Refer to the annual MD&A for the year ended December 31, 2015 for a comprehensive discussion of Encana's Critical Accounting Policies and Estimates.

Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2016, Encana adopted the following ASUs issued by the Financial Accounting Standards Board ("FASB") which have not had a material impact on the Company's Interim Condensed Consolidated Financial Statements:

- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period*. The update requires that a performance target that affects vesting and could be achieved after the requisite service period be treated as a performance condition. The amendments have been applied prospectively.

- ASU 2015-02, *Amendments to the Consolidation Analysis*. The update requires limited partnerships and similar entities to be evaluated under the variable interest and voting interest models, eliminate the presumption that a general partner should consolidate a limited partnership, and simplify the identification of variable interests and related effect on the primary beneficiary criterion when fees are paid to a decision maker. The amendments have been applied using a full retrospective approach.
- ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. The updates require debt issuance costs to be presented on the balance sheet as a deduction from the carrying amount of the related liability. Previously, debt issuance costs were presented as a deferred charge within assets. The updates further clarify that regardless of whether there are outstanding borrowings, debt issuance costs arising from credit arrangements can be presented as an asset and subsequently amortized ratably over the term of the arrangement. These amendments have been applied retrospectively and resulted in a $30 million decrease in Other Assets, with a corresponding $30 million decrease in Long-Term Debt as at December 31, 2015.

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, which replaces Topic 605, *Revenue Recognition*, and other industry-specific guidance in the Accounting Standards Codification ("ASC"). 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, but permits early adoption using the original effective date of January 1, 2017. The standard can be applied using one of two retrospective application methods at the date of adoption. Encana is currently assessing the potential impact of the standard on the Company's Consolidated Financial Statements.

As of January 1, 2019, Encana will be required to adopt ASU 2016-02, *Leases* under Topic 842, which replaces 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 requiring leases recognized to be classified as either finance or operating leases was retained for the purpose of subsequent measurement and presentation 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 and provides for certain practical expedients. Encana is currently assessing the standard, and expects the new standard will have a material impact on the Company's Consolidated Financial Statements.

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. 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: Cash Flow; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; and Debt to Adjusted Capitalization. Management's use of these measures is discussed further below.

Cash Flow and Free Cash Flow

Cash Flow is a non-GAAP measure commonly used in the oil and gas industry and by Encana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets.

Free Cash Flow is a non-GAAP measure defined as Cash Flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.

	Six months ended June 30		2016		2015				2014	
($ millions)	**2016**	2015	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash From (Used in) Operating Activities	**$ 240**	$ 780	**$ 83**	$ 157	$ 448	$ 453	$ 298	$ 482	$ 261	$ 696
(Add back) deduct:										
Net change in other assets and liabilities	**(9)**	-	**(5)**	(4)	7	(18)	7	(7)	(15)	(11)
Net change in non-cash working capital	**(35)**	104	**(94)**	59	58	100	110	(6)	(141)	155
Cash tax on sale of assets	**-**	-	**-**	-	-	-	-	-	40	(255)
Cash Flow	**$ 284**	$ 676	**$ 182**	$ 102	$ 383	$ 371	$ 181	$ 495	$ 377	$ 807
Deduct:										
Capital investment	**574**	1,479	**215**	359	280	473	743	736	857	598
Free Cash Flow	**$ (290)**	$ (803)	**$ (33)**	$ (257)	$ 103	$ (102)	$ (562)	$ (241)	$ (480)	$ 209

Operating Earnings

Operating Earnings (Loss) is a non-GAAP measure that adjusts Net Earnings (Loss) Attributable to Common Shareholders by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. Operating Earnings (Loss) is commonly used in the oil and gas industry and by Encana to provide investors with information that is more comparable between periods.

Operating Earnings (Loss) is defined as Net Earnings (Loss) Attributable to Common Shareholders excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures, gains on debt retirement, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

	Six months ended June 30		2016		2015				2014	
($ millions)	**2016**	2015	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net Earnings (Loss) Attributable to Common Shareholders	**$ (980)**	$ (3,317)	**$ (601)**	$ (379)	$ (612)	$ (1,236)	$ (1,610)	$ (1,707)	$ 198	$ 2,807
After-tax (addition) / deduction:										
Unrealized hedging gain (loss)	**(345)**	(285)	**(310)**	(35)	(66)	107	(187)	(98)	341	160
Impairments	**(938)**	(2,550)	**(331)**	(607)	(514)	(1,066)	(1,328)	(1,222)	-	-
Restructuring charges (1)	**(22)**	(20)	**-**	(22)	(5)	(20)	(10)	(10)	(4)	(5)
Non-operating foreign exchange gain (loss)	**247**	(394)	**(48)**	295	(96)	(212)	114	(508)	(151)	(218)
Gain (loss) on divestitures	**(1)**	11	**(1)**	-	-	(2)	1	10	(11)	2,399
Gain on debt retirement	**65**	-	**-**	65	-	-	-	-	-	-
Income tax adjustments	**55**	69	**-**	55	(42)	(19)	(33)	102	(12)	190
Operating Earnings (Loss) (1)	**$ (41)**	$ (148)	**$ 89**	$ (130)	$ 111	$ (24)	$ (167)	$ 19	$ 35	$ 281

(1) In Q2 2015, organizational structure changes were formalized which resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.

Upstream Operating Cash Flow, excluding Hedging

Upstream Operating Cash Flow, excluding Hedging is a non-GAAP measure that adjusts the Canadian and USA Operations revenues, net of royalties for production, mineral and other taxes, transportation and processing expense, operating expense and the impacts of realized hedging. Management monitors Upstream Operating Cash Flow, excluding Hedging as it reflects operating performance and measures the amount of cash generated from the Company's upstream operations. Upstream Operating Cash Flow, excluding Hedging is reconciled to GAAP measures in the Results of Operations section of this MD&A. The table below totals Upstream Operating Cash Flow for Encana.

	Six months ended June 30		2016		2015				2014	
($ millions)	**2016**	2015	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Upstream Operating Cash Flow										
Canadian Operations	**$ 153**	$ 584	**$ 54**	$ 99	$ 204	$ 200	$ 171	$ 413	$ 341	$ 477
USA Operations	**457**	597	**276**	181	348	331	308	289	480	505
	$ 610	$ 1,181	**$ 330**	$ 280	$ 552	$ 531	$ 479	$ 702	$ 821	$ 982
(Add back) deduct:										
Realized Hedging Gain (Loss)										
Canadian Operations	**$ 122**	$ 257	**$ 55**	$ 67	$ 129	$ 109	$ 101	$ 156	$ 49	$ 19
USA Operations	**181**	155	**71**	110	162	108	63	92	78	11
	$ 303	$ 412	**$ 126**	$ 177	$ 291	$ 217	$ 164	$ 248	$ 127	$ 30
Upstream Operating Cash Flow, excluding Hedging										
Canadian Operations	**$ 31**	$ 327	**$ (1)**	$ 32	$ 75	$ 91	$ 70	$ 257	$ 292	$ 458
USA Operations	**276**	442	**205**	71	186	223	245	197	402	494
	$ 307	$ 769	**$ 204**	$ 103	$ 261	$ 314	$ 315	$ 454	$ 694	$ 952

Operating Netback

Operating Netback is a common metric used in the oil and gas industry to measure operating performance. Operating Netbacks are calculated on a BOE basis by determining product revenues, net of royalties and deducting costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing expense and operating expense. The Operating Netback calculation is shown in the Results of Operations section of this MD&A.

Debt to Debt Adjusted Cash Flow

Debt to Debt Adjusted Cash Flow is a non-GAAP measure monitored by Management as an indicator of the Company's overall financial strength. Debt Adjusted Cash Flow is a non-GAAP measure defined as Cash Flow on a trailing 12-month basis excluding interest expense after tax.

($ millions)	**June 30, 2016**	December 31, 2015
Debt (1)	**$ 5,690**	$ 5,333
Cash Flow	**1,038**	1,430
Interest Expense, after tax	**308**	452
Debt Adjusted Cash Flow	**$ 1,346**	$ 1,882
Debt to Debt Adjusted Cash Flow	**4.2x**	2.8x

(1) 2015 has been restated due to the adoption of ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, as discussed in the Accounting Policies and Estimates section of this MD&A.

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 its credit facility agreements 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)	**June 30, 2016**	December 31, 2015
Debt (1)	**$ 5,690**	$ 5,333
Total Shareholders' Equity	**4,907**	6,167
Equity Adjustment for Impairments at December 31, 2011	**7,746**	7,746
Adjusted Capitalization	**$ 18,343**	$ 19,246
Debt to Adjusted Capitalization	**31%**	28%

(1) 2015 has been restated due to the adoption of ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, as discussed in the Accounting Policies and Estimates section of this MD&A.

Advisory

Forward-Looking Statements

This document contains certain forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements include:

- accelerated growth in the Core Four Assets
- anticipated Cash Flow
- anticipated cash and cash equivalents
- expected proceeds from announced divestitures, use of proceeds therefrom, satisfaction of closing conditions and regulatory approvals and timing of closing
- anticipated hedging and outcomes of risk management program
- lowering well costs and optimizing completions
- the projections and expectation of meeting the targets contained in the Company's 2016 corporate guidance
- growth in long-term shareholder value
- anticipated oil, natural gas and NGL prices
- anticipated future cost and operating efficiencies
- the Company's expectation to fund its 2016 commitments and obligations from Cash Flow and cash and cash equivalents
- managing risk, including the impact of changes to the royalty structure
- flexibility of capital spending plans
- estimates of reserves and resources
- expected production and product type
- level of expenditures and impact of environmental legislation and changes in laws or regulations
- financial flexibility and discipline, access to cash and cash equivalents and other methods of funding, the ability to meet financial obligations, manage debt and financial ratios, finance growth and compliance with financial covenants
- expectation that current working capital deficit will improve upon receipt of proceeds from announced divestitures
- impact to Encana as a result of a downgrade to its credit rating
- access to the Company's credit facility and shelf prospectus and expected renewal thereof
- the declaration and payment of future dividends, if any
- statements with respect to future ceiling test impairments
- the continued evolution of the Company's resource play hub model to drive greater productivity and cost efficiencies while reducing its environmental footprint
- statements with respect to its strategic objectives
- the adequacy of the Company's provision for taxes and legal claims
- anticipated proceeds and future benefits from various joint venture, partnership and other agreements
- 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:

- assumptions contained in the Company's current corporate guidance
- availability of attractive hedges and enforceability of risk management program
- effectiveness of the Company's resource play hub model to drive productivity and efficiencies
- results from innovations
- the expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements
- access to transportation and processing facilities where Encana operates
- enforceability of transaction agreements, the ability of the parties to satisfy closing conditions, the successful closing of, and the value of post- closing and other adjustments associated with announced divestitures and impact to expected proceeds
- 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, the benefits achieved and general industry expectations

Risks and uncertainties that may affect these business outcomes include: the ability to generate sufficient Cash Flow to meet the Company's obligations; risks inherent to closing announced divestitures on a timely basis or at all and adjustments that may reduce the expected proceeds and value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's Board to declare and pay dividends, if any; the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, including below an investment-grade credit rating, and its impact on access to capital markets and other sources of liquidity; fluctuations in currency and interest rates; assumptions based upon the Company's 2016 corporate guidance; failure to achieve anticipated results from 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 future lawsuits and regulatory actions made against the Company; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business as described from time to time in its most recent MD&A, financial statements, AIF and Form 40-F, as filed on SEDAR and EDGAR.

Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. The forward-looking statements contained in this document are made as of the date of this document and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by these cautionary statements.

Encana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that Encana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in Encana's news release dated July 21, 2016, which is available on Encana's website at www.encana.com, on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Oil and Gas Information

National Instrument 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. The Canadian protocol disclosure is contained in Appendix A and under “Narrative Description of the Business” in the AIF. In addition, certain disclosures have been prepared in accordance with U.S. disclosure requirements. The Company’s U.S. protocol disclosure is included in Note 27 (unaudited) to the Company’s Consolidated Financial Statements for the year ended December 31, 2015 and in Appendix D of the AIF.

A description of the primary differences between the disclosure requirements under the Canadian standards and under the U.S. standards is set forth under the heading “Reserves and Other Oil and Gas Information” in the AIF.

Natural Gas, Oil and NGLs Conversions

The conversion of natural gas volumes to BOE is on the basis of six thousand cubic feet to one barrel. 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. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

Play and Resource Play

Play is a term used by Encana which encompasses resource plays, geological formations and conventional plays. Resource play is a term used by Encana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

Additional Information

Further information regarding Encana Corporation, including its AIF, can be accessed under the Company’s public filings found on SEDAR at www.sedar.com, on EDGAR at www.sec.gov and on the Company’s website at www.encana.com.

Encana Corporation

Interim Condensed Consolidated Financial Statements
(unaudited)

For the period ended June 30, 2016

(U.S. Dollars)

Condensed Consolidated Statement of Earnings *(unaudited)*

($ millions, except per share amounts)		Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Revenues, Net of Royalties	*(Note 3)*	**$ 364**	$ 830	**$ 1,117**	$ 2,079
Expenses	*(Note 3)*				
Production, mineral and other taxes		**30**	38	**53**	75
Transportation and processing		**244**	299	**513**	637
Operating		**135**	198	**301**	371
Purchased product		**79**	79	**152**	200
Depreciation, depletion and amortization		**230**	394	**491**	860
Impairments	*(Note 8)*	**484**	2,081	**1,396**	3,997
Accretion of asset retirement obligation	*(Note 11)*	**13**	11	**26**	23
Administrative	*(Note 15)*	**61**	84	**140**	156
Interest	*(Note 5)*	**107**	278	**210**	403
Foreign exchange (gain) loss, net	*(Note 6)*	**23**	(86)	**(356)**	570
(Gain) loss on divestitures	*(Note 4)*	**2**	(2)	**2**	(16)
Other	*(Note 9)*	**24**	4	**(63)**	5
		1,432	3,378	**2,865**	7,281
Net Earnings (Loss) Before Income Tax		**(1,068)**	(2,548)	**(1,748)**	(5,202)
Income tax expense (recovery)	*(Note 7)*	**(467)**	(938)	**(768)**	(1,885)
Net Earnings (Loss)		**$ (601)**	$ (1,610)	**$ (980)**	$ (3,317)
Net Earnings (Loss) per Common Share					
Basic & Diluted	*(Note 12)*	**$ (0.71)**	$ (1.91)	**$ (1.15)**	$ (4.15)

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

($ millions)		Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net Earnings (Loss)		**$ (601)**	$ (1,610)	**$ (980)**	$ (3,317)
Other Comprehensive Income, Net of Tax					
Foreign currency translation adjustment	*(Note 13)*	**14**	(53)	**(256)**	425
Pension and other post-employment benefit plans	*(Notes 13, 17)*	**-**	-	**-**	1
Other Comprehensive Income (Loss)		**14**	(53)	**(256)**	426
Comprehensive Income (Loss)		**$ (587)**	$ (1,663)	**$ (1,236)**	$ (2,891)

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

($ millions)		**As at June 30, 2016**	As at December 31, 2015
Assets			
Current Assets			
Cash and cash equivalents		**$ 293**	$ 271
Accounts receivable and accrued revenues		**632**	645
Risk management	*(Notes 18, 19)*	**33**	367
Income tax receivable		**322**	324
		1,280	1,607
Property, Plant and Equipment, at cost:	*(Note 8)*		
Natural gas and oil properties, based on full cost accounting			
Proved properties		**42,392**	40,647
Unproved properties		**5,436**	5,616
Other		**2,285**	2,181
Property, plant and equipment		**50,113**	48,444
Less: Accumulated depreciation, depletion and amortization		**(41,421)**	(38,587)
Property, plant and equipment, net	*(Note 3)*	**8,692**	9,857
Cash in Reserve		**2**	2
Other Assets		**272**	266
Risk Management	*(Notes 18, 19)*	**-**	11
Deferred Income Taxes		**1,848**	1,081
Goodwill	*(Note 3)*	**2,832**	2,790
	(Note 3)	**$ 14,926**	$ 15,614
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,239**	$ 1,311
Income tax payable		**8**	6
Risk management	*(Notes 18, 19)*	**132**	16
		1,379	1,333
Long-Term Debt	*(Note 9)*	**5,690**	5,333
Other Liabilities and Provisions	*(Note 10)*	**2,062**	1,975
Risk Management	*(Notes 18, 19)*	**61**	9
Asset Retirement Obligation	*(Note 11)*	**801**	773
Deferred Income Taxes		**26**	24
		10,019	9,447
Commitments and Contingencies	*(Note 20)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares, without par value			
2016 issued and outstanding: 849.9 million shares (2015: 849.8 million shares)	*(Note 12)*	**3,622**	3,621
Paid in surplus		**1,358**	1,358
Retained earnings (Accumulated deficit)		**(1,207)**	(202)
Accumulated other comprehensive income	*(Note 13)*	**1,134**	1,390
Total Shareholders' Equity		**4,907**	6,167
		$ 14,926	$ 15,614

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Changes in Shareholders' Equity *(unaudited)*

Six Months Ended June 30, 2016 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings (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)		**-**	**-**	**(980)**	**-**	**(980)**
Dividends on Common Shares	*(Note 12)*	**-**	**-**	**(25)**	**-**	**(25)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 12)*	**1**	**-**	**-**	**-**	**1**
Other Comprehensive Income (Loss)	*(Note 13)*	**-**	**-**	**-**	**(256)**	**(256)**
Balance, June 30, 2016		**$ 3,622**	**$ 1,358**	**$ (1,207)**	**$ 1,134**	**$ 4,907**

Six Months Ended June 30, 2015 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2014		$ 2,450	$ 1,358	$ 5,188	$ 689	$ 9,685
Net Earnings (Loss)		-	-	(3,317)	-	(3,317)
Dividends on Common Shares	*(Note 12)*	-	-	(107)	-	(107)
Common Shares Issued	*(Note 12)*	1,098	-	-	-	1,098
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 12)*	32	-	-	-	32
Other Comprehensive Income	*(Note 13)*	-	-	-	426	426
Balance, June 30, 2015		$ 3,580	$ 1,358	$ 1,764	$ 1,115	$ 7,817

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Operating Activities					
Net earnings (loss)		**$ (601)**	$ (1,610)	**$ (980)**	$ (3,317)
Depreciation, depletion and amortization		**230**	394	**491**	860
Impairments	*(Note 8)*	**484**	2,081	**1,396**	3,997
Accretion of asset retirement obligation	*(Note 11)*	**13**	11	**26**	23
Deferred income taxes	*(Note 7)*	**(455)**	(903)	**(759)**	(1,866)
Unrealized (gain) loss on risk management	*(Note 19)*	**451**	278	**506**	414
Unrealized foreign exchange (gain) loss	*(Note 6)*	**73**	(245)	**(270)**	314
Foreign exchange on settlements	*(Note 6)*	**(53)**	137	**(85)**	235
(Gain) loss on divestitures	*(Note 4)*	**2**	(2)	**2**	(16)
Other		**38**	40	**(43)**	32
Net change in other assets and liabilities		**(5)**	7	**(9)**	-
Net change in non-cash working capital		**(94)**	110	**(35)**	104
Cash From (Used in) Operating Activities		**83**	298	**240**	780
Investing Activities					
Capital expenditures	*(Note 3)*	**(215)**	(743)	**(574)**	(1,479)
Acquisitions	*(Note 4)*	**(1)**	(3)	**(2)**	(38)
Proceeds from divestitures	*(Note 4)*	**-**	143	**6**	1,016
Cash in reserve		**-**	43	**-**	72
Net change in investments and other		**(56)**	(121)	**(44)**	16
Cash From (Used in) Investing Activities		**(272)**	(681)	**(614)**	(413)
Financing Activities					
Net issuance (repayment) of revolving long-term debt	*(Note 9)*	**288**	186	**843**	120
Repayment of long-term debt	*(Note 9)*	**-**	(1,302)	**(400)**	(1,302)
Issuance of common shares	*(Note 12)*	**-**	-	**-**	1,088
Dividends on common shares	*(Note 12)*	**(11)**	(37)	**(24)**	(75)
Capital lease payments and other financing arrangements	*(Note 10)*	**(17)**	(17)	**(32)**	(33)
Cash From (Used in) Financing Activities		**260**	(1,170)	**387**	(202)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**-**	19	**9**	(7)
Increase (Decrease) in Cash and Cash Equivalents		**71**	(1,534)	**22**	158
Cash and Cash Equivalents, Beginning of Period		**222**	2,030	**271**	338
Cash and Cash Equivalents, End of Period		**$ 293**	$ 496	**$ 293**	$ 496
Cash, End of Period		**$ 31**	$ 86	**$ 31**	$ 86
Cash Equivalents, End of Period		**262**	410	**262**	410
Cash and Cash Equivalents, End of Period		**$ 293**	$ 496	**$ 293**	$ 496

See accompanying Notes to Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. Basis of Presentation and Principles of Consolidation

Encana Corporation and its subsidiaries ("Encana" or "the Company") are in the business of the exploration for, the development of, and the production and marketing of natural gas, oil and natural gas liquids ("NGLs"). The term liquids is used to represent Encana's oil, NGLs and condensate.

The interim Condensed Consolidated Financial Statements include the accounts of Encana and are presented in accordance with accounting principles generally accepted in the United States ("U.S. GAAP").

The interim Condensed 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 natural gas and oil 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.

The interim Condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2015, except as noted below in Note 2. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, the interim Condensed Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2015.

These unaudited interim Condensed Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented. Interim condensed consolidated financial results are not necessarily indicative of consolidated financial results expected for the fiscal year.

2. Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2016, Encana adopted the following accounting standards updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"), which have not had a material impact on the Company's interim Condensed Consolidated Financial Statements:

- ASU 2014-12, "Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period". The update requires that a performance target that affects vesting and could be achieved after the requisite service period be treated as a performance condition. The amendments have been applied prospectively.

- ASU 2015-02, "Amendments to the Consolidation Analysis". The update requires limited partnerships and similar entities to be evaluated under the variable interest and voting interest models, eliminate the presumption that a general partner should consolidate a limited partnership, and simplify the identification of variable interests and related effect on the primary beneficiary criterion when fees are paid to a decision maker. The amendments have been applied using a full retrospective approach.

- ASU 2015-03, “Simplifying the Presentation of Debt Issuance Costs” and ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements". The updates require debt issuance costs to be presented on the balance sheet as a deduction from the carrying amount of the related liability. Previously, debt issuance costs were presented as a deferred charge within assets. The updates further clarify that regardless of whether there are outstanding borrowings, debt issuance costs arising from credit arrangements can be presented as an asset and subsequently amortized ratably over the term of the arrangement. These amendments have been applied retrospectively and resulted in a $30 million decrease in Other Assets, with a corresponding $30 million decrease in Long-Term Debt as at December 31, 2015.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. Recent Accounting Pronouncements (continued)

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, which replaces Topic 605, "Revenue Recognition", and other industry-specific guidance in the Accounting Standards Codification ("ASC"). 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, but permits early adoption using the original effective date of January 1, 2017. The standard can be applied using one of two retrospective application methods at the date of adoption. Encana is currently assessing the potential impact of the standard on the Company's Consolidated Financial Statements.

As of January 1, 2019, Encana will be required to adopt ASU 2016-02, “Leases” under Topic 842, which replaces 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 requiring leases recognized to be classified as either finance or operating leases was retained for the purpose of subsequent measurement and presentation 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 and provides for certain practical expedients. Encana is currently assessing the standard and expects the new standard will have a material impact on the Company's Consolidated Financial Statements.

3. Segmented Information

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

The interim Condensed Consolidated Statement of Earnings for the comparative period ended June 30, 2015 and the accompanying segmented information disclosed in this note have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these property taxes and other charges were presented in either transportation and processing expense or operating expense. Encana has updated its presentation to more accurately reflect these charges within the Condensed Consolidated Statement of Earnings based on the nature of the expense recognized and to more closely align with the Company's peers. As a result, for the three months ended June 30, 2015, the Canadian Operations reclassified $1 million from transportation and processing expense and $7 million from operating expense to production, mineral and other taxes. For the six months ended June 30, 2015, the Canadian Operations reclassified $3 million from transportation and processing expense and $13 million from operating expense to production, mineral and other taxes. In addition, for the three and six months ended June 30, 2015, the USA Operations reclassified $4 million and $14 million, respectively, from operating expense to production, mineral and other taxes.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the three months ended June 30)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2016	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties	**$ 252**	$ 387	**$ 460**	$ 629	**$ 92**	$ 88
Expenses						
Production, mineral and other taxes	**6**	8	**24**	30	**-**	-
Transportation and processing	**155**	170	**73**	144	**22**	-
Operating	**37**	38	**87**	147	**6**	8
Purchased product	**-**	-	**-**	-	**79**	79
	54	171	**276**	308	**(15)**	1
Depreciation, depletion and amortization	**67**	68	**143**	301	**-**	-
Impairments	**226**	-	**258**	2,081	**-**	-
	$ (239)	$ 103	**$ (125)**	$ (2,074)	**$ (15)**	$ 1

	Corporate & Other		Consolidated	
	2016	2015	**2016**	2015
Revenues, Net of Royalties	**$ (440)**	$ (274)	**$ 364**	$ 830
Expenses				
Production, mineral and other taxes	**-**	-	**30**	38
Transportation and processing	**(6)**	(15)	**244**	299
Operating	**5**	5	**135**	198
Purchased product	**-**	-	**79**	79
	(439)	(264)	**(124)**	216
Depreciation, depletion and amortization	**20**	25	**230**	394
Impairments	**-**	-	**484**	2,081
	$ (459)	$ (289)	**(838)**	(2,259)
Accretion of asset retirement obligation			**13**	11
Administrative			**61**	84
Interest			**107**	278
Foreign exchange (gain) loss, net			**23**	(86)
(Gain) loss on divestitures			**2**	(2)
Other			**24**	4
			230	289
Net Earnings (Loss) Before Income Tax			**(1,068)**	(2,548)
Income tax expense (recovery)			**(467)**	(938)
Net Earnings (Loss)			**$ (601)**	$ (1,610)

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2016	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties	**$ 713**	$ 1,117	**$ (621)**	$ (1,029)	**$ 92**	$ 88
Expenses						
Transportation and processing	**74**	89	**(52)**	(89)	**22**	-
Operating	**6**	8	**-**	-	**6**	8
Purchased product	**648**	1,019	**(569)**	(940)	**79**	79
Operating Cash Flow	**$ (15)**	$ 1	**$ -**	$ -	**$ (15)**	$ 1

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the six months ended June 30)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2016	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties	**$ 546**	$ 1,019	**$ 869**	$ 1,217	**$ 179**	$ 227
Expenses						
Production, mineral and other taxes	**12**	16	**41**	59	**-**	-
Transportation and processing	**304**	345	**171**	299	**43**	-
Operating	**77**	74	**200**	262	**14**	24
Purchased product	**-**	-	**-**	-	**152**	200
	153	584	**457**	597	**(30)**	3
Depreciation, depletion and amortization	**149**	173	**302**	637	**-**	-
Impairments	**493**	-	**903**	3,997	**-**	-
	$ (489)	$ 411	**$ (748)**	$ (4,037)	**$ (30)**	$ 3

	Corporate & Other		Consolidated	
	2016	2015	**2016**	2015
Revenues, Net of Royalties	**$ (477)**	$ (384)	**$ 1,117**	$ 2,079
Expenses				
Production, mineral and other taxes	**-**	-	**53**	75
Transportation and processing	**(5)**	(7)	**513**	637
Operating	**10**	11	**301**	371
Purchased product	**-**	-	**152**	200
	(482)	(388)	**98**	796
Depreciation, depletion and amortization	**40**	50	**491**	860
Impairments	**-**	-	**1,396**	3,997
	$ (522)	$ (438)	**(1,789)**	(4,061)
Accretion of asset retirement obligation			**26**	23
Administrative			**140**	156
Interest			**210**	403
Foreign exchange (gain) loss, net			**(356)**	570
(Gain) loss on divestitures			**2**	(16)
Other			**(63)**	5
			(41)	1,141
Net Earnings (Loss) Before Income Tax			**(1,748)**	(5,202)
Income tax expense (recovery)			**(768)**	(1,885)
Net Earnings (Loss)			**$ (980)**	$ (3,317)

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2016	2015	**2016**	2015	**2016**	2015
Revenues, Net of Royalties	**$ 1,402**	$ 2,282	**$ (1,223)**	$ (2,055)	**$ 179**	$ 227
Expenses						
Transportation and processing	**154**	184	**(111)**	(184)	**43**	-
Operating	**14**	24	**-**	-	**14**	24
Purchased product	**1,263**	2,071	**(1,111)**	(1,871)	**152**	200
Operating Cash Flow	**$ (29)**	$ 3	**$ (1)**	$ -	**$ (30)**	$ 3

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Capital Expenditures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Canadian Operations	**$ 54**	$ 114	**$ 117**	$ 265
USA Operations	**159**	628	**456**	1,211
Corporate & Other	**2**	1	**1**	3
	$ 215	$ 743	**$ 574**	$ 1,479

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

	Goodwill As at		Property, Plant and Equipment As at		Total Assets [(1)] As at	
	June 30, 2016	December 31, 2015	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Canadian Operations	**$ 703**	$ 661	**$ 640**	$ 1,100	**$ 1,582**	$ 2,036
USA Operations	**2,129**	2,129	**6,488**	7,249	**10,110**	10,405
Market Optimization	**-**	-	**2**	1	**57**	95
Corporate & Other	**-**	-	**1,562**	1,507	**3,177**	3,078
	$ 2,832	$ 2,790	**$ 8,692**	$ 9,857	**$ 14,926**	$ 15,614

(1) Total Assets for 2015 has been restated due to the adoption of ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs", as described in Note 2.

4. Acquisitions and Divestitures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Acquisitions				
Canadian Operations	**$ -**	$ 1	**$ -**	$ 1
USA Operations	**1**	2	**2**	3
Corporate & Other	**-**	-	**-**	34
Total Acquisitions	**1**	3	**2**	38
Divestitures				
Canadian Operations	**-**	(50)	**-**	(879)
USA Operations	**-**	(87)	**(6)**	(84)
Corporate & Other	**-**	(6)	**-**	(53)
Total Divestitures	**-**	(143)	**(6)**	(1,016)
Net Acquisitions & (Divestitures)	**$ 1**	$ (140)	**$ (4)**	$ (978)

Divestitures

For the six months ended June 30, 2016, divestitures in the USA Operations were $6 million. For the three and six months ended June 30, 2015, divestitures in the USA Operations were $87 million and $84 million, respectively. Divestitures primarily included the sale of certain properties that did not complement Encana's existing portfolio of assets.

For the three and six months ended June 30, 2015, divestitures in the Canadian Operations were $50 million and $879 million, respectively. Divestitures primarily included the sale of certain assets in Wheatland located in central and southern Alberta for proceeds of approximately C$558 million ($468 million), after closing adjustments, the sale of certain natural gas gathering and compression assets in Montney in northeastern British Columbia for proceeds of approximately C$454 million ($358 million), after closing adjustments and the sale of certain properties that did not complement Encana's existing portfolio of assets.

Amounts received from divestiture transactions were deducted from the respective Canadian and U.S. full cost pools.

For the six months ended June 30, 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Interest

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Interest Expense on:				
Debt	**$ 76**	$ 248	**$ 157**	$ 343
The Bow office building	**16**	18	**31**	34
Capital leases	**6**	6	**12**	15
Other	**9**	6	**10**	11
	$ 107	$ 278	**$ 210**	$ 403

Interest Expense on Debt for the three and six months ended June 30, 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.

6. Foreign Exchange (Gain) Loss, Net

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ 59**	$ (123)	**$ (277)**	$ 341
Translation of U.S. dollar risk management contracts issued from Canada	**-**	6	**6**	(29)
Translation of intercompany notes	**14**	(128)	**1**	2
	73	(245)	**(270)**	314
Foreign Exchange on Settlements	**(53)**	137	**(85)**	235
Other Monetary Revaluations	**3**	22	**(1)**	21
	$ 23	$ (86)	**$ (356)**	$ 570

7. Income Taxes

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Current Tax				
Canada	**$ (14)**	$ (38)	**$ (13)**	$ (25)
United States	**-**	2	**-**	3
Other countries	**2**	1	**4**	3
Total Current Tax Expense (Recovery)	**(12)**	(35)	**(9)**	(19)
Deferred Tax				
Canada	**(262)**	(155)	**(358)**	(478)
United States	**(252)**	(879)	**(608)**	(1,639)
Other countries	**59**	131	**207**	251
Total Deferred Tax Expense (Recovery)	**(455)**	(903)	**(759)**	(1,866)
Income Tax Expense (Recovery)	**$ (467)**	$ (938)	**$ (768)**	$ (1,885)

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 the 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

8. Property, Plant and Equipment, Net

	As at June 30, 2016			As at December 31, 2015		
	Cost	Accumulated DD&A [(1)]	Net	Cost	Accumulated DD&A [(1)]	Net
Canadian Operations						
Proved properties	$ 15,989	$ (15,728)	$ 261	$ 14,866	$ (14,170)	$ 696
Unproved properties	320	-	320	334	-	334
Other	59	-	59	70	-	70
	16,368	(15,728)	640	15,270	(14,170)	1,100
USA Operations						
Proved properties	26,344	(25,035)	1,309	25,723	(23,822)	1,901
Unproved properties	5,116	-	5,116	5,282	-	5,282
Other	63	-	63	66	-	66
	31,523	(25,035)	6,488	31,071	(23,822)	7,249
Market Optimization	6	(4)	2	5	(4)	1
Corporate & Other	2,216	(654)	1,562	2,098	(591)	1,507
	$ 50,113	$ (41,421)	$ 8,692	$ 48,444	$ (38,587)	$ 9,857

(1) Depreciation, depletion and amortization.

Canadian Operations and USA Operations property, plant and equipment include internal costs directly related to exploration, development and construction activities of $72 million, which have been capitalized during the six months ended June 30, 2016 (2015 - $128 million). Included in Corporate and Other are $59 million ($58 million as at December 31, 2015) of international property costs, which have been fully impaired.

For the three months ended June 30, 2016, the Company recognized before-tax ceiling test impairments of $226 million (2015 - nil) in the Canadian cost centre and $258 million (2015 - $2,081 million) in the U.S. cost centre. For the six months ended June 30, 2016, the Company recognized before-tax ceiling test impairments of $493 million (2015 - nil) in the Canadian cost centre and $903 million (2015 - $3,997 million) in the U.S. cost centre. The impairments are included within 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 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.

	Natural Gas		Oil & NGLs	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton Light Sweet (C$/bbl)
12-Month Average Trailing Reserves Pricing				
June 30, 2016	**2.24**	**2.14**	**43.12**	**52.46**
December 31, 2015	2.58	2.69	50.28	58.82
June 30, 2015	3.38	3.32	71.68	75.58

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 June 30, 2016, the total carrying value of assets under capital lease was $365 million ($376 million as at December 31, 2015), net of accumulated amortization of $348 million ($310 million as at December 31, 2015). Liabilities for the capital lease arrangements are included in other liabilities and provisions in the Condensed Consolidated Balance Sheet and are disclosed in Note 10.

Other Arrangement

As at June 30, 2016, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,243 million ($1,179 million as at December 31, 2015) 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 in 2037, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 10.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. Long-Term Debt

	As at June 30, 2016	As at December 31, 2015
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,493**	$ 650
U.S. Unsecured Notes		
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**	500
6.50% due February 1, 2038 (1)	**505**	800
5.15% due November 15, 2041 (1)	**244**	400
Total Principal	**5,704**	5,350
Increase in Value of Debt Acquired	**28**	27
Unamortized Debt Discounts and Issuance Costs (2)	**(42)**	(44)
Current Portion of Long-Term Debt	**-**	-
	$ 5,690	$ 5,333

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

(2) Long-Term Debt for 2015 has been restated due to the adoption of ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs", as described in Note 2.

As at June 30, 2016, total long-term debt had a carrying value of $5,690 million and a fair value of $5,740 million (as at December 31, 2015 - carrying value of $5,333 million and a fair value of $4,630 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, or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

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 announced 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 totals $89 million, which is included in other expenses in the Condensed Consolidated Statement of Earnings.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. Other Liabilities and Provisions

	As at June 30, 2016	As at December 31, 2015
The Bow Office Building (See Note 8)	**$ 1,312**	$ 1,238
Capital Lease Obligations (See Note 8)	**343**	353
Unrecognized Tax Benefits	**186**	189
Pensions and Other Post-Employment Benefits	**128**	115
Long-Term Incentives (See Note 16)	**43**	23
Other Derivative Contracts (See Notes 18, 19)	**20**	23
Other	**30**	34
	$ 2,062	$ 1,975

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 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has also subleased part of The Bow office space to a subsidiary of Cenovus Energy Inc. ("Cenovus"). The total undiscounted future payments related to the lease agreement and the total undiscounted future amounts expected to be recovered from the Cenovus sublease are outlined below.

(undiscounted)	2016	2017	2018	2019	2020	Thereafter	Total
Expected Future Lease Payments	$ 36	$ 73	$ 73	$ 74	$ 74	$ 1,400	**$ 1,730**
Sublease Recoveries	$ (18)	$ (36)	$ (36)	$ (36)	$ (37)	$ (687)	**$ (850)**

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 14.

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

	2016	2017	2018	2019	2020	Thereafter	Total
Expected Future Lease Payments	$ 50	$ 98	$ 99	$ 99	$ 99	$ 133	**$ 578**
Less Amounts Representing Interest	21	38	35	30	26	26	**176**
Present Value of Expected Future Lease Payments	$ 29	$ 60	$ 64	$ 69	$ 73	$ 107	**$ 402**

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. Asset Retirement Obligation

	As at June 30, 2016	As at December 31, 2015
Asset Retirement Obligation, Beginning of Year	**$ 814**	$ 913
Liabilities Incurred and Acquired	**4**	19
Liabilities Settled and Divested	**(13)**	(217)
Change in Estimated Future Cash Outflows	**-**	115
Accretion Expense	**26**	45
Foreign Currency Translation	**21**	(61)
Asset Retirement Obligation, End of Period	**$ 852**	$ 814
Current Portion	**$ 51**	$ 41
Long-Term Portion	**801**	773
	$ 852	$ 814

12. Share Capital

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.

Issued and Outstanding

	As at June 30, 2016		As at December 31, 2015	
	Number (millions)	**Amount**	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**849.8**	**$ 3,621**	741.2	$ 2,450
Common Shares Issued	**-**	**-**	98.4	1,098
Common Shares Issued Under Dividend Reinvestment Plan	**0.1**	**1**	10.2	73
Common Shares Outstanding, End of Period	**849.9**	**$ 3,622**	849.8	$ 3,621

During the six months ended June 30, 2016, Encana issued 86,848 common shares totaling $0.6 million under the Company's dividend reinvestment plan ("DRIP"). During the twelve months ended December 31, 2015, Encana issued 10,246,221 common shares totaling $73 million under the DRIP.

On March 5, 2015, Encana filed a prospectus supplement (the "Share Offering") to the Company's base 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 Share Offering were approximately C$1.44 billion ($1.13 billion). After deducting underwriter's fees and costs of the Share Offering, the net proceeds received were approximately C$1.39 billion ($1.09 billion).

Dividends

During the three months ended June 30, 2016, Encana paid dividends of $0.015 per common share totaling $12 million (2015 - $0.07 per common share totaling $55 million). During the six months ended June 30, 2016, Encana paid dividends of $0.03 per common share totaling $25 million (2015 - $0.14 per common share totaling $107 million). Common shares issued as part of the Share Offering as described above were not eligible to receive the dividend paid on March 31, 2015.

For the three and six months ended June 30, 2016, the dividends paid included $0.3 million and $0.6 million, respectively, in common shares issued in lieu of cash dividends under the DRIP (for the three and six months ended June 30, 2015 - $18 million and $32 million, respectively).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. Share Capital (continued)

Earnings Per Common Share

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

(millions, except per share amounts)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net Earnings (Loss)	**$ (601)**	$ (1,610)	**$ (980)**	$ (3,317)
Number of Common Shares:				
Weighted average common shares outstanding - Basic	**849.9**	841.2	**849.9**	799.5
Effect of dilutive securities	**-**	-	**-**	-
Weighted average common shares outstanding - Diluted	**849.9**	841.2	**849.9**	799.5
Net Earnings (Loss) per Common Share				
Basic	**$ (0.71)**	$ (1.91)	**$ (1.15)**	$ (4.15)
Diluted	**$ (0.71)**	$ (1.91)	**$ (1.15)**	$ (4.15)

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. All options outstanding as at June 30, 2016 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 whereby 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, Encana does not consider outstanding TSARs to be potentially dilutive securities.

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 an Encana common share, or the cash equivalent, as determined by Encana, upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. The Company intends to settle vested RSUs in cash on the vesting date. As a result, Encana does not consider RSUs to be potentially dilutive securities.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. Accumulated Other Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Foreign Currency Translation Adjustment				
Balance, Beginning of Period	**$ 1,113**	$ 1,193	**$ 1,383**	$ 715
Current Period Change in Foreign Currency Translation Adjustment	**14**	(53)	**(256)**	425
Balance, End of Period	**$ 1,127**	$ 1,140	**$ 1,127**	$ 1,140
Pension and Other Post-Employment Benefit Plans				
Balance, Beginning of Period	**$ 7**	$ (25)	**$ 7**	$ (26)
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 17)	**-**	-	**-**	1
Income Taxes	**-**	-	**-**	-
Balance, End of Period	**$ 7**	$ (25)	**$ 7**	$ (25)
Total Accumulated Other Comprehensive Income	**$ 1,134**	$ 1,115	**$ 1,134**	$ 1,115

14. Variable Interest Entities

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 June 30, 2016, Encana had a capital lease obligation of $336 million ($340 million as at December 31, 2015) related to the PFC.

Veresen Midstream Limited Partnership

On March 31, 2015, Encana, along with the Cutbank Ridge Partnership ("CRP"), entered into natural gas gathering and compression agreements with Veresen Midstream Limited Partnership (“VMLP”), under an initial term of 30 years with two potential five-year renewal terms. As part of the agreement, VMLP agreed to undertake future expansion of midstream services if required by Encana and the CRP in support of the anticipated future development of the Montney play. In addition, VMLP provides to Encana and the CRP natural gas gathering and processing under agreements that were contributed to VMLP by its partner Veresen Inc., and have remaining terms of 16 years and up to a potential maximum of 10 one-year renewal terms.

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 long-term service agreements which include: i) a take or pay for volumes committed to certain gathering and processing assets; ii) an operating fee of which a portion can be converted into a fixed fee once VMLP assumes operatorship of certain compression assets; and iii) a potential payout of minimum costs associated with certain gathering and compression assets. 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 service 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Variable Interest Entities (continued)

Veresen Midstream Limited Partnership (continued)

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 $1,414 million as at June 30, 2016. 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 20 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 June 30, 2016, accounts payable and accrued liabilities included $0.2 million related to the take or pay commitment.

15. Restructuring Charges

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 current low commodity price environment. Encana incurred total restructuring charges of $31 million, before tax, primarily related to severance costs, of which $6 million remains accrued as at June 30, 2016. The majority of the remaining amounts accrued are expected to be paid in 2017.

During the first quarter of 2015, Encana revised its plans to align the organizational structure in continued support of the Company's strategy that was announced in 2013. During the six months ended June 30, 2015, transition and severance costs of $31 million, before tax, were incurred.

Restructuring charges are included in administrative expense in the Condensed Consolidated Statement of Earnings.

16. Compensation Plans

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.

As at June 30, 2016, the following weighted average assumptions were used to determine the fair value of the share units held by employees:

	US$ Share Units	C$ Share Units
Risk Free Interest Rate	0.54%	0.54%
Dividend Yield	0.77%	0.79%
Expected Volatility Rate	53.96%	50.39%
Expected Term	1.7 yrs	2.0 yrs
Market Share Price	US$7.79	C$10.05

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. Compensation Plans (continued)

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

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Total Compensation Costs of Transactions Classified as Cash-Settled	**$ 38**	$ 13	**$ 46**	$ 7
Less: Total Share-Based Compensation Costs Capitalized	**(9)**	(5)	**(10)**	(2)
Total Share-Based Compensation Expense	**$ 29**	$ 8	**$ 36**	$ 5
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating expense	**$ 11**	$ 3	**$ 13**	$ 1
Administrative expense	**18**	5	**23**	4
	$ 29	$ 8	**$ 36**	$ 5

As at June 30, 2016, the liability for share-based payment transactions totaled $83 million ($51 million as at December 31, 2015), of which $40 million ($28 million as at December 31, 2015) is recognized in accounts payable and accrued liabilities and $43 million ($23 million as at December 31, 2015) is recognized in other liabilities and provisions in the Condensed Consolidated Balance Sheet.

	As at June 30, 2016	As at December 31, 2015
Liability for Cash-Settled Share-Based Payment Transactions:		
Unvested	**$ 67**	$ 47
Vested	**16**	4
	$ 83	$ 51

The following units were granted primarily in conjunction with the Company's March annual long-term incentive award. The TSARs and SARs were granted at the volume-weighted average trading price of Encana's common shares for the five days prior to the grant date.

Six Months Ended June 30, 2016 (thousands of units)	
TSARs	4,277
SARs	1,453
PSUs	5,841
DSUs	163
RSUs	15,092

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Pension and Other Post-Employment Benefits

The Company has recognized total benefit plans expense which includes pension benefits and other post-employment benefits ("OPEB") for the six months ended June 30 as follows:

	Pension Benefits		OPEB		Total	
	2016	2015	**2016**	2015	**2016**	2015
Defined Benefit Plan Expense	**$ (1)**	$ 1	**$ 7**	$ 7	**$ 6**	$ 8
Defined Contribution Plan Expense	**14**	15	**-**	-	**14**	15
Total Benefit Plans Expense	**$ 13**	$ 16	**$ 7**	$ 7	**$ 20**	$ 23

Of the total benefit plans expense, $16 million (2015 - $18 million) was included in operating expense and $4 million (2015 - $5 million) was included in administrative expense.

The defined periodic pension and OPEB expense for the six months ended June 30 are as follows:

	Pension Benefits		OPEB		Total	
	2016	2015	**2016**	2015	**2016**	2015
Current Service Costs	**$ 1**	$ 2	**$ 5**	$ 5	**$ 6**	$ 7
Interest Cost	**4**	5	**2**	2	**6**	7
Expected Return On Plan Assets	**(6)**	(7)	**-**	-	**(6)**	(7)
Amounts Reclassified From Accumulated Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses	**-**	1	**-**	-	**-**	1
Total Defined Benefit Plan Expense	**$ (1)**	$ 1	**$ 7**	$ 7	**$ 6**	$ 8

The amounts recognized in other comprehensive income for the six months ended June 30 are as follows:

	Pension Benefits		OPEB		Total	
	2016	2015	**2016**	2015	**2016**	2015
Total Amounts Recognized in Other Comprehensive (Income) Loss, Before Tax	**$ -**	$ (1)	**$ -**	$ -	**$ -**	$ (1)
Total Amounts Recognized in Other Comprehensive (Income) Loss, After Tax	**$ -**	$ (1)	**$ -**	$ -	**$ -**	$ (1)

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Fair Value Measurements

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. The fair value of cash in reserve approximates its carrying amount due to the nature of the instrument held.

Recurring fair value measurements are performed for risk management assets and liabilities and other derivative liabilities, as discussed further in Note 19. These items are carried at fair value in the Condensed Consolidated Balance Sheet and are classified within the three levels of the fair value hierarchy in the tables below. There have been no significant transfers between the hierarchy levels during the period.

As at June 30, 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						
Risk Management Assets						
Current	**$ -**	**$ 82**	**$ 16**	**$ 98**	**$ (65)**	**$ 33**
Long-term	**-**	**1**	**-**	**1**	**(1)**	**-**
Risk Management Liabilities						
Current	**-**	**185**	**12**	**197**	**(65)**	**132**
Long-term	**-**	**57**	**5**	**62**	**(1)**	**61**
Other Derivative Liabilities						
Current in accounts payable and accrued liabilities	**$ -**	**$ 6**	**$ -**	**$ 6**	**$ -**	**$ 6**
Long-term in other liabilities and provisions	**-**	**20**	**-**	**20**	**-**	**20**

As at December 31, 2015	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						
Risk Management Assets						
Current	$ 1	$ 356	$ 37	$ 394	$ (27)	$ 367
Long-term	-	11	-	11	-	11
Risk Management Liabilities						
Current	-	31	12	43	(27)	16
Long-term	-	-	9	9	-	9
Other Derivative Liabilities						
Current in accounts payable and accrued liabilities	$ -	$ 6	$ -	$ 6	$ -	$ 6
Long-term in other liabilities and provisions	-	23	-	23	-	23

[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 fixed price swaptions, NYMEX three-way options, NYMEX costless collars, WTI-based fixed price swaptions and basis swaps with terms to 2018. Level 2 also includes other derivative liabilities as discussed in Note 19. 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Fair Value Measurements (continued)

Level 3 Fair Value Measurements

As at June 30, 2016, the Company's Level 3 risk management assets and liabilities consist of power purchase contracts and WTI three-way options with terms to 2017. The fair values of the power purchase contracts are based on the income approach and are modelled internally using observable and unobservable inputs such as forward power prices in less active markets. The WTI three-way options are a combination of a sold call, bought put and a sold 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 partial downside price protection through the combination of the put options. The fair values of the WTI three-way options 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.

Changes in amounts related to risk management assets and liabilities are recognized in revenues and transportation and processing expense according to their purpose.

A summary of changes in Level 3 fair value measurements for the six months ended June 30 is presented below:

	Risk Management	
	2016	2015
Balance, Beginning of Year	**$ 16**	$ (18)
Total Gains (Losses)	**(4)**	-
Purchases and Settlements:		
Purchases	**-**	-
Settlements	**(3)**	8
Transfers in and out of Level 3 (1)	**(10)**	-
Balance, End of Period	**$ (1)**	$ (10)
Change in unrealized gains (losses) related to assets and liabilities held at end of period	**$ (7)**	$ 3

(1) The Company's policy is to recognize transfers in and out of Level 3 on the date of the event of change in circumstances that caused the transfer.

Quantitative information about unobservable inputs used in Level 3 fair value measurements is presented below:

	Valuation Technique	Unobservable Input	**As at June 30, 2016**	As at December 31, 2015
Risk Management - Power	Discounted Cash Flow	Forward prices ($/Megawatt Hour)	**$33.71 - $37.50**	$34.50 - $40.25
Risk Management - WTI Three-Way Options	Option Model	Implied Volatility	**22% - 49%**	33% - 64%

A 10 percent increase or decrease in estimated forward power prices would cause a corresponding $3 million ($4 million as at December 31, 2015) increase or decrease to net risk management assets and liabilities. A 10 percent increase or decrease in implied volatility for the WTI three-way options would cause a corresponding $2 million ($2 million as at December 31, 2015) increase or decrease to net risk management assets and liabilities.

19. Financial Instruments and Risk Management

A) Financial Instruments

Encana's financial assets and liabilities are recognized in cash and cash equivalents, accounts receivable and accrued revenues, cash in reserve, accounts payable and accrued liabilities, risk management assets and liabilities, other liabilities and provisions and long-term debt.

B) Risk Management Assets and Liabilities

Risk management assets and liabilities arise from the use of derivative financial instruments and are measured at fair value. See Note 18 for a discussion of fair value measurements.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

Unrealized Risk Management Position		**As at June 30, 2016**		As at December 31, 2015
Risk Management Assets				
Current	**$**	**33**	$	367
Long-term		**-**		11
		33		378
Risk Management Liabilities				
Current		**132**		16
Long-term		**61**		9
		193		25
Other Derivative Liabilities				
Current in accounts payable and accrued liabilities		**6**		6
Long-term in other liabilities and provisions		**20**		23
Net Risk Management Assets (Liabilities) and Other Derivative Liabilities	**$**	**(186)**	$	324

Commodity Price Positions as at June 30, 2016

	Notional Volumes		Term	Average Price			Fair Value
Natural Gas Contracts							
Fixed Price Contracts							
NYMEX Fixed Price	859	MMcf/d	Q3-Q4 2016	2.68	US$/Mcf	**$**	**(50)**
	350	MMcf/d	Q1 2017	3.07	US$/Mcf		**(10)**
NYMEX Fixed Price Swaptions [(1)]	345	MMcf/d	2017	2.70	US$/Mcf		**(68)**
NYMEX Three-Way Options	300	MMcf/d	2017				**(32)**
Sold call price				3.07	US$/Mcf		
Bought put price				2.75	US$/Mcf		
Sold put price				2.27	US$/Mcf		
NYMEX Costless Collars	335	MMcf/d	Q3-Q4 2016				**(35)**
Sold call price				2.46	US$/Mcf		
Bought put price				2.22	US$/Mcf		
Basis Contracts [(2)]			2016				**9**
Other Financial Positions							**(2)**
Natural Gas Fair Value Position							**(188)**
Crude Oil and NGLs Contracts							
Fixed Price Contracts							
WTI Fixed Price	46.5	Mbbls/d	Q3-Q4 2016	56.35	US$/bbl		**55**
	15.5	Mbbls/d	2017	49.49	US$/bbl		**(15)**
WTI Fixed Price Swaptions [(3)]	10.0	Mbbls/d	Q2 2017	50.86	US$/bbl		**(6)**
WTI Three-Way Options	22.4	Mbbls/d	Q3-Q4 2016				**15**
Sold call price				62.99	US$/bbl		
Bought put price				55.00	US$/bbl		
Sold put price				47.11	US$/bbl		
WTI Three-Way Options	10.0	Mbbls/d	Q3-Q4 2017				**1**
Sold call price				65.00	US$/bbl		
Bought put price				50.25	US$/bbl		
Sold put price				40.00	US$/bbl		
Basis Contracts [(4)]			2016-2018				**(5)**
Crude Oil and NGLs Fair Value Position							**45**
Power Purchase Contracts and Other Derivative Contracts							
Fair Value Position							**(43)**
Total Fair Value Position						**$**	**(186)**

(1) NYMEX Fixed Price Swaptions give the counterparty the option to extend 2016 fixed price swaps to December 31, 2017 at the strike price.

(2) Encana has entered into swaps to protect against widening natural gas price differentials between benchmark and regional sales prices.

(3) WTI Fixed Price Swaptions give the counterparty the option to extend Q1 2017 fixed price swaps to June 30, 2017 at the strike price.

(4) Encana has entered into swaps to protect against widening Midland and NGL differentials to WTI.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Revenues, Net of Royalties	**$ 127**	$ 164	**$ 304**	$ 409
Transportation and Processing	**2**	(3)	**(4)**	(8)
Gain (Loss) on Risk Management	**$ 129**	$ 161	**$ 300**	$ 401

	Unrealized Gain (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Revenues, Net of Royalties	**$ (457)**	$ (293)	**$ (511)**	$ (421)
Transportation and Processing	**6**	15	**5**	7
Gain (Loss) on Risk Management	**$ (451)**	$ (278)	**$ (506)**	$ (414)

Reconciliation of Unrealized Risk Management Positions from January 1 to June 30

	2016		2015
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 324**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**(206)**	**$ (206)**	$ (13)
Foreign Exchange Translation Adjustment on Canadian Dollar Contracts	**(1)**		
Settlement of Acquired Crude Oil Contracts	**(6)**		
Settlement of Other Derivative Contracts	**3**		
Fair Value of Contracts Realized During the Period	**(300)**	**(300)**	(401)
Fair Value of Contracts, End of Period	**$ (186)**	**$ (506)**	$ (414)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks including market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. Future cash flows may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

Commodity Price Risk

Commodity price risk arises from the effect 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.

Natural Gas - To partially mitigate natural gas commodity price risk, the Company uses NYMEX-based contracts such as fixed price contracts, fixed price swaptions, options and costless collars. Encana also enters into basis swaps to manage against widening price differentials between various production areas and various sales points.

Crude Oil and NGLs - To partially mitigate crude oil and NGLs commodity price risk, the Company uses WTI-based contracts such as fixed price contracts, fixed price swaptions and options. Encana also enters into basis swaps to manage against widening price differentials between various production areas and various sales points.

Power - The Company has entered into Canadian dollar denominated derivative contracts to manage its electricity consumption costs.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities (continued)

Commodity Price Risk (continued)

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 for the six months ended June 30 as follows:

	2016		2015	
	10% Price Increase	**10% Price Decrease**	10% Price Increase	10% Price Decrease
Natural Gas Price	**$ (138)**	**$ 130**	$ (39)	$ 39
Crude Oil Price	**(92)**	**87**	(150)	150
Power Price	**3**	**(3)**	6	(6)

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. This credit risk exposure is mitigated through the use of Board-approved credit policies 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 at June 30, 2016, the Company had no significant credit derivatives in place and held no collateral balances.

As at June 30, 2016, 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 in Canada and the U.S. or with counterparties having 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 June 30, 2016, approximately 87 percent (95 percent as at December 31, 2015) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at June 30, 2016, Encana had four 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 June 30, 2016, these counterparties accounted for 30 percent, 22 percent, 16 percent and 15 percent of the fair value of the outstanding in-the-money net risk management contracts. As at December 31, 2015, Encana had two counterparties whose net settlement position accounted for 13 percent and 11 percent of the fair value of the outstanding in-the-money net risk management contracts.

During 2015, 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 purchaser. The circumstances that would require Encana to perform under the agreement includes events where the purchaser fails to make payment to the guaranteed party and/or the purchaser is subject to an insolvency event. The agreements have remaining terms from five to eight years with a fair value of $26 million ($29 million as at December 31, 2015). The maximum potential amount of undiscounted future payments is $420 million as at June 30, 2016, and is considered unlikely.

Liquidity Risk

Liquidity risk arises from the potential that the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages liquidity risk using cash and debt management programs.

The Company has access to cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities and debt and equity capital markets. As at June 30, 2016, the Company had committed revolving 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 latter of which remained unused. Of the $3.0 billion revolving bank credit facility, $1,493 million of LIBOR loans were drawn and $1,507 million remained unused. The facilities remain committed through July 2020.

Encana also has accessible capacity under a shelf prospectus for up to $4.9 billion, or the equivalent in foreign currencies, the availability of which is dependent on certain eligibility requirements and market conditions, to issue debt and/or equity securities in Canada and/or the U.S. The shelf prospectus expires in July 2016.

The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities (continued)

Liquidity Risk (continued)

The Company minimizes its liquidity risk by managing its capital structure. The Company's capital structure consists of 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 to finance internally generated growth as well as potential acquisitions. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt.

The timing of expected cash outflows relating to financial liabilities is outlined in the table below:

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	6 - 9 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 1,239	$ -	$ -	$ -	$ -	**$ 1,239**
Risk Management Liabilities	132	61	-	-	-	**193**
Long-Term Debt [1]	303	1,105	1,980	1,457	5,128	**9,973**
Other Liabilities and Provisions	-	15	1	4	-	**20**

(1) Principal and interest.

Included in Encana's long-term debt obligations of $9,973 million at June 30, 2016 are $1,493 million in principal obligations related to LIBOR loans. These amounts are fully supported and Management expects they will continue to be supported by credit facilities which are fully revolving for up to five years. Based on the July 2020 maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 Years. Further information on Long-Term Debt is contained in Note 9.

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 primarily in North America, fluctuations in the exchange rate between the U.S. and Canadian dollars can have a significant effect on the Company's reported results. Encana's financial results are consolidated in Canadian dollars; however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations is not separately identifiable.

As at June 30, 2016, Encana had $5.7 billion in U.S. dollar debt issued from Canada that was subject to foreign exchange exposure ($5.4 billion as at December 31, 2015). To mitigate the exposure to the fluctuating U.S./Canadian dollar exchange rate, Encana may enter into foreign exchange derivatives. There were no foreign exchange derivatives outstanding as at June 30, 2016.

Encana's foreign exchange (gain) loss primarily includes foreign exchange gains and losses on the translation and settlement of U.S. dollar denominated debt issued from Canada, unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated risk management assets and liabilities held in Canada, foreign exchange gains and losses on the translation and settlement of foreign denominated intercompany balances and foreign exchange gains and losses on U.S. dollar denominated cash and short-term investments held in Canada. A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $43 million change in foreign exchange (gain) loss as at June 30, 2016 (2015 - $50 million).

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 partially mitigates 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. There were no interest rate derivatives outstanding as at June 30, 2016.

As at June 30, 2016, the Company had floating rate debt of $1,493 million (2015 - $1,397 million). Accordingly, the sensitivity in net earnings for each one percent change in interest rates on floating rate debt was $11 million (2015 - $10 million).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

20. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at June 30, 2016:

	Expected Future Payments						
(undiscounted)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation and Processing	$ 257	$ 569	$ 580	$ 652	$ 626	$ 3,136	**$ 5,820**
Drilling and Field Services	74	115	67	30	15	4	**305**
Operating Leases	14	25	24	11	3	19	**96**
Total	$ 345	$ 709	$ 671	$ 693	$ 644	$ 3,159	**$ 6,221**

Included within transportation and processing in the table above are certain commitments associated with midstream service agreements with VMLP as described in Note 14. Divestiture transactions can reduce certain commitments disclosed above.

Contingencies

Encana is involved in various legal claims and actions arising in the 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 adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Encana Corporation

Interim Supplemental Information
(unaudited)

For the period ended June 30, 2016

U.S. Dollars / U.S. Protocol

Supplemental Financial Information *(unaudited)*

Financial Results

	2016			2015					
($ millions, except per share amounts)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Cash Flow [1]	**284**	**182**	102	1,430	383	371	676	181	495
Per share - Diluted [4]	**0.33**	**0.21**	0.12	1.74	0.45	0.44	0.85	0.22	0.65
Operating Earnings (Loss) [2,3]	**(41)**	**89**	(130)	(61)	111	(24)	(148)	(167)	19
Per share - Diluted [4]	**(0.05)**	**0.10**	(0.15)	(0.07)	0.13	(0.03)	(0.19)	(0.20)	0.03
Net Earnings (Loss)	**(980)**	**(601)**	(379)	(5,165)	(612)	(1,236)	(3,317)	(1,610)	(1,707)
Per share - Diluted [4]	**(1.15)**	**(0.71)**	(0.45)	(6.28)	(0.72)	(1.47)	(4.15)	(1.91)	(2.25)
Effective Tax Rate using Canadian Statutory Rate	**27.0%**			26.4%					
Foreign Exchange Rates (US$ per C$1)									
Average	**0.752**	**0.776**	0.728	0.782	0.749	0.764	0.810	0.813	0.806
Period end	**0.769**	**0.769**	0.771	0.723	0.723	0.747	0.802	0.802	0.789
Cash Flow Summary									
Cash From (Used in) Operating Activities	**240**	**83**	157	1,681	448	453	780	298	482
Deduct (Add back):									
Net change in other assets and liabilities	**(9)**	**(5)**	(4)	(11)	7	(18)	-	7	(7)
Net change in non-cash working capital	**(35)**	**(94)**	59	262	58	100	104	110	(6)
Cash tax on sale of assets	**-**	**-**	-	-	-	-	-	-	-
Cash Flow [1]	**284**	**182**	102	1,430	383	371	676	181	495
Operating Earnings Summary									
Net Earnings (Loss)	**(980)**	**(601)**	(379)	(5,165)	(612)	(1,236)	(3,317)	(1,610)	(1,707)
After-tax (addition) deduction:									
Unrealized hedging gain (loss)	**(345)**	**(310)**	(35)	(244)	(66)	107	(285)	(187)	(98)
Impairments	**(938)**	**(331)**	(607)	(4,130)	(514)	(1,066)	(2,550)	(1,328)	(1,222)
Restructuring charges [3]	**(22)**	**-**	(22)	(45)	(5)	(20)	(20)	(10)	(10)
Non-operating foreign exchange gain (loss)	**247**	**(48)**	295	(702)	(96)	(212)	(394)	114	(508)
Gain (loss) on divestitures	**(1)**	**(1)**	-	9	-	(2)	11	1	10
Gain on debt retirement	**65**	**-**	65	-	-	-	-	-	-
Income tax adjustments	**55**	**-**	55	8	(42)	(19)	69	(33)	102
Operating Earnings (Loss) [2,3]	**(41)**	**89**	(130)	(61)	111	(24)	(148)	(167)	19

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

(2) Operating Earnings (Loss) is a non-GAAP measure defined as net earnings (loss) excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures, gains on debt retirement, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

(3) In Q2 2015, organizational structure changes were formalized which resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.

(4) Net earnings (loss), operating earnings (loss) and cash flow per common share are calculated using the weighted average number of Encana common shares outstanding as follows:

	2016			2015					
(millions)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Weighted Average Common Shares Outstanding									
Basic	**849.9**	**849.9**	849.9	822.1	846.5	843.1	799.5	841.2	757.8
Diluted	**849.9**	**849.9**	849.9	822.1	846.5	843.1	799.5	841.2	757.8

Supplemental Financial & Operating Information *(unaudited)*

Financial Metrics

	2016 Year-to-date	2015 Year
Debt to Debt Adjusted Cash Flow	**4.2x**	2.8x
Debt to Adjusted Capitalization	**31%**	28%

The financial metrics disclosed above are non-GAAP measures monitored by Management as indicators of the Company's overall financial strength. These non-GAAP measures are defined and calculated in the Non-GAAP Measures section of Encana's Management's Discussion and Analysis.

Net Capital Investment

	2016			2015					
($ millions)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Capital Investment									
Canadian Operations	**117**	**54**	63	380	39	76	265	114	151
USA Operations	**456**	**159**	297	1,847	242	394	1,211	628	583
Market Optimization	**-**	**-**	-	1	-	1	-	-	-
Corporate & Other	**1**	**2**	(1)	4	(1)	2	3	1	2
Capital Investment	**574**	**215**	359	2,232	280	473	1,479	743	736
Net Acquisitions & (Divestitures)	**(4)**	**1**	(5)	(1,838)	(761)	(99)	(978)	(140)	(838)
Net Capital Investment	**570**	**216**	354	394	(481)	374	501	603	(102)

Core Four Capital Investment

	2016			2015					
($ millions)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Capital Investment									
Montney	**63**	**27**	36	159	15	17	127	48	79
Duvernay	**54**	**27**	27	205	20	58	127	57	70
Eagle Ford	**114**	**38**	76	570	56	142	372	175	197
Permian	**316**	**112**	204	916	155	219	542	325	217
Total Core Four	**547**	**204**	343	1,850	246	436	1,168	605	563
% of Total Encana	**95%**	**95%**	96%	83%	88%	92%	79%	81%	76%

Supplemental Operating Information *(unaudited)*

Production Volumes - After Royalties

	2016			2015					
(average)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas (MMcf/d)	**1,466**	**1,418**	1,516	1,635	1,571	1,547	1,712	1,568	1,857
Oil (Mbbls/d)	**79.7**	**78.9**	80.5	87.0	90.6	91.9	82.7	86.2	79.2
NGLs (Mbbls/d)	**51.7**	**53.1**	50.3	46.4	54.4	48.5	41.3	41.1	41.5
Oil & NGLs (Mbbls/d)	**131.4**	**132.0**	130.8	133.4	145.0	140.4	124.0	127.3	120.7
Total (MBOE/d)	**375.8**	**368.3**	383.4	405.9	406.8	398.3	409.3	388.7	430.1

Production Volumes - After Royalties

	2016			2015					
(average)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas (MMcf/d)									
Canadian Operations	**1,018**	**971**	1,066	971	1,001	876	1,004	881	1,128
USA Operations	**448**	**447**	450	664	570	671	708	687	729
	1,466	**1,418**	1,516	1,635	1,571	1,547	1,712	1,568	1,857
Oil (Mbbls/d)									
Canadian Operations	**3.3**	**3.3**	3.2	5.6	4.0	5.3	6.5	6.5	6.6
USA Operations	**76.4**	**75.6**	77.3	81.4	86.6	86.6	76.2	79.7	72.6
	79.7	**78.9**	80.5	87.0	90.6	91.9	82.7	86.2	79.2
NGLs (Mbbls/d)									
Canadian Operations	**27.0**	**27.1**	27.0	22.8	28.2	21.9	20.5	19.8	21.2
USA Operations	**24.7**	**26.0**	23.3	23.6	26.2	26.6	20.8	21.3	20.3
	51.7	**53.1**	50.3	46.4	54.4	48.5	41.3	41.1	41.5
Oil & NGLs (Mbbls/d)									
Canadian Operations	**30.3**	**30.4**	30.2	28.4	32.2	27.2	27.0	26.3	27.8
USA Operations	**101.1**	**101.6**	100.6	105.0	112.8	113.2	97.0	101.0	92.9
	131.4	**132.0**	130.8	133.4	145.0	140.4	124.0	127.3	120.7
Total (MBOE/d)									
Canadian Operations	**200.0**	**192.2**	207.9	190.2	199.1	173.2	194.4	173.2	215.8
USA Operations	**175.8**	**176.1**	175.5	215.7	207.7	225.1	214.9	215.5	214.3
	375.8	**368.3**	383.4	405.9	406.8	398.3	409.3	388.7	430.1

Oil & NGLs Production Volumes - After Royalties

	2016				2015						
(average Mbbls/d)	**% of Total**	**Year-to-date**	**Q2**	Q1	% of Total	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil	**61**	**79.7**	**78.9**	80.5	65	87.0	90.6	91.9	82.7	86.2	79.2
Plant Condensate	**15**	**19.9**	**20.7**	19.1	13	16.8	22.4	16.8	14.0	13.9	14.0
Butane	**6**	**8.6**	**8.9**	8.3	6	7.5	8.5	8.0	6.7	6.3	7.2
Propane	**10**	**13.0**	**13.0**	13.1	9	12.2	13.3	13.5	11.1	12.4	9.7
Ethane	**8**	**10.2**	**10.5**	9.8	7	9.9	10.2	10.2	9.5	8.5	10.6
	100	**131.4**	**132.0**	130.8	100	133.4	145.0	140.4	124.0	127.3	120.7

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

Revenues, Net of Royalties, and Realized Financial Hedging

	2016			2015					
($ millions)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Canadian Operations									
Revenues, Net of Royalties, excluding Hedging (1)									
Natural Gas	**265**	**103**	162	976	188	199	589	193	396
Oil & NGLs	**155**	**93**	62	333	90	75	168	91	77
	420	**196**	224	1,309	278	274	757	284	473
Realized Financial Hedging Gain (Loss)									
Natural Gas	**93**	**47**	46	479	115	104	260	106	154
Oil & NGLs	**29**	**8**	21	16	14	5	(3)	(5)	2
	122	**55**	67	495	129	109	257	101	156
USA Operations									
Revenues, Net of Royalties, excluding Hedging (1)									
Natural Gas	**148**	**70**	78	629	118	170	341	146	195
Oil & NGLs	**529**	**312**	217	1,412	332	371	709	414	295
	677	**382**	295	2,041	450	541	1,050	560	490
Realized Financial Hedging Gain (Loss)									
Natural Gas	**35**	**19**	16	239	73	54	112	58	54
Oil & NGLs	**143**	**50**	93	185	88	54	43	5	38
	178	**69**	109	424	161	108	155	63	92

(1) Excludes other revenues with no associated volumes.

Per-unit Results, Excluding the Impact of Realized Financial Hedging

	2016			2015 (1)					
($/BOE)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Total - Canadian Operations									
Price	**11.55**	**11.23**	11.84	18.84	15.14	17.22	21.50	18.05	24.30
Production, mineral and other taxes	**0.33**	**0.36**	0.29	0.41	0.31	0.42	0.46	0.45	0.46
Transportation and processing	**8.34**	**8.85**	7.87	9.42	8.64	9.47	9.80	10.77	9.00
Operating	**2.06**	**2.08**	2.06	2.17	2.38	2.09	2.09	2.43	1.82
Netback	**0.82**	**(0.06)**	1.62	6.84	3.81	5.24	9.15	4.40	13.02
Total - USA Operations									
Price	**21.16**	**23.89**	18.42	25.93	23.55	26.13	26.99	28.61	25.34
Production, mineral and other taxes	**1.27**	**1.48**	1.07	1.47	1.31	1.52	1.51	1.53	1.50
Transportation and processing	**5.34**	**4.56**	6.12	7.37	6.57	7.52	7.68	7.34	8.02
Operating	**6.20**	**5.34**	7.06	6.55	6.18	6.63	6.69	7.46	5.91
Netback	**8.35**	**12.51**	4.17	10.54	9.49	10.46	11.11	12.28	9.91
Total Operations Netback									
Price	**16.05**	**17.29**	14.85	22.61	19.44	22.26	24.38	23.90	24.82
Production, mineral and other taxes	**0.77**	**0.89**	0.65	0.97	0.82	1.04	1.01	1.05	0.98
Transportation and processing	**6.94**	**6.80**	7.07	8.33	7.58	8.38	8.69	8.87	8.50
Operating (2)	**4.00**	**3.63**	4.35	4.50	4.32	4.66	4.50	5.22	3.85
Netback	**4.34**	**5.97**	2.78	8.81	6.72	8.18	10.18	8.76	11.49

(1) Updated to reflect the reclassification of property taxes and certain other levied charges from transportation and processing expense and/or operating expense to production, mineral and other taxes. There were no changes to the reported totals for Netbacks.

(2) 2016 year-to-date operating expense includes costs related to long-term incentives of $0.15/BOE (2015 year-to-date - costs of $0.01/BOE).

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties

Per-unit Prices, Excluding the Impact of Realized Financial Hedging

	2016			2015					
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas Price ($/Mcf)									
Canadian Operations	**1.43**	**1.18**	1.66	2.75	2.04	2.48	3.23	2.39	3.89
USA Operations	**1.81**	**1.74**	1.88	2.60	2.29	2.75	2.66	2.33	2.97
Total Operations	**1.55**	**1.35**	1.73	2.69	2.13	2.60	3.00	2.37	3.53
Oil & NGLs Price ($/bbl)									
Canadian Operations	**28.13**	**33.40**	22.82	32.10	30.08	29.75	34.53	38.57	30.65
USA Operations	**28.77**	**33.76**	23.74	36.80	31.81	35.66	40.43	45.21	35.18
Total Operations	**28.63**	**33.67**	23.53	35.80	31.43	34.52	39.14	43.83	34.13
Total Price ($/BOE)									
Canadian Operations	**11.55**	**11.23**	11.84	18.84	15.14	17.22	21.50	18.05	24.30
USA Operations	**21.16**	**23.89**	18.42	25.93	23.55	26.13	26.99	28.61	25.34
Total Operations	**16.05**	**17.29**	14.85	22.61	19.44	22.26	24.38	23.90	24.82

Impact of Realized Financial Hedging

	2016			2015					
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas ($/Mcf)									
Canadian Operations	**0.50**	**0.53**	0.48	1.35	1.25	1.28	1.43	1.32	1.52
USA Operations	**0.43**	**0.47**	0.39	0.99	1.39	0.88	0.88	0.93	0.82
Total Operations	**0.48**	**0.51**	0.45	1.20	1.30	1.11	1.20	1.15	1.25
Oil & NGLs ($/bbl)									
Canadian Operations	**5.21**	**2.72**	7.70	1.56	4.80	2.09	(0.68)	(2.21)	0.78
USA Operations	**7.76**	**5.43**	10.11	4.83	8.50	5.17	2.45	0.52	4.58
Total Operations	**7.17**	**4.80**	9.56	4.13	7.68	4.57	1.77	(0.05)	3.70
Total ($/BOE)									
Canadian Operations	**3.35**	**3.12**	3.56	7.13	7.05	6.82	7.30	6.39	8.04
USA Operations	**5.56**	**4.32**	6.79	5.39	8.43	5.21	3.99	3.22	4.78
Total Operations	**4.38**	**3.69**	5.04	6.20	7.75	5.91	5.56	4.63	6.42

Per-unit Results, Including the Impact of Realized Financial Hedging

	2016			2015					
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas Price ($/Mcf)									
Canadian Operations	**1.93**	**1.71**	2.14	4.10	3.29	3.76	4.66	3.71	5.41
USA Operations	**2.24**	**2.21**	2.27	3.59	3.68	3.63	3.54	3.26	3.79
Total Operations	**2.03**	**1.86**	2.18	3.89	3.43	3.71	4.20	3.52	4.78
Oil & NGLs Price ($/bbl)									
Canadian Operations	**33.34**	**36.12**	30.52	33.66	34.88	31.84	33.85	36.36	31.43
USA Operations	**36.53**	**39.19**	33.85	41.63	40.31	40.83	42.88	45.73	39.76
Total Operations	**35.80**	**38.47**	33.09	39.93	39.11	39.09	40.91	43.78	37.83
Total Price ($/BOE)									
Canadian Operations	**14.90**	**14.35**	15.40	25.97	22.19	24.04	28.80	24.44	32.34
USA Operations	**26.72**	**28.21**	25.21	31.32	31.98	31.34	30.98	31.83	30.12
Total Operations	**20.43**	**20.98**	19.89	28.81	27.19	28.17	29.94	28.53	31.24
Total Netback ($/BOE)									
Canadian Operations	**4.17**	**3.06**	5.18	13.97	10.86	12.06	16.45	10.79	21.06
USA Operations	**13.91**	**16.83**	10.96	15.93	17.92	15.67	15.10	15.50	14.69
Total Operations	**8.72**	**9.66**	7.82	15.01	14.47	14.09	15.74	13.39	17.91

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play

	2016			2015					
(after royalties)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Natural Gas Production (MMcf/d)									
Canadian Operations									
Montney	**803**	**781**	826	723	778	711	701	685	717
Duvernay	**52**	**57**	48	27	48	26	17	17	16
Other Upstream Operations (1)									
Wheatland	**78**	**83**	76	86	78	80	94	76	111
Deep Panuke	**39**	**12**	67	63	40	-	107	32	182
Other and emerging (2)	**46**	**38**	49	72	57	59	85	71	102
Total Canadian Operations	**1,018**	**971**	1,066	971	1,001	876	1,004	881	1,128
USA Operations									
Eagle Ford	**48**	**50**	46	44	57	48	36	36	36
Permian	**49**	**52**	46	44	49	54	36	38	34
Other Upstream Operations (1)									
DJ Basin	**55**	**55**	56	55	59	55	52	55	49
San Juan	**10**	**9**	11	13	11	15	14	15	13
Piceance	**280**	**275**	286	320	301	311	333	324	343
Haynesville	**-**	**-**	-	173	84	177	217	204	230
Other and emerging	**6**	**6**	5	15	9	11	20	15	24
Total USA Operations	**448**	**447**	450	664	570	671	708	687	729
Natural Gas Production (MMcf/d)									
Total Core Four	**952**	**940**	966	838	932	839	790	776	803
% of Total Encana	**65%**	**66%**	64%	51%	59%	54%	46%	49%	43%
Oil & NGLs Production (Mbbls/d)									
Canadian Operations									
Montney	**21.7**	**21.1**	22.3	22.5	23.2	21.8	22.5	21.6	23.3
Duvernay	**8.2**	**8.8**	7.6	4.8	8.5	4.9	2.9	3.0	2.8
Other Upstream Operations (1)									
Wheatland	**0.4**	**0.4**	0.3	0.9	0.5	0.4	1.5	1.2	1.7
Other and emerging	**-**	**0.1**	-	0.2	-	0.1	0.1	0.5	-
Total Canadian Operations	**30.3**	**30.4**	30.2	28.4	32.2	27.2	27.0	26.3	27.8
USA Operations									
Eagle Ford	**41.4**	**41.0**	41.9	42.8	49.1	46.0	37.9	39.8	36.0
Permian	**38.5**	**40.8**	36.3	32.8	38.4	36.7	28.1	29.5	26.7
Other Upstream Operations (1)									
DJ Basin	**11.3**	**10.6**	12.1	14.9	13.9	16.1	14.8	15.3	14.3
San Juan	**4.2**	**4.1**	4.3	6.2	5.0	6.8	6.6	6.4	6.7
Piceance	**2.9**	**2.8**	2.9	3.5	3.0	3.5	3.7	3.7	3.7
Other and emerging	**2.8**	**2.3**	3.1	4.8	3.4	4.1	5.9	6.3	5.5
Total USA Operations	**101.1**	**101.6**	100.6	105.0	112.8	113.2	97.0	101.0	92.9
Oil & NGLs Production (Mbbls/d)									
Total Core Four	**109.8**	**111.7**	108.1	102.9	119.2	109.4	91.4	93.9	88.8
% of Total Encana	**84%**	**85%**	83%	77%	82%	78%	74%	74%	74%

(1) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus.
(2) Natural gas production volumes from Bighorn have been included within Other and emerging for 2015.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2016			2015					
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Total Production (MBOE/d)									
Canadian Operations									
Montney	**155.6**	**151.2**	159.9	143.1	152.9	140.4	139.4	135.9	143.1
Duvernay	**16.9**	**18.3**	15.6	9.3	16.4	9.2	5.7	5.8	5.5
Other Upstream Operations (1)									
Wheatland	**13.6**	**14.2**	13.0	15.3	13.5	13.6	17.0	13.9	20.2
Deep Panuke	**6.5**	**2.0**	11.1	10.5	6.7	-	17.7	5.3	30.4
Other and emerging (2)	**7.4**	**6.5**	8.3	12.0	9.6	10.0	14.6	12.3	16.6
Total Canadian Operations	**200.0**	**192.2**	207.9	190.2	199.1	173.2	194.4	173.2	215.8
USA Operations									
Eagle Ford	**49.5**	**49.4**	49.6	50.1	58.6	54.0	43.9	45.8	42.0
Permian	**46.7**	**49.4**	44.0	40.1	46.5	45.7	34.1	35.8	32.3
Other Upstream Operations (1)									
DJ Basin	**20.6**	**19.8**	21.3	24.0	23.7	25.3	23.5	24.5	22.4
San Juan	**5.8**	**5.6**	6.0	8.4	6.8	9.3	8.8	8.9	8.8
Piceance	**49.6**	**48.7**	50.5	56.7	53.2	55.2	59.3	57.8	60.8
Haynesville	**-**	**-**	-	28.9	14.0	29.4	36.1	34.0	38.3
Other and emerging	**3.6**	**3.2**	4.1	7.5	4.9	6.2	9.2	8.7	9.7
Total USA Operations	**175.8**	**176.1**	175.5	215.7	207.7	225.1	214.9	215.5	214.3
Total Production (MBOE/d)									
Total Core Four	**268.7**	**268.3**	269.1	242.6	274.4	249.3	223.1	223.3	222.9
% of Total Encana	**72%**	**73%**	70%	60%	67%	63%	55%	57%	52%
Drilling Activity (net wells drilled)									
Canadian Operations									
Montney	**13**	**5**	8	15	1	-	14	6	8
Duvernay	**10**	**5**	5	15	6	2	7	1	6
Other Upstream Operations (1)									
Wheatland	**-**	**-**	-	105	-	34	71	-	71
Other and emerging	**-**	**-**	-	-	-	-	-	-	-
Total Canadian Operations	**23**	**10**	13	135	7	36	92	7	85
USA Operations									
Eagle Ford	**15**	**7**	8	65	14	10	41	14	27
Permian	**45**	**14**	31	177	35	44	98	52	46
Other Upstream Operations (1)									
DJ Basin	**-**	**-**	-	17	2	-	15	2	13
San Juan	**-**	**-**	-	1	-	-	1	-	1
Piceance	**-**	**-**	-	-	-	-	-	-	-
Haynesville	**-**	**-**	-	2	-	2	-	-	-
Other and emerging	**-**	**-**	-	3	-	-	3	-	3
Total USA Operations	**60**	**21**	39	265	51	56	158	68	90

(1) Other Upstream Operations includes total production volumes and net wells drilled in plays that are not part of the Company's current strategic focus.

(2) Total production volumes from Bighorn have been included within Other and emerging for 2015.

Encana Corporation

Further information on Encana Corporation is available on the company's website, www.encana.com, or by contacting:

INVESTOR RELATIONS

Brendan McCracken
Vice-President, Investor Relations
403.645.2978

Patti Posadowski
Sr. Advisor, Investor Relations
403.645.2252

GENERAL INQUIRIES

Encana Corporation
500 Centre Street SE
PO Box 2850
Calgary, AB, Canada T2P 2S5
Phone: 403.645.2000
Fax: 403.645.3400

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